STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE:

APPLICATION FOR RATE CHANGE
PURSUANT TO R.I.G.L. §§ 39-3-10 AND
39-3-11 OF NARRAGANSETT ELECTRIC
D/B/A NATIONAL GRID

DOCKET NO. 3943

DECISION AND ORDER

DATED: January 29, 2009

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE:

NATIONAL GRID GAS APPLICATION TO IMPLEMENT NEW RATES — DOCKET NO. 3943

TABLE OF CONTENTS

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE:

APPLICATION FOR RATE CHANGE PURSUANT TO R.I.G.L. §§ 39-3-10 AND 39-3-11 OF NARRAGANSETT ELECTRIC D/B/A NATIONAL GRID	DOCKET NO. 3943

DECISION AND ORDER

I. INTRODUCTION

On April 1, 2008, The Narragansett Electric Company d/b/a/ National Grid (the "Company") filed an application to increase the Company's base distribution revenues for the first time in almost ten years. The Company proposed an increase of $20.04 million, or 4.6% of total gas revenues, representing an additional $72 per year for a typical residential heating customer using 922 therms of energy. The primary factors cited by the Company in support of its rate increase application were increased operation and maintenance expenses, and the need to compensate for historic underinvestment by prior management in the distribution infrastructure. The Company also cited a need to address a loss of revenue due to increasing customer conservation over the years. The Company calculated that it had experienced annualized lost revenues totaling $7.64 million since June 2004 for the residential heating class alone.

The Company's rate application included a request that the Commission consider an important policy issue of first impression in Rhode Island: whether the Company's allowed distribution revenues should be decoupled from the volume of natural gas consumption by its customers. Under traditional ratemaking in Rhode Island and most of the United States,

distribution revenues are based on a volumetric charge established by the regulatory agency. To obtain an increase in the volumetric charge, and a resulting increase in revenues, the utility must in general file a base rate case and demonstrate to the satisfaction of the regulators that the utility's costs and expenses justify an increase. Fifteen states have allowed utilities to modify the volumetric distribution charge approved in a base rate case up or down as needed for the utility to collect an approved amount of distribution revenues, without further review by the regulatory agency. The parties and the Commission devoted considerable time and attention to understanding the advantages and disadvantages to ratepayers of the Company's decoupling proposal.

A. Conduct of the Proceeding.

The record in this case is unusually extensive and complex, addressing as it does numerous contested technical and financial issues as well as broad disputes over important issues of public and ratemaking policy. The Company's initial filing alone totaled over 1,000 pages of testimony and supporting documentation. In response to the Company's base rate application, the Commission received and considered voluminous and detailed pre-filed testimony and exhibits from experts employed by the Division of Public Utilities and Carriers ("Division"). Several intervenors requested and were granted permission to participate in the proceeding, including the Rhode Island Attorney General, the Rhode Island Office of Energy Resources, the George Wiley Center, Conservation Law Foundation, Environment Northeast, the Energy Council of Rhode Island, and Rhode Island Hospital. The intervenors submitted additional written testimony and exhibits. The Commission's review and consideration of these

voluminous materials was further complicated by the restrictive limits on communications with Commission staff recently imposed by the Rhode Island Supreme Court.[1]

After the initial filing, the parties engaged in extensive discovery proceedings. The Commission, Division and other parties propounded over 500 data requests to the Company for information relating to the Company's and its affiliates' management, operations and finances. The Company provided hundreds of pages of written answers and supplemental documentary material in response. The Company also responded to numerous record requests made during the course of the public hearings on this docket.

The Commission conducted twelve days of evidentiary hearings on the Company's proposal in September and October, 2008. Over 160 exhibits, totaling thousands of pages of information, were received into evidence. The Company, Division and other parties presented seventeen witnesses:

<u>For the Company:</u>

1. Nickolas Stavropoulos, Executive Vice President of Gas Distribution-US for National Grid, with responsibility for the Company's regulated gas distribution operations in Rhode Island, Massachusetts, New Hampshire and New York, testified for the Company regarding its overall business operating plan and decoupling proposal;

2. Michael Laflamme, Director of Revenue Requirements for National Grid USA Service Company, Inc., testified for the Company regarding its single year revenue requirement analysis, including sharing of net synergy savings from both the National Grid/Southern Union and National Grid/KeySpan transactions;

3. Susan Fleck, Vice President of Engineering Standards and Policy for National Grid USA, testified for the Company regarding its accelerated pipeline replacement program;

4. Peter Czekanski, Manager of Pricing for National Grid Rhode Island – Gas, testified for the Company regarding adjustments to test year billing determinants and revenues that produce rate year billing determinants, and the Company's proposed tariff changes;

[1] *See Arnold v. Lebel*, 941 A.2d 813 (R.I. 2007).

5. Sean Mongan, Director of Operations and Process Support for the Energy Solutions Service Group for National Grid USA, testified for the Company regarding its proposed Gas Marketing Program;

6. Paul Moul, Managing Consultant, P. Moul & Associates, testified for the Company regarding an appropriate rate of return;

7. Robert Hevert, President, Concentric Energy Advisors, testified on behalf of the Company regarding the effect of decoupling on an appropriate rate of return;

8. James Simpson, Vice President, Concentric Energy Advisors, testified for the Company regarding the mechanics of the Company's decoupling proposal;

9. David Heintz, Assistant Vice President, Concentric Energy Advisors, testified for the Company to explain the Company's proposed rate design for the gas business in Rhode Island;

For the Division:

10. David Effron, a consultant specializing in utility regulation, testified on behalf of the Division of Public Utilities and Carriers regarding the Company's proposed revenue requirement, the proposed pension reconciliation mechanism, and the accelerated pipeline replacement expense reconciliation mechanism;

11. James Rothschild, a financial consultant specializing in utility regulation, testified on behalf of the Division of Public Utilities and Carriers regarding the Company's proposed cost of capital with and without decoupling;

12. Don Ledversis, Gas Inspector for the State of Rhode Island, testified on behalf of the Division of Public Utilities and Carriers regarding the condition of the Company's distribution infrastructure;

13. Bruce Oliver, President, Revilo Hill Associates, testified on behalf of the Division of Public Utilities and Carriers regarding the Company's proposed revenue requirement, decoupling, non-firm distribution rates, and other rate design issues;

For the Intervenors:

14. John Farley, Executive Director, The Energy Council of Rhode Island, testified on behalf of TEC-RI regarding the Company's decoupling, low income discount and non-firm distribution rate proposals;

15. James DeMetro testified on behalf of Rhode Island Hospital regarding the Company's proposed non-firm distribution rates;

16. Seth Kaplan, Vice President for Climate Advocacy and the Director of the Clean Energy/Climate Change Program, Conservation Law Foundation, testified on

behalf of the Conservation Law Foundation regarding the Company's decoupling proposal;

17. James Grasso, President, Silent Sherpa Energy Consulting and Professional Services, Inc., testified on behalf of Silent Sherpa regarding the Company's non-firm distribution rates.

All parties, Commissioners, Commission counsel, and Commission staff were given broad latitude to examine the witnesses regarding their pre-filed direct and rebuttal testimony, and to introduce supplemental testimony and other evidence during the hearings. At the direction of the Chairman, the hearings were conducted so as to ensure a full and compete record for the Commission to consider in deciding the case.

The Commission also received and carefully considered numerous public comments. The Commission heard public comment on the Company's proposals from 30 individuals at open meetings held in Pawtucket, Woonsocket, Middletown and Warwick in June 2008: Sally McAuley, Raymond Matthew, Ernie Marot, Michael Dyer Ryan, Julie Silvia, Darlene Magaw, Joseph Pamula, Cindy Chompka, Jackie Archambault, Jim Healy, Charles A. High, Henry Shelton, John A. MacLennan, Don Mallinson, Frank Bozyan, Irene Santos, Manuel Marques, Elizabeth Dees, Bill O'Connell, Harry Bogosian, Virginia Gonsalves, Sister Carol Weaver, Stephanie Cannady, Lela Coons, Marie C. Hennedy, John Colby, Elizabeth Marsis, Maggie Rogers, Erik Dufresne and Roberta Fitton. The Commission heard additional public comment from 21 individuals during the evidentiary hearings: Julie Gill, Christopher Powell, Peter Cassels, Jan Campbell, Michael Januario, Karina Lutz, Sandra Morra, Elaine Gambardella, Stephen Kapalka, Jessica Jennings, Thomas J. Murphy, Michael Seymour, Kenneth Clark, Nancy Clark, Elizabeth Clark, Donald DeSantis, Kathie Foorsheim, Sally Lapides, David Pallante, Judith Croyle and Charles Pinning. Customers who commented were opposed to a rate increase and concerned about the effects on their households, particularly elderly and at-risk

households. Customers were also concerned about the collateral effects of rate increases on businesses, churches, schools and non-profit organizations. Several customers commented that the Company should be more aggressively trying to reduce its costs, rather than increasing rates. Other customers complained about the Company's failure to communicate adequately with customers about Company initiatives, particularly efforts by the Company to relocate gas meters to the front of customers' homes, and about deficiencies in the Company's Value Plus Installer conversion program.

After the conclusion of the hearings, the parties and intervenors submitted post-hearing briefs summarizing the arguments and evidence presented, and addressing certain legal issues presented by the Company's proposals. The Commission also received reply briefs from the parties and intervenors commenting on each others' post-hearing submissions.

B. <u>Applicable Legal Standards</u>

As noted above, many public commentors expressed the view that energy costs have increased significantly in recent years and that no rate increases should be allowed. The Commission takes seriously its responsibility to thoroughly review proposed rate increases, and has devoted substantial time and resources to investigating the justification for the Company's proposed expenses, ultimately reducing the Company's revenue request by a substantial amount. At the same time, the Commission must allow the Company sufficient resources to deliver safe and reliable natural gas service to approximately 250,000 customers who rely on gas in their homes and business in virtually all cities and towns statewide. The Company, like its customers, faces rising costs for the goods and services it needs to deliver natural gas. The Company's interim filings relating to increases or decreases in the commodity cost – the cost of natural gas itself – do not address these distribution costs.

The Rhode Island General Assembly has declared that it is the policy of the state

> To provide fair regulation of public utilities and carriers in the interest of the public, to promote availability of adequate, efficient and economical energy, communication and transportation services and water supplies to the inhabitants of the state, to provide just and reasonable rates and charges for such services and supplies, without unjust discrimination, undue preferences or advantages, or unfair or destructive competitive practices . . . . .

R.I.G.L. § 39-1-1; *see also* R.I.G.L. § 39-2-1 (utility rates and charges must be "reasonable and just"); R.I.G.L. § 39-2-2 (prohibiting rate discrimination). The Commission's review of the Company's proposals must be conducted taking this policy into account. The Company bears the burden of proof to show that its rate increase is necessary in order to obtain just and reasonable compensation for the service rendered. R.I.G.L. § 39-3-12. There is no single formula for measuring just and reasonable rates; the Commission has discretion to select a measurement approach that is supported by the record. *Providence Gas Co. v. Burman*, 119 R.I. 78, 376 A.2d 687 (1977).

C. <u>Summary of Decision.</u>

The Commission rendered its decisions on the issues presented by the parties at an open meeting on November 24, 2008. As reflected in the Company's compliance filing, the Commission's decisions in this docket result in the Company's revenue deficiency being reduced from the $20,036,103 initially proposed to $13,659,773. Thus, the Company's allowed distribution revenue will increase by 10.88% from $125,606,713 to $139,266,486. For a typical residential heating customer using 922 therms of natural gas, the approved new base rates represent an increase of $56 per year. Combined with other scheduled changes under the Gas Cost Recovery and Distribution Adjustment Clause, however, this will result in a net 4.1% rate reduction, which translates to an annual reduction of about $64 per year. The Commission denied the Company's proposed return on equity of 11.5%, finding that a lesser return of 10.5% is just and reasonable. Other regulatory adjustments include: reducing the Company's proposed

health care expense by $907,456; reducing the Company's proposed FAS 112 expense (relating to post-employment benefits other than pension) by $170,000; reducing the Company's proposed synergy savings from the Southern Union merger by $1,054,609; eliminating the Company's proposed $1,377,000 gas marketing program; and reducing the Company's proposed low income uncollectible accounts receivable adjustment by $150,000.

The Commission also (1) approved a 10% distribution rate discount for qualifying low income customers, (2) approved the Company's accelerated pipeline replacement program to address the increasing number of gas leaks in Rhode Island's aging distribution infrastructure, (3) approved the Company's proposed reconciling mechanism for pension and post-retirement benefits other than pension expense, and (4) approved distribution rates for non-firm transportation customers that will be set at a fixed percentage of 80% of the otherwise applicable firm transportation rate. The Commission rejected the Company's proposed revenue decoupling mechanism and a proposed reconciling mechanism for gas-supply related bad debt.

In granting the Company a distribution revenue increase of $13,659,773, the Commission is allowing additional funds for the Company to modernize its infrastructure and provide safe, efficient and reliable service to customers. The Commission's adjustments to the Company's proposed expenses and the revised 10.5% return the Company will be allowed to earn on its investment reflect the difficult economic conditions in the state that are faced by both the Company and its customers. The 10.88% revenue increase granted by the Commission is significantly lower than the approximately 16% increase requested by the Company; however, the Commission believes that the rates it has allowed are just and reasonable and will permit the Company to earn a fair rate of return. The Commission believes that it has properly balanced the

competing interests presented by the parties, consistent with the Commission's statutory duty under Rhode Island law.

II. SUMMARY OF THE COMPANY'S RATE FILING.

The Company's initial filing requested a base revenue increase of $20,036,103 million, to $149,885,295. Ex. NGrid 3 at 6 (Laflamme Direct). The Company developed its revenue request based on a test year ending September 30, 2007. The Company made adjustments to test year revenues and expenses to reflect "known and measurable" changes relating to any one-time, out of period or unusual activities. Ex. NGrid 3 at 7 (Laflamme). *See Narragansett Electric Co. v. Harsch*, 117 R.I. 395, 368 A.2d 1194 (1977) (Commission may accept known and measurable changes that affect test year data with certainty). The Company then made a number of pro forma changes to reflect anticipated cost and revenue changes through the end of the rate year, September 30, 2009. These include changes in labor and benefit costs, postal rate increases, adjustments for the pending sale of the Company's Providence, R.I. office, rate case expenses and inflation. The operating results were also adjusted to include operations & maintenance expense and capital costs associated with the Company's proposed Gas Marketing Program and accelerated infrastructure replacement program. Ex. NGrid 3 at 8 (Laflamme).

To calculate the $149 million of base revenues proposed in its initial filing, the Company (1) excluded actual Gas Cost Recovery revenues recorded in the Test Year, (2) adjusted interruptible firm revenues to the base rate credit level of $1.6 million, (3) eliminated actual energy efficiency surcharges recorded in the test year, (4) eliminated actual gross receipts tax collections and gross receipts tax expense recorded during the test year, (5) adjusted operating revenue related to out of period, non-recurring, unbilled and weather normalization revenues recorded in the test year, (6) adjusted for the Company's service contract program

costs, and Allowance for Funds Used During Construction and interest on customer arrears, and (7) adjusted all components of the test year base rate revenues to reflect normal weather. The Company also made pro forma adjustments to reflect total base rate revenues expected in the rate year, including adjustments to the base rate recovery component for the Low Income Heating Assistance Plan, Low Income Weatherization Program, Advanced Gas Technologies Program, and Environmental Remediation cost recovery. Ex. NGrid-3 at 9-10 (Laflamme).

To calculate the $123 million of operating expenses proposed in its initial filing, the Company (1) eliminated from the cost of service total gas expenses of $300,428,013 recorded in the test year, (2) excluded non-gas O&M expenses recovered through the GCR, (3) eliminated gas-related uncollectible expenses at the test year uncollectible rate of 2.10%, (4) corrected an accounting error associated with Environmental Remediation cost amortization, (5) excluded energy efficiency expenses and gross receipts tax expense recorded in the test year, (6) adjusted test year Y2K and legacy system amortization expense, (7) excluded an expense credit erroneously recorded in the test year, (8) included an expense credit for overhead associated with test year service contract labor, (9) eliminated certain computer hardware lease expense, (10) adjusted the Company's accrued vacation liability, (11) adjusted for a medical expense billing lag, (12) reclassified donations to other O&M categories, (13) excluded all costs to achieve merger synergies from the Southern Union and KeySpan transactions, and (14) excluded the approved merger synergy allowance from the Southern Union transaction. The Company also made pro forma expense adjustments to test year salary and wages, medical and dental expenses, group insurance expenses, pension and other post-retirement benefit expenses, employee thrift plan expenses, postage expenses, rate case expenses, office expenses, automated meter reading

expenses, LNG-related expenses, and made an inflation adjustment. Ex. NGrid-3 at 11-24 (Laflamme).

The Company made additional adjustments to depreciation expense ($911,576), municipal tax expense ($213,448), and payroll tax expense ($188,066). The Company's depreciation study resulted in a composite depreciation rate of 3.36%. Excluding the Company's investment in the Providence, Rhode Island office, the composite depreciation rate is 3.38%. This composite rate was applied to rate year depreciable plant to arrive at rate year depreciation expense. For municipal tax expense, the Company calculated a three year average percentage increase of 1.38%, and applied this rate of increase to the Company's most recent 2007 municipal tax assessment, adjusted to exclude the Providence, Rhode Island office property. Payroll tax expense was adjusted by applying the net change in rate year versus test year O&M salaries and wages to test year payroll tax expense. Ex. NGrid-3 at 40-42 (Laflamme).

The Company proposed a rate base of $285,241,458. Ex. NGrid-3 at 44 and Attachment NG-MDL-1 at 24. To calculate rate base, the Company used a five quarter average of net plant in service plus cash working capital, materials and supplies, prepayments and deferred debits, less deferred income taxes, customer deposits and an injuries and damages reserve. The Company included a hold harmless base rate credit of $30,337,343 relating to the tax asset basis step up realized by the Company upon its acquisition of the regulated Rhode Island gas assets of New England Gas Company. Both plant in service and accumulated depreciation amounts were adjusted for the anticipated sale of the Company's Providence, Rhode Island office. The Company's proposal was based on forecasted additions to plant in service of $36,679,000 in the twelve months ending September 30, 2008, and $60,780,000 in the twelve months ending September 30, 2009. Ex. NGrid-3 at 42-44 and Attachment MDL 1, p. 26 of 33.

The Company proposed an overall cost of capital of 9.27%, including a return on equity of 11.5%. Ex. NGrid-3 at 45.

The Company also requested a number of significant modifications to its tariff. These included: (1) introducing a revenue decoupling mechanism to reconcile actual annual revenue per customer with the revenue per customer approved in this rate case; (2) introducing new annual reconciling mechanisms for certain expenses previously fixed in base rates, including pension and other post-retirement benefit expense and commodity-related bad-debt expense; (3) introducing a discounted billing rate for low income customers, and (4) capping value of service pricing for interruptible service customers at 150% of the comparable firm tariff rate.

III. DECISION

A. Revenue Requirement Issues.

The Company's proposed revenue deficiency is based in part on three contested items: (1) the percentage of common equity to be included in the Company's capital structure for ratemaking purposes, (2) the appropriate cost of common equity, and (3) the allowable rate base through the end of the rate year. These items are addressed in turn below.

1. Capital Structure

The Company and the Division agree that, although the Company's Rhode Island natural gas operations are a division of The Narragansett Electric Company ("Narragansett Electric"), Narragansett Electric's actual capital structure contains a large proportion of common equity and is inappropriate for use in the ratemaking process. Ex. NGrid-9 at 10-11.[2] The

[2] Narragansett Electric is a subsidiary of National Grid USA. National Grid USA is a subsidiary of National Grid plc. The capital structure of National Grid USA and Subsidiaries as of September 30, 2007 was about 60% equity and 40% debt. The capital structure of Narragansett Electric was about 90% equity and 10% debt. Ex. NGrid-9 at 11-12 (Moul Rebuttal); Data Response COMM 3-4.

Company and the Division disagree, however, on the appropriate alternative measure. The Company proposed a capital structure of 47.71% equity, 40.63% long-term debt, and 11.66% short-term debt, calculated based on the equity ratios of a proxy group of other U.S. natural gas utilities. Ex. NGrid-8 at 4 (Moul). The Division proposed using the capital structure of the Company's parent, National Grid plc: 37.77% equity, 59.06% long-term debt, and 3.17% short term debt. Division Post-Hearing Mem. at 5; Ex. DIV-5, JAR Schedule 1 (Rothschild).

Company Position. The Company argued that its parent company's capital structure should not be used for ratemaking for several reasons. First, it would mean using the capital structure of a non-domestic, unregulated holding company that owns and operates a global operation encompassing a wide range of unregulated activities. The unregulated activities have different business risks. Ex. NGrid-9 at 9-16; Tr. 9/10/08 at 9-10. The Division's expert should have, but did not, take into account the nature of National Grid plc's unregulated activities or the reasonable range of capital structures in the United Kingdom. Tr. 9/11/08 at 74-75.

Second, the record is clear that the capital structure recommended by the Division is not typical of a capital structure for a regulated gas company operating in the U.S. *See, e.g.*, Ex. DIV-31. In that regard, the record shows that the average capital structure associated with the proxy group that the Division's witness uses for the ROE calculation has an average common equity ratio of 49.12% and the median is 47.05%. Ex. DIV-5 at Schedule JAR-7; Ex. NGrid-9 at 14; Tr. 9/10/08 at 12-13. In addition, the Division's own data shows that no regulated gas or electric utility obtaining a Commission decision on a rate case year-to-date in 2008 had a capital structure with less than 41% common equity and no regulated gas company had a common equity ratio less than 46% common equity. Ex. DIV-31 at 4-5. The average common equity

ratio was demonstrated to be 52.06%. *Id.* As a result, these factors underscore the unreasonableness of the Division's recommendation and argue for adoption of the Company's proposed capital structure.

Third, the record shows that there is a different regulatory structure in the UK and that the regulator of National Grid's UK business does not utilize the capital structure represented by its U.S. Generally Accepted Accounting Principles ("GAAP") accounts when setting rates. *Id.* at 17-18; Tr. 9/10/08 at 10-11, 50-52. Instead, rates are set in the UK based on a Regulatory Asset Value ("RAV"). The RAV has no direct relationship to the book value of the UK businesses and was derived from a combination of replacement cost and market value that is increased by inflation every year. Thus, even if it were appropriate to impute the capital structure for National Grid plc to the Rhode Island operations, which it is not, the equity component determined in accordance with the US GAAP must be adjusted to recognize the difference between the RAV and the US GAAP book value of the UK regulated businesses. This procedure is necessary to ensure that National Grid's consolidated capital structure as applied to the Company reflects the regulatory value of assets in both the US and the UK. The adjustment would increase National Grid's consolidated common equity ratio determined in accordance with US GAAP by approximately eight percentage points. Ex. NGrid-9 at 17-18.

Fourth, the record shows that, even if it were appropriate to look to National Grid plc for the capital structure, the Division's witness has not correctly stated the equity ratio for National Grid plc in accordance with U.S. GAAP. *Id*. at 15. Specifically, in calculating the parent company's capital structure, the Division's witness failed to take into account approximately $3.7 billion of cash, cash equivalents and marketable securities carried on its fiscal 2007 balance sheet. *Id.* These cash balances should have been subtracted from

outstanding debt balances to compute the capital structure ratios, but were not. *Id.* at 15-16. If this correction were made, the common equity ratio for National Grid plc would total 44.36%, and adjusted for the RAV of National Grid plc/s regulated UK businesses, the actual common equity ratio that would apply to the Rhode Island operations would be 52.19%, rather than the 37.77% incorrectly calculated by the Division's witnesses. *Id.* at 16-18.

Significantly, the Division's witness testified that he was "not aware" of the differences in the UK regulatory system before he made his recommendation on capital structure. Tr. 9/10/08 at 193. The witness further testified that he only became aware of the RAV method of dealing with rate base after receiving a response to a data request on the Company's rebuttal testimony. *Id.* at 194. The witness testified that he felt he was on "comfortable ground" with the "end result" without knowing anything about the RAV. *Id.* at 194-195. However, given the differences that do exist and are proven on the record for this proceeding, it is clear that an accurate calculation cannot be performed without knowledge of the RAV implications. Therefore, this omission has the effect of undermining the "end result" recommended by the Division's witnesses.

Division Position. In rebuttal, the Division argued that using the capital structure of National Grid plc is reasonable because (1) the debt rating of the Company's Rhode Island operations is dependent on the financial condition of the holding company, (2) the subsidiary's common equity was not raised from common equity holders, but through debt sources from the parent, (3) the holding company's A minus bond rating indicates that its capital structure is appropriate, (4) using the Company's 47% common equity ratio does not carry any value to ratepayers given that Rhode Island operations would still be financed by the UK holding company that maintains a lower equity percentage, and (5) if the Company's ratio is used, "not

only would Rhode Island ratepayers fund much more costly equity that, in reality, is never actually utilized for the Rhode Island operations, the hypothetical equity would then have to be grossed up for federal income taxes for an overall cost rate of almost 17.7%." Division Post-Hearing Mem. at 5-9; Tr. 9/11/08 at 76-77, 120-123 (Rothschild); Ex. DIV-6 at 6-7 (Rothschild Rebuttal).

Commission Decision. The Commission will use a utility's actual capital structure in setting rates, unless that capital structure is not reasonable for rate-setting purposes. If the actual capital structure is not reasonable for rate-setting purposes, the Commission may impute a capital structure consistent with market's expectations for a regulated utility. *Blackstone Valley Electric*, Order No. 13877 (1992) (using actual capital structure); *The Narragansett Electric Company*, Order No. 14857 (1995) (settlement using actual capital structure); *The Narragansett Electric Company*, Order No. 16200 (2000) (settlement using imputed capital structure); *In re New England Gas Company*, Docket No. 3401 (2002) (settlement using imputed capital structure of 43.6% common equity). The Commission finds that the Division's reliance on the actual capital structure of National Grid plc is not appropriate because the Division's expert did not make adjustments that should have been made to recognize the different treatment of regulatory assets in the U.K., or the approximately $3.7 billion of cash and equivalents on National Grid plc's balance sheet. Ex. NGrid-9 at 15, 17-18. The evidence indicated that the Division's expert was unfamiliar with U.K. accounting conventions cited by the Company until after he submitted his direct testimony. Tr. 9/10/08 at 193-195. The Company's proposed capital structure is more typical of a capital structure for a U.S. regulated gas company. Ex. DIV-5, Schedule JAR-7; Ex. NGrid-9 at 14; Tr. 9/10/08 at 12-13. For all of these reasons, the Commission approves the Company's proposed capital structure of 47.71%

equity, 40.63% long-term debt and 11.66% short-term debt based on the proxy group of other U.S. natural gas utilities.[3]

2. <u>Return on Equity.</u>

The Company proposed a weighted average cost of capital of 9.19% and an allowed return on equity of 11.50%. Ex. NGrid-8 at 2 (Moul). The Division proposed a weighted average cost of capital of 8.56%[4] and an allowed return on equity of 9.95%, assuming the Division's proposed capital structure. Ex. DIV-5 at 4 (Rothschild).[5] The Company proposed, and the Division did not question, continuing the existing earnings sharing mechanism for earnings above the allowed rate of return. Earnings up to 100 basis points above the allowed return on equity established in this proceeding will be shared 50/50 between ratepayers and the Company. Earnings of more than 100 basis points above the allowed return will be shared 75/25 between ratepayers and the Company. Ex. NGrid-15, Attachment NG-PCC-5 at 231; NGrid Response to Commission Record Request No. 24.

<u>Company Position</u>. The Company arrived at its proposed return on equity by measuring the cost of equity of a proxy group of seven natural gas companies using four methods: discounted cash flow ("DCF"), risk premium analysis ("RP"), capital asset pricing model ("CAPM"), and comparable earnings approach ("CE"). Ex. NGrid-8 at 5 (Moul).

The DCF model measures the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. At its simplest, the DCF return on common stocks consists of a current dividend yield and future price

---

[3] Commissioner Bray dissents from this portion of the Decision and would adopt the Division's position for reasons stated on the record at the November 24, 2008 Open Meeting. Tr. 11/24/08 at 107.

[4] Based on projected cost of short-term debt of 2.58% vs. the Company's projected short-term debt cost of 4.59%. Tr. at 8/27/08 at 156.

[5] The Division proposed a cost of equity of 9.50% if its recommended capital structure were not used. Division Post-Hearing Reply at 2; Ex. DIV-5 at 4 and Schedules JAR 2 and 7.

appreciation of the investment. The DCF methodology requires the use of an expected dividend yield to establish an investor-required cost of equity. The adjusted dividend yield for the Company's proxy group was 3.86%. The Company's expert calculated a growth rate of 5.25%, a 0.54% upward leverage adjustment, and a 0.19% upward adjustment for flotation costs. Ex. NGrid-8 at 22-38 (Moul).

Under the risk premium approach, the cost of equity is determined by corporate bond yields plus a premium to account for the higher risk of equity compared to debt. The Company's expert concluded that a 6% yield on A-rated public utility bonds represents a reasonable yield expectation, and that 5.25% is a reasonable common equity risk premium. Ex. NGrid-8 at 38-43 (Moul).

The CAPM methodology uses the yield on a risk-free interest bearing obligation plus a rate of return that is proportional to the systematic risk of an investment. To compute the cost of equity using the CAPM method, three components are needed: a risk free rate of return, the beta measure of systematic risk, and the market risk premium derived from the total return on the market of equities reduced by the risk-free rate of return. The CAPM also takes into account the size of the company or portfolio for which the calculation is performed. The Company's expert calculated a 4.75% risk free rate of return, a leverage adjusted beta of 1.02, a market premium of 7.39% and a size adjustment of .97% to arrive at a CAPM return of 13.45%. Ex. NGrid-8 at 44-49 (Moul).

The Comparable Earnings approach looks at the returns realized by unregulated companies with risks that are comparable to regulated public utilities. One method involves selecting another industry or industries with comparable risks to a public utility, and then using the results for all companies in that industry as a benchmark. A second method involves

selecting parameters that represent similar risk traits for the public utility and unregulated comparables. The Company's expert selected comparable unregulated companies with six categories of comparability designed to reflect the risk of natural gas utilities. Under the Company's CE approach, the cost of equity was 13.90%. *Id.* Ex. NGrid-8 at 49-53 (Moul).

The average return of the Company's DCF, RP and CAPM models was 11.58%, which the Company adjusted to arrive at its proposed return of 11.50%. NGrid Post-Hearing Mem. at 12; Ex. NGrid-8 (Moul Pre-Filed Direct Testimony) at 7.

The Division's proposed rate of return is inordinately low for several reasons. First, the Division expert's DCF model uses the "retention growth rate" method, which requires an assumption of the return on book common equity for a proxy group. Ex. NGrid-9 at 22-23; Tr. 9/12/08 at 22-24. The Division's expert selected 12% for his key input value, which was the second lowest value in his data set of 10 values. *Id.* This approach introduced a "significant downward bias" causing the DCF results to be biased and unreasonably low. *Id.* To be valid, the Division's expert should have selected a balanced approach using a measure of central tendency, such as an average of the values, the median or a midpoint. Tr. 9/12/08 at 22-24. A balanced approach would have resulted in a higher value comparable to the Company's calculation (such as 10.25%, 10.03% and 10.68% depending on the choice of central tendency measure). *Id.*

Second, the Division's rate of return on common equity is significantly lower than almost any other utility for which a rate of return has been set in the most recent reported rate cases, according to information submitted by both the Company and the Division. *Id.* at 5; Ex. DIV-31. According to the Company's data, the average rate of return on common equity for natural gas utilities was 10.27% in the period October 1, 2006 through August 31, 2007. Ex.

NGrid-9 at 5 (Public Utility News, dated December 28, 2007). According to the Division's data, the average rate of return on common equity for natural gas utilities was 10.24% in calendar year 2007 and 10.35% for the first two quarters of 2008. Ex. DIV-31 (Regulatory Research Associates, dated July 2, 2008).

Third, the Division's rate of return fails to take adequate account of volatility in the capital markets and turmoil in the credit markets. The record shows that the cost of common equity has increased as a result of the global financial crisis because of a large increase in the risk premium which is currently estimated to be a 50 to 100 basis point increase in the cost of equity capital. Ex. NGrid-9 at 6-8; Tr. 10/22/08 at 21-22, 66-67. The Company is facing a significant new challenge in terms of assuring investors that their capital is safe with the Company. Ex. DIV-69. There can be no dispute that the Company will be faced with market realities in financing its operations following the Commission's rate case decision, and therefore, these realities need to be considered in the final result.

Lastly, the Division's expert failed to provide any record support for his 45 basis point adjustment to the cost of common equity to account for the higher financial risk associated with this proposal to set rates based on National Grid plc's lower common equity ratio. The Company demonstrated that rather than making an arbitrary adjustment, there are objective methods widely accepted in the financial literature that can be used to quantify the impact of a lower equity ratio on the cost of common equity. Ex. NGrid-9 at 37. By applying these methods, the Company demonstrated that, if the Commission sets rates based on National Grid plc's equity ratio of 37.77%, rather than the Company's proposed 47.71% ratio, the return on equity decided in this proceeding should be adjusted upwards by 98 basis points not 45 basis points. *Id.* at 3.

Division Position. The Division based its recommendation on the DCF method, applied to a comparative group of natural gas utilities. Ex. DIV-5 at 10 and Schedule JAR 3 (Rothschild). The Division's expert also presented a CAPM analysis to support his conclusion. Ex. DIV-5 at 24 (Rothschild). The Division disputed the Company expert's DCF methodology because it added a 0.54% upward leverage adjustment, and a 0.19% upward adjustment for flotation costs. The Division presented testimony that these adjustments are contrary to basic finance principles, and incorporate earnings per share growth rates that are not reflective of long term sustainable growth required for the constant growth form of the DCF analysis. Ex. DIV-5 at 57 (Rothschild). The Division also argued that the Company's risk premium analysis is inconsistent with Commission precedent, Ex. DIV-5 at 58-63 (Rothschild), and that the Company's CAPM analysis is flawed. Among the errors in the Company's CAPM analysis, (1) it improperly uses the arithmetic average, (2) it uses short term analyst forecasts as a proxy for long term sustainable growth, (3) it uses Value Line's five-year projection of total returns on the stock market as if it were intended to be a reflection of investor expectations when, in fact, Value Line has no such intention, and (4) it improperly inflates the beta as applied to the risk premium. Ex. DIV-5 at 64 (Rothschild).

Commission Decision. The Commission has historically expressed a preference for the use of the DCF methodology to determine return on equity. *See, e.g., In re Valley Gas Co. & Bristol & Warren Gas Co.*, Docket No. 2276, Order No. 14834, at 12 (1995) ("this Commission has consistently stated its preference for the use of the discounted cash flow (DCF) methodology"). Using the DCF methodology and a proxy group of companies, the Division's expert arrived at a 9.95% return. However, the record reflects that minor adjustments to the Division's DCF methodology would have produced a higher return. For example, the Division's

DCF expert used 12% as a key input value, which was the second lowest value in his data set of ten values for his proxy group. If he had used the average value of this data set his DCF result would have moved to 10.25%. Ex. NGrid -9 at 22-23; Tr. 9/12/08 at 22-24.

The Company arrived at its proposed 11.5% return on equity by averaging the results of three out of four return on equity calculations, and making upward adjustments to some of its calculations that were challenged by the Division. Ex. NGrid-8 (Moul Pre-Filed Direct Testimony) at 7-8. While the Company's expert proffered explanations for his blended approach, the Division presented evidence that alternate assumptions and calculations would significantly lower the Company expert's result. For example, the Division presented credible evidence that the Company's CAPM analysis, which produced a return on equity of 13.45%, contained a number of flaws. Ex. DIV-5 at 44-45 (Rothschild). The Division also presented testimony that the Company's use of a leverage adjustment and a flotation cost adjustment in its DCF calculation were inappropriate. Ex. DIV-5 at 57 (Rothschild). Excluding these adjustments would have reduced the Company's return on equity based on the DCF method to 9.11% from 9.84%, and reduced the Company's proposed blended rate of return accordingly. Ex. NGrid-8 (Moul Pre-filed Direct Testimony) at 7-8.

The Commission therefore finds that while the expert analyses presented by the Division and the Company are useful indicators of a reasonable range for a return on equity, neither is definitive. In arriving at this conclusion, the Commission notes that the Division's proposed return on equity is below – and the Company's above – recent average rates of return on common equity for other U.S. natural gas utilities. Evidence submitted by the Company, and not disputed by the Division, shows that the U.S. average return on equity for gas utilities is 10.27%. Approximately two thirds of U.S. gas utilities have been allowed returns on equity

between 10 and 10.9%. Tr. 8/27/08 at 23-24; Ex. NGrid 9 at 5 (Moul). Some of the other natural gas utilities with allowed returns in this range have decoupling mechanisms in place. Ex. NGrid-18 at 11 (Hevert); Tr. 9/10/08 116-123. The record reflects that while many utility commissions have not made explicit reductions to authorized return on equity on account of decoupling, there is evidence that in some proceedings the regulatory agency has found it appropriate to reduce the return on equity of a utility that has revenue decoupling. Ex. NGrid-18 at 26 (Hevert).

The Division argued that recent statements by the Company's chief executive officer to investors support a return on equity below 10%. For example, in October 2008 the chairman and CEO told investors that National Grid plc is an "extraordinarily low risk" company with very solid returns. Ex. DIV-70. Investors were further told that "[w]e are a very low risk business." Ex. DIV-69 at 6; Tr. 10/22/08 at 76. Without further evidence to show what "low risk" meant to the speaker making these statements, however, they have little probative value.

Based on all of the evidence presented, the Commission finds that 10.5% is a reasonable return on equity for the Company's Rhode Island operations. This return on equity is comparable to the U.S. average for natural gas utilities, with a slight upward adjustment in recognition of the market turmoil that has occurred since the Company submitted its filing in April 2008. Ex. NGrid 9 at 14-24 (Moul Rebuttal) (recent economic conditions which the Company believes will increase the cost of equity capital). The Commission has the discretion to grant a return on equity that brings the Company in line with other comparable utilities. *See Narragansett Electric Co. v. Harsch*, 117 R.I. 395, 368 A.2d 1194 (1977) (utility may be granted rate of return sufficient to bring its return in line with those currently achieved in the same region by entities with similar risks). A return on equity of 10.5%, when applied to the Company's

approved rate base, should enable the Company to serve its customers effectively and adequately compensate investors for risks assumed.[6]

3. Size of Rate Base.

The Company proposed a rate base of $285,241,458. Ex. NGrid-3 at 44 and Attachment NG-MDL-1 at 24. The Company's proposal was based on forecasted additions to plant in service of $36,679,000 in the twelve months ending September 30, 2008, and $60,780,000 in the twelve months ending September 30, 2009. Ex. NGrid-3 at 42-44 and Attachment MDL 1, p. 26 of 33. The Division proposed reducing average rate year plant in service by $10,259,000, resulting in a net rate base reduction of $9,980,000 to $275,261,000. NGrid Post-Hearing Mem. at 17.

Company Position. The Company argues that the budgeted expenditures for plant additions will be incurred. A lag in contractor billing is responsible for actual spending in the early months of the period running below budget. Tr. 9/9/08, at 9-10, 12 (Fleck). The Company further argues that the Division's adjustment incorrectly assumes that spending on additions is linear. The Company offers to update its responses to Data Requests DIV 1-2 and DIV 13-4 through October 2008 and represents that they would show that the gap between budgeted and actual spending is narrowing. NGrid Post-Hearing Reply at 20. The Company also represents that it does not object to an adjustment in the rate year end plant in service amount if the projected capital spending does not occur. *Id*. at 19.

Division Position. The Division reduced the proposed rate base after reviewing the Company's actual capital expenditures for the period October 2007 through March 2008, and determining that they were only $14.36 million, or 19.4% below budget. Ex. DIV-8 (Data

[6] Commissioner Bray dissents from this portion of the Commission's decision and would adopt the Division's position for reasons stated on the record at the November 24, 2008 Open Meeting. Tr. 11/24/08 at 110.

Request DIV 1-2). Based on those actual expenditures, the Division asserts that the Company has overstated its forecasted capital additions in the 12 months ending September 30, 2008 by $5,282,000, and overstated forecasted capital additions for the twelve months ending September 30, 2009 by $9,954,000.

Commission Decision. At the hearings, the Company presented evidence that the budgeted expenditures will be incurred. Tr. 9/9/08 at 9-10 (Fleck). The Company's testimony that a lag in contractor billing is responsible for actual spending in the early months of the period running below budget was not rebutted. Tr. 9/9/08 at 9-10, 12 (Fleck). The Company also represented to the Commission that if it were to update its responses to Data Requests DIV 1-2 and DIV 13-4 through October 2008, it would show that the gap between budgeted and actual spending is narrowing. NGrid Post-Hearing Reply at 20; Ex. DIV-52. In addition, the Company represented to the Commission that it would not object to an adjustment in the rate year end plant in service amount if the projected capital spending does not occur. *Id*. at 19.

The Commission finds that the Division's position, while reasonable based on the information made available by the Company prior to the hearings, does not account for the lag in contractor billings in the early months of the measuring period, or the non-linear rate of spending on plant additions. The Commission therefore approves the Company's proposed rate year rate base. In the event that the projected capital spending does not occur prior to the end of the rate year, the Company shall notify the Division and make an appropriate adjustment to reflect the actual lower amount of actual plant in service.

B. Operating Expenses (Cost of Service).

1. Health Care Costs.

The Company proposed rate year medical and dental costs of $4,614,000, a 21.4% increase over the test year expense. Ex. NGrid-3 at 18 and Attachment NG-MDL-1 at 8

(Laflamme); Tr. 8/27/08 at 39. The Division reduced rate year health care costs by $907,456 based on seven months of actual data, which suggested that costs would be less than proposed by the Company. Ex. DIV-1 at 5-7 (Effron). The Company disagreed that seven months of data are adequate to calculate costs, but did not challenge the reduction. Tr. 9/8/08 at 84-85 , 101-102 (Laflamme); NGrid Post-Hearing Mem. at 20. The Commission approves the reduction of $907,456.

2. <u>FAS 112 Expense.</u>

FAS 112 relates to post-employment benefits other than pension, such as short term and long term disability benefits and health care costs associated with employees, their dependants and beneficiaries. The Company initially proposed an expense of $912,846. The Division challenged this amount on the grounds that some or all of the proposed expense appeared to be a "catch-up" of non-recurring prior year costs not appropriate to include in the rate base. Ex. DIV-2 at 2 (Effron); Ex. DIV-28 (Data Request DIV 13-2); Commission Record Request No. 5; Tr. 9/8/08 at 89-92, 94-96. At the hearings, the Company developed testimony indicating that a portion of its proposed FAS 112 expense is non-recurring. Tr. 9/8/08 at 91 (Laflamme). The Company revised its proposed FAS 112 expense from $912,846 to $740,000. Tr. 9/8/08 at 89-92, 94-96; Ex. NGrid-4, Attachment NG-MDL Rebuttal 2 at 3; Ex. NGrid-21 (NGrid Response to Data Request DIV 13-3).

The Division's witness agreed that FAS 112 expense is appropriate to include in the revenue requirement "assuming it's a normal, ongoing level of expense." Tr. 9/8/08 at 180 (Effron). The Division states that the proposed downward adjustment to $740,000 "is not unreasonable." Division Post-Hearing Mem. at 21.

The Commission finds that FAS 112 expense is a normal, recurring expense associated with employee benefits, and that the Company has removed any "catch-up" amount

resulting from an error in recording the Company's FAS 112 expense following the Southern Union transaction. The Commission further finds that the Company's estimated FAS 112 expense for FY 2009 is $740,000, which is representative of the expense level that the Company will experience on a going-forward basis.

3. Synergy Savings – Southern Union Merger.

In August 2006, National Grid acquired the Rhode Island operations of New England Gas company from Southern Union. The Company proposed adding $1,054,609 to its cost of service revenue requirement in this docket to reflect the Company's 50 percent share of asserted synergy savings from the merger. The adjustment included $896,971 of shared savings and $157,638 for amortization of costs to achieve. Ex. NGrid-3, Attachment NG-MDL-1; Ex. NGrid-4 at 13 and Attachment NG-MDL Rebuttal 4. The Company proposed including this amount in rates for 10 years. *Id*.

Company Position. The Company measured its proposed merger synergy savings by comparing three categories of corporate expense: employee compensation, administrative and general expense, and corporate office expense. The Company's approach was to look at changes in these categories because the merger did not combine operations. Pre-merger costs were measured during the year ending June 30, 2006. Post-merger costs were measured during the test year, ending September 30, 2007. Ex. NGrid-4, Attachment MDL Rebuttal-4 (calculating total demonstrated savings of $1,951,580); Tr. 9/8/08 at 75-76 (Laflamme).

The Company argues that using the Division's benchmark period (the year ending June 30, 2003) to calculate synergy savings is not appropriate because it does not account for three years of cost increases or decreases before National Grid acquired the business in 2006, for gas sales declines after 2003, or a significant increase in rate base from infrastructure investments. Tr. 9/8/08 at 104-107; Ex. NGrid-4 at 11-12 (Laflamme Rebuttal). The Company

contends that "the record is clear that cost levels in discrete cost categories are reduced from prior levels" after the merger. NGrid Post-Hearing Mem. at 25. The Company disputes that expenses in the year ending June 30, 2006 were unusually high, and asserts that in any event the unusual expenses cited by the Division were in categories (distribution maintenance and uncollectables expense) not relevant to the Company's merger synergy calculation. *Id*. at 26-28, 32-33. The revenue requirement approved in Docket No. 3401 was based in part on a review of anticipated consolidation savings in specific cost categories, and the Docket No. 3401 savings proof was not intended to quantify underlying merger synergies, but only to determine whether shareholders would be entitled to continue to claim 50% of those synergies in a future base rate case. *Id*. at 29-32.

Division Position. The Division argues that the Commission has never reviewed Southern Union's expenses incurred in the year ending June 30, 2006 to determine if they are appropriate for rate-making purposes, and that therefore those expenses should not be used as a benchmark for measuring synergy savings. Division Post-Hearing Mem. at 29; Tr. 9/8/08 at 168-171 (Effron). The Division also expresses reservations about the Company's approach of selecting only certain expense categories for purposes of calculating savings, on the grounds that it was more likely to present the merger in a favorable light than a broad measure of the cost of service. Division Post-Hearing Mem. at 27-28; Tr. 9/8/08 at 103. The Division asserts that the Commission has already approved a method of measuring synergy savings achieved by the former New England Gas Company that broadly measures changes in the cost of service. Using this method, no synergy savings have been demonstrated because the normalized post-acquisition cost of service exceeds the inflation adjusted and normalized benchmark cost of

service for the acquired Rhode Island natural gas operations established in Docket No. 3401 by about $12.4 million. Ex. DIV-1 at 14 (Effron Direct) and Schedule DJE-4.1.

Commission Decision. The Commission in the past has allowed a 50/50 sharing of net merger savings between ratepayers and the Company. The Company realizes its share of the savings by adding them to the cost of service. *See, e.g., New England Gas Company*, Docket No. 3401, Order No. 17381 (2002). The rationale for allowing sharing of synergy savings is that the savings would not exist for customers without shareholders being willing to incur the costs of the merger. Synergy savings are only appropriate, however, when there is an adequate basis for establishing that the savings have been achieved.

The Commission finds that the Company's method of comparing post-transaction cost of service to a pre-transaction cost of service for the twelve months ended June 30, 2006 is not appropriate in this case. The Company's expenses for that pre-transaction period were never approved for inclusion in the base rates, and might not be indicative of a reasonable, normal level of ongoing expenses. The Division presented testimony suggesting that at least some expenses incurred by the Company in its benchmark period ending June 30, 2006 may have been excessive. Tr. 9/8/08 at 170 (Effron). Other evidence supported the Division's position that selecting only certain expense categories to measure synergy savings could present the merger in a more favorable light than a broad measure of expenses: a Company witness testified that an alternative calculation based on a broader measure of expenses would reduce the synergy savings proposed by the Company by approximately $250,000. Ex. NGrid-23 and Tr. 9/8/08 at 111-115.

The Company has the burden of presenting sufficient evidence in support of a requested rate increase. R.I.G.L. § 39-3-12 ("At any hearing involving any proposed increase in any rate, toll or charge, the burden of proof to show that the increase is necessary in order to

obtain a reasonable compensation for the service rendered shall be upon the public utility."). In the absence of additional evidence from the Company supporting the reasonableness of its expenses during its benchmark period, the Commission finds that no National Grid/Southern Union merger synergy savings have been shown.

4. <u>Synergy Savings – KeySpan Merger.</u>

In August 2007, National Grid completed a merger with KeySpan Corporation, resulting in a combined organization serving approximately 3 million natural gas customers in four states. The Company proposed reducing the base rate revenue requirement by $2.45 million to reflect the ratepayer half of anticipated synergy savings from National Grid's acquisition of KeySpan, net of the annual amortization of the cost to achieve. Ex. NGrid-3 at 39-40 (Laflamme Direct); Ex. NGrid-4 at 14-15 (Laflamme Rebuttal). The Company proposed this reduction although it does not expect the full amount of savings to be achieved until the fourth year after the merger.[7] The Company also proposed that it should be allowed to fix its share of the synergy savings in future rate proceedings at the same $2.45 million. The Division accepted the up front synergy savings for ratepayers, but initially proposed that any future synergy savings for the Company be subject to proof. The Company objected to giving the ratepayers up front credit for synergy savings not yet achieved in the rate year ($1.2 million of the $2.45 million), while subjecting the Company to a savings proof. Ex. NGrid-4 at 39 (Laflamme Rebuttal).

At the hearings, the Company and the Division stipulated that merger savings totaling $6.4 million are projected to result from the National Grid/KeySpan transaction, and that the annual amortization of the cost to achieve the merger savings is $1.5 million. The Company and the Division also stipulated that $2.45 million should be included in the base rate revenue

[7] Ratepayers' 50% share of net synergies to be achieved during the rate year is $1.3 million. Ex. NGrid 4 at 14-15 and Attachment MDL Rebuttal 5.

requirement as a credit, to reflect the ratepayers' 50% share of the projected merger synergies net of costs to achieve. Tr. 9/8/08 at 71-72 (Laflamme). The stipulation further provides that the Company will be allowed to include its $2.45 million share of projected merger synergies as a line item in the cost of service in any rate case filed within five years after the Commission's order in this case. Tr. 9/8/08 at 70-73 (Laflamme). In any rate case filed after five years but within ten years, the Company's share of synergy savings from the KeySpan merger will be subject to a savings proof based on a comparison of pre-merger total O&M expense (escalated for inflation) to total rate year O&M proposed in the rate case. The pre-merger total operation and maintenance expenses for this calculation will be the adjusted per book expenses for the twelve months ended September 30, 2007 as reflected in this proceeding. The Company will for ten years be allowed to reflect its share of savings in annual earnings reports filed with the Commission for earnings sharing purposes. The Commission finds that the stipulated synergy savings will provide a direct benefit to ratepayers, and that putting off including the ratepayer share of KeySpan merger synergy savings in the rate base until a future rate case is not in the best interest of the Company's Rhode Island customers. The Commission approves the stipulation.[8]

The Company requested that the Commission allow it to create a regulatory asset in accordance with FAS 71 to account for the levelized amortization costs to achieve over a ten year period to be included in its cost of service. *Id.*, NGrid Post-Hearing Mem. at 36. The Commission finds that a regulatory asset pursuant to FAS 71 is a reasonable step ancillary to the approval of the synergy savings. The Commission approves this request.

---

[8] Commissioner Holbrook dissents from this portion of the Commission's decision and would require that the synergy savings be determined in a separate docket for reasons stated on the record at the November 24, 2008 Open Meeting. Tr. 11/24/08 at 119.

5. **Gas Marketing Program.**

The Company proposed to establish a ratepayer-funded Gas Marketing Program and to include marketing program costs of $1,377,000 in the base revenue requirement: $698,798 for customer rebates and incentives, $528,000 for customer outreach and communication, and $150,000 for program administration. Ex. NGrid-6 at 25-26 (Mongan Direct); Ex. DIV-8 (Data Request DIV 1-20). The Division objected, and proposed an allowed marketing expense of $148,000.

Company Position. The Company states that it is proposing a Gas Marketing Program that will (1) expand the use of natural gas as a cleaner-burning fuel than heating oil alternatives, (2) maintain the overall throughput of the system so that the cost of the system is not carried by fewer and fewer units, and (3) operate at no cost to the system because revenues received from new customers will exceed the cost to add them. NGrid Opening Statement at 30; NGrid Post-Hearing Mem. at 37, 42. The proposed program will target residential and C&I customers located on the existing distribution system who do not use gas, or use only limited quantities (*i.e.*, residential non-heating customers). Ex. NGrid-6 at 4-5 (Mongan Direct). The Company projects 1,950 incremental residential conversions from the program in 2008 and has incorporated approximately $900,000 of revenues from these anticipated new customers in its revenue requirement calculations, as well as $550,000 of incremental rate base expense. Ex. NGrid-7 at 9 (Mongan Rebuttal); Ex. NGrid-6 Attachment SPM-1; Tr. 8/27/08 at 46.

In the Company's view, the Gas Marketing Program is needed to offset customers' up front cost of converting from oil to natural gas. The Company believes that this incremental investment poses a significant obstacle for many customers, regardless of any price differential between oil and natural gas. Ex. NGrid-6 at 10-11; Ex. DIV-17 (Data Request DIV 8-7); NGrid Post-Hearing Mem. at 39-40. The Company anticipates a 400% increase in Rhode

Island oil to gas conversions through the end of fiscal year 2009, resulting from the Gas Marketing Program and the oil/gas price differential. Ex. COMM-1 (Data Request COMM 1-23). This increase is much larger than in the Company's other jurisdictions where rate-funded gas marketing programs have existed for some time. *Id*.

The Company disputes that passing equipment discounts through to is customers, or offering equipment rebates, is discriminatory or anticompetitive. The record shows that the Company is purchasing of equipment in bulk from manufacturers who were the successful bidders in a competitive solicitation and is passing the competitive price made available by the manufacturer to all customers who are interested in procuring their furnace or boiler through the Company. Ex. DIV-3 at 28. The Company is not making any profit on the sale of equipment, nor is it adding any type of markup. *Id.* Moreover, all converting customers are eligible for the equipment rebate, regardless of whether they purchase their equipment through the Gas Marketing Program, or through a third-party plumbing and heating contractor. *Id.* Thus, the Company is purchasing the equipment at a market price following a competitive solicitation; is providing that equipment to converting customers at cost, and is offering equipment rebates to all converting customers on a non-discriminatory basis.

The Company also disputes that its ValuePlus Installer program improperly benefits its unregulated affiliate, National Grid Energy Services ("NGES"). The record shows that the only contact that the Company would have with NGES is through the ValuePlus Installer ("VPI") Program, which occurs because NGES is allowed to participate on the same basis as all other pluming and heating contractors. *Id.* The record shows that out of all the conversions completed through the program, approximately 30 percent utilize a referral through the VPI Program. *Id.* The record also shows that NGES handles only a small percentage (5% on

average) of the total conversions completed in any jurisdiction in which the company conducts the Gas Marketing Program. Thus, there is no record support for the conclusion that the Company's unregulated affiliate would be favored or would unduly benefit from the existence of the Gas Marketing Program.

The Company's internal rate of return calculation for new customers added through the Gas Marketing Program demonstrates that the program will benefit ratepayers by generating returns from new customers that exceed the Company's allowed return on equity. Ex. NGrid-6 at 23-24 (Mongan). The Company produced an internal rate of return calculation demonstrating that the addition of new residential customers through the Gas Marketing Program would produce a rate of return of approximately 14.8 percent, while new C&I customers will produce a rate of return of approximately 21.4 percent. *Id.* at 28. This calculation is significant because it means that, in this case, the Commission will aim to design rates to recover the Company's allowed return on equity but customer additions completed through the program will produce a rate of return in excess of that amount. Ex. NGrid-6 at 21-22 (Mongan). Since the Company is proposing to implement an earnings sharing mechanism to share earnings in excess of the allowed rate of return, customer additions resulting from the program will inure to the direct benefit of existing customers, who are credited with 50 percent of earnings in excess of return on equity and 75 percent of incremental earnings greater than 100 basis points above the allowed 10.5% return on equity.

The Company maintains that the Gas Marketing Program is not prohibited by Rhode Island law because it is designed to encourage gas conversions by (1) extolling the efficiency of gas furnaces and other major home appliances, (2) raising customer awareness regarding the amount of money consumers would save by using newer, efficient equipment

models, (3) providing informational materials that encourage the use of newer and more efficient gas appliances, and (4) encouraging conservation rather than merely promoting the use of gas. NGrid Response to Legal Memorandum on Gas Marketing Program at 15. Even assuming that the customer communications under the Gas Marketing Program are promotional, and therefore prohibited by R.I.G.L. § 39-2-1.2, rebates, discounts and staffing are not direct or indirect costs of advertising, and should be allowed. *Id.* at 16.

Even institutional and branding costs may be allowable, if there is a demonstrated customer benefit. NGrid Response to Legal Memorandum on Gas Marketing Program at 6. The Company has demonstrated that the Gas Marketing Program will directly benefit customers in both the near and long-term. *Id*. at 19, 23-24.

Division Position. The Division argues that the incremental growth in revenues that the Company estimates will arise from the Gas Marketing Program will still be achieved without it. Data for the first eight months of 2008 show 1,617 conversions and upgrades, a nearly 250% increase over the corresponding period in 2007. Ex. DIV-11, Response to Commission Data Request 3-8. Conversions in the first eight months of 2008 exceeded the annual conversions that the Gas Marketing Program seeks to achieve. Ex. NGrid-6, Attachment NG-SPM-1. The expense of the Gas Marketing Program is not necessary. The Company should be permitted to spend only an amount equal to the planned spending of Rhode Island oil dealers, $148,000. Ex. DIV-3 at 27 (Oliver).

The Division disputes the argument that the cost of adding the new customers targeted by the Gas Marketing Program exceeds the incremental revenue. The Company has focused its marketing effort on customers located near existing distribution mains. Because distribution mains represent the largest element of the Company's rate base, new customers who

do not require additions to distribution mains can be added to the system at less than the average cost on which rates will be based. Division Post-Hearing Mem. at 22.

The Division also argues that the Gas Marketing Program would result in ratepayer funds being used to benefit the Company's unregulated affiliate, National Grid Energy Services. National Grid Energy Services performs oil to gas conversions in competition with other plumbing and heating contractors. Tr. 10/20/08 at 201-04 (Mongan). The Company's practice is to refer customer conversion inquiries to contractors on its Value Plus Installer list, including National Grid Energy Services; therefore, increasing the number of oil to gas conversions directly benefits National Grid Energy Services along with other conversion contractors. To date, National Grid Energy Services has performed only a small percentage of all residential conversions in Rhode Island. The Division asserts that over time the unregulated affiliate will become the dominant beneficiary of the marketing expenses being paid by ratepayers.

The Division also argues that the Company launched the Gas Marketing Program with its own funds earlier this year, and is likely to continue it even without explicit cost recovery through rates. Current economic conditions argue against an increased rate burden for an unnecessary program. Furthermore, the program arguably violates R.I.G.L. § 39-2-1.2 because it is designed to promote the consumption of natural gas. Division Post-Hearing Mem. at 25-26.

Attorney General Position. The Rhode Island Attorney General states that the proposed Gas Marketing Program is prohibited by G.L. § 39-2-1.2(a), which does not allow expenses in the Company's rate base for "advertising, either direct or indirect, which promotes the use of its product or service, or is designed to promote the public image of the industry."

Advertising under the statute includes all forms of promotional media, as well as promotional activities including discounts, rebates, and sales administration. The Commission has disallowed promotional, goodwill and institutional advertising expenses, including labor expenses, in prior dockets. RIAG Post-Hearing Mem. at 2-7.

The Gas Marketing Program does not qualify for the statutory exemption allowing advertising "informational or educational in nature, which is designed to promote public safety and conservation of the public utility's product or service." R.I.G.L. § 39-1-1.2(a). Each component of the program promotes use of natural gas. RIAG Post-Hearing Mem. at 9-13; Ex. NGrid 6; Ex. AG-3; Tr. 10/23/08 at 163-173 (Oliver); Tr. 10/20/08 at 194-95 (Mongan).

The customer outreach and education component of the Program consists of a concerted marketing effort to convince a target set of potential customers to convert to natural gas over their existing "energy choice." Ex. NGrid-6 at 8-9, 11. Through direct mailings, radio, and visual media, etc., the Company represents to customers that they can "save money" (because gas is more "efficient" than oil) and "save space" (by "saying good-bye" to your old oil tank and the "soot, fumes, and sulfur dioxide" of oil). *See, e.g.* Ex. AG-3 at 3, 12, 18, 20, 22. The Company also represents that customers can "find help" locating a "qualified" contractor through the Company's VPI Program and earn "valuable rebates . . . up to $1,500 on heating equipment," a $1,500 discount "that'll make your [the customer's] wallet happier too." *See, e.g.*, Ex. AG-3 at 11-12, 15-16, 18. The stated purpose of these communications is to "identify potential conversion candidates" and to "pass those contacts on to local plumbing and heating contractors" participating in the Company's VPI program. Ex. NGrid-6 at 15-16.

The Program's customer outreach and education component is not tailored merely to inform customers about the benefits of natural gas in terms of efficiency and conservation.

Rather, the component functions to identify, and then to steer target customers who do not have relationships with contractors towards contractors who will convert their system(s) to natural gas (*e.g.*, typically an "on-main conversion or low-use upgrade") from the customers' existing energy sources. Ex. NGrid-6 at 16. The component, therefore, is purely promotional in nature.

Substantially all of the testimony in the record supports this conclusion. Mr. Mongan acknowledged that the direct mail materials that the Company forwarded to its customers in connection with the Program in late 2007 and early 2008 promote natural gas over oil in multiple ways: (i) by intimating that customers waste .30 of every dollar in oil heat; (ii) by invoking fears that with oil comes the ever-present worry of a leaky tank; (iii) by implying that purchasing natural gas (rather than oil) is more patriotic because 97.3% of it as opposed to 56% for oil "comes from North America;" and (iv) by stating that burning oil inevitably produces "fumes" and "greenhouse gases" that are not associated with natural gas. Tr. 10/20/08 at 195-197.

The second component of the Program – installation support and associated labor ($150,000) – violates § 39-2-1.2(a) for a similar reason. The VPI Program is a "contractor-referral system" that seeks "to facilitate the Company's efforts to increase system utilization in a cost-effective manner through low-use upgrades and on-main conversions," Ex. NGrid-6 at 17, and specifically, is designated to "create a high level of customer satisfaction and convenience," facilitating the Company's effort to "increase system utilization." Ex. NGrid-6 at 17. The principal aim of the VPI Program and associated incremental labor, is to promote natural gas over customers' existing energy sources and to promote the public image of natural gas.

The record evidence supports this conclusion. Mr. Oliver testified that in his expert opinion the VPI Program is promotional. Tr. 10/23/08 at 173. Mr. Mongan confirmed

that the Company had engaged an "in bound inquiry rep" as well as an "inside sales rep" to handle all conversion related calls. Tr. 10/20/08 at 194. Customers that require contractors are steered to the VPI network. Tr. 10/20/08 at 194-195. This serves the promotional aim of the gas marketing program: to facilitate customer conversions from other energy sources to natural gas. Tr. 10/20/08 at 194-195.

The equipment discount and rebate components of the Program also serve to promote the use of gas over customers' existing sources of energy. Ex. NGrid-6 at 18-19. Under the third component of the Program (equipment discounts), "purchased equipment is offered to customers . . . at a price that reflects both the Company's bulk-purchase discount and also a further discount made available through the [Program] to enable customer conversions to gas service." Ex. NGrid-6 at 18. "Because the cost of gas conversion can be higher than other fuel options available to the customer, the combination of the bulk purchasing discount and the program discount provide a valuable incentive to customers" to enable them to switch to gas service from their existing energy source. Ex. NGrid-6 at 18.

The same is true for equipment rebates – the fourth component of the Program. "Customers who would prefer to purchase gas-heating equipment from a manufacturer that is not part of the Company's bulk purchasing program" are "eligible for a rebate of equal value to the program discount offered on equipment purchased by the Company from its manufacturing suppliers." Ex. NGrid-6 at 18. This ensures that customers are able to obtain the same program incentive – the elimination of "incremental costs" – that "must be overcome in order to motivate new gas conversions." Ex. NGrid-6 at 19.

Most, if not all of the evidence on the record, corroborates the promotional nature of equipment discounts and rebates. Mr. Oliver testified that in his expert opinion, the rebates and discounts associated with the Program are promotional in nature:

> Q. Do you believe that those other components, . . . the rebates and discounts, that those have a characteristic that would advance one energy source over another?
>
> A. They tend to, yes.

Tr. 10/23/08 at 173. The equipment rebates and discounts, moreover, are directly marketed to customers in the customer outreach and education component of the Program. Tr. 10/20/08 at 197. Without the rebates and discounts, the other promotional components of the Program would not, and could not, function. Tr. 10/20/08 at 247-48.

The Company has not provided any analysis of the internal rate of return of the Gas Marketing Program in the absence of the price differential between oil and gas. The record supports the conclusion that the increase in conversions is the result of this price differential, not the Company's marketing program. The customer outreach and education component of the Program commenced in the last quarter of 2007. Ex. AG-3 at 1. For the first quarter of 2008, the Company completed 628 residential conversions – which the Company concedes "is a greater number of conversions than experienced in the past for the same period." Ex. NGrid-7 at 9. The Company projects 1,950 incremental residential conversions in 2008, all the while conceding that during this time period natural gas has enjoyed and continues to enjoy a substantial price differential advantage as compared with oil – a differential which "is currently motivating some customers to commence the conversion process . . . ." Ex. NGrid-7 at 11. The Company concedes, moreover, that many (but not all of) the conversions to date can be attributed to the cost differential and not the Program. Ex. NGrid-7 at 10; *see also* Tr. 10/23/08 at 160-61 (Oliver) (price differentials "very strongly suggest that not only today but in the long

run heating with natural gas would be a preferred alternative"). Therefore there is no clear evidence to show that the program will provide a direct ratepayer benefit, which in some other jurisdictions (but not Rhode Island) might justify the expense. RIAG Post-Hearing Mem. at 14-16.

The proposed program would be detrimental to ratepayers because (1) they would be paying the cost of identifying conversion opportunities for the Company's unregulated affiliate, (2) they would be funding the inside inquiry and sales representative activities that benefit the unregulated affiliate, and (3) they would pay for equipment discounts and rebates afforded to customers of the unregulated affiliate, without any contribution from the unregulated affiliate. RIAG Post-Hearing Mem. at 16-19.

Commission Decision. Regardless of the alleged economic, environmental or customer benefits of the proposed Gas Marketing Program, it must comply with Rhode Island law. In Rhode Island, base rates may not include a utility's expenses for "advertising, either direct or indirect, which promotes the use of its product or service, or is designed to promote the public image of the industry." R.I.G.L. § 39-2-1.2(a). The Commission has disallowed promotional, goodwill and institutional advertising expenses, including promotion-related labor expenses, in prior dockets. *See, e.g.*, *Tariff Filing Made by the Providence Gas Company on February 16, 1995*, Docket No. 2286, Order No. 14589 (1995) (allowing informational expenses but disallowing promotional, goodwill and advertising expenses of $457,000); *Valley Gas Co. v. Burke*, 518 A.2d 1363, 1366 (R.I. 1986) (upholding Commission decision to approve informational advertising expenses and deny promotional advertising expenses). Advertising expenses are allowable only for advertising that is "informational or educational in nature, which

is designed to promote public safety and conservation of the public utility's product or service." R.I.G.L. § 39-1-1.2(a).

The Commission finds that the evidence presented in this docket demonstrates that the Company's Gas Marketing Program promotes the use of natural gas, contrary to R.I.G.L. § 39-2-1.2(a). Company testimony expressly linked the marketing program to increased gas consumption by existing low-use customers or new customers near existing distribution lines. For example, one Company witness stated:

> The basic objective of the Company's Gas Marketing Program is to encourage cost-effective, increased system utilization through conversions of new and existing low-use customers to gas service.

Ex. NGrid-8 at 4 (Mongan Direct); *see also id*. at 13 ("the Gas Marketing Program is targeted at motivating conversions to gas service . . . ."). The record also reflects that the Gas Marketing Program will benefit the Company's unregulated affiliate, National Grid Energy Services, by generating sales leads that will be shared with National Grid Energy Services along with other contractors participating in the Value Plus Installer program. Tr. 10/20/08 at 199, 235-236 (Mongan).

The Company's arguments that the Gas Marketing Program should be allowed because it entails advertising "informational or educational in nature, which is designed to promote public safety and conservation of the public utility's product or service," R.I.G.L. § 39-1-1.2(a), are not persuasive. It is unusual for gas distribution companies to market conversions with ratepayer funds, Tr. 10/21/08 at 144 (Oliver), and the Commission sees no basis to extend the definition of "informational or educational" activities to include activities aimed primarily at adding new natural gas customers to the distribution system. The Company launched the program with its own funds earlier this year, Tr. 10/22/08 at 60-61 (Stavropoulos), and

anticipates that it will produce high internal rates of return. Tr. 10/20/08 at 142 (Mongan). Current economic conditions argue against an increased rate burden for marketing efforts that were sufficiently beneficial to the Company that they were initiated without a ratepayer contribution.

The Commission further finds that the incremental rate year sales that the Company has estimated will be produced by the Gas Marketing Program should not be eliminated. Data for the first eight months of 2008 show conversions up nearly 250% over the corresponding period in 2007. Ex. DIV-11, Response to Commission Data Request 3-8. The Division presented testimony that over time, natural gas will hold a significant price advantage over oil that will encourage conversions. Tr. 10/21/08 at 66-72; Ex. DIV-3 at 20-21 (Oliver). This evidence supports the conclusion that the Company's estimated sales growth from conversions will be achieved even without a ratepayer funded Gas Marketing Program.

6. <u>Uncollectible Expense.</u>

The Division proposed reducing the Company's uncollectible accounts receivable expense of $3,594,522 by 50% of the cost of the proposed low income discount, or $415,000, if the proposed low income discount were adopted by the Commission. The Division presented testimony linking the proposed discount to a reduction in uncollectible accounts. Ex. DIV-3 at 72 (Oliver) ("This recognizes that a large portion of the [low income] discount amounts would likely become future uncollectible accounts expenses in the absence of the offered discounts, and it shares the risks associated with the effectiveness of those discounts between the Company and its ratepayers.").

The Company does not gather information from which it can determine the actual uncollectible rate for low income customers. However, the Company disputed that any link exists and presented evidence that uncollectible accounts for electric service have increased

notwithstanding a low income discount for electric ratepayers. Ex. NGrid-4 at 8-9 (Laflamme Rebuttal); Tr. 9/8/08 at 98-101 (Laflamme).

At the hearings, the Division and the Company stipulated that in the event the Commission approved a low income discount (of any size), uncollectible expense would be reduced by $150,000. Tr. 9/11/08 at 175-176 (Czekanski); Division Post-Hearing Mem. at 30. The Commission approves the stipulated $150,000 reduction.

7. <u>Rate Case Expense.</u>

The Company proposed that rate case expenses for the Company, the Division and the Commission be allowed through base rates, amortized over three years. NGrid Post-Hearing Mem. at 45. The record reflects that that Company will incur rate case expenses totaling $884,481; the Division will incur rate case expenses totaling $113,075; and the Commission will incur rate case expenses of $350,887; for a total rate case expense of $1,348,443. NGrid Response to Commission Post-Hearing Data Request Set 1; Division Response to Commission Post-Hearing Data Request Set 1; Tr. 11/24/08 at 93-94. The Commission finds that rate case expenses are a necessary cost for the Company and recovery of reasonable rate case expenses is allowed through base rates under the Commission's precedent. The Commission further finds that the expenses of the Company, the Division and the Commission are reasonable in light of the scope, complexity and novel policy issues of this contested rate case, as reflected in the voluminous record and lengthy public hearings. The Company shall be allowed to recover its updated rate case expenses, including the Division's and Commission's expenses, amortized over a three year period, or $449,481 per year.

8. <u>Encroachment Expense.</u>

The Company's pro forma rate year expenses included $1,054,000 for additional operation and maintenance expenses relating to encroachment by increased public works

activities and third party excavations. Part of the increased expenses were based on the backlog of work existing in early 2008, and part were based on anticipated new encroachments. Ex. DIV-12 (Division Data Request 4-10). After reviewing the Company's actual encroachment expenses for the five months ending February 2008, the Division concluded that the rate of encroachment spending was well below the level reflected in the Company's pro forma rate year expenses and recommended a reduction of $756,000. Ex. DIV-1 at 9 (Effron). The Company accepted this recommendation. Division Post-Hearing Mem. at 27. The Commission approves the $756,000 reduction to the Company's pro forma test year operation and maintenance expense for encroachments, to $298,000.

9. Distribution Maintenance.

The company incurred actual distribution maintenance expenses of $16,804,000 in the test year. However, these expenses included costs incurred to reduce the backlog of Grade 2 gas leak repair work and paving restoration work arising before the beginning of the test year. Ex. DIV-1 at 10 (Effron); Ex. DIV-8 (Division Data Request 1-28); Ex. DIV-18 (Division Data Request 9-3); Ex. DIV-18 (Division Data Request 9-4). The Division concluded that the increased test year distribution maintenance expenses related to the backlog reduction were not continuing expenses, and recommended a reduction of $539,000 to the Company's pro forma test year operation and maintenance expense for distribution maintenance. Ex. DIV-1 at 11 (Effron). The Company accepted this position. Ex. NGrid-4, Attachment NG-MDL Rebuttal 1. The Commission approves the $539,000 reduction, and allows $16,265,000.

C. Revenue Reconciliation Proposals

1. Accelerated Capital Replacement Program

The Company proposed an accelerated replacement program ("ARP") to make upgrades to targeted portions of its delivery system. More specifically, the ARP will remove all

high pressure, bare-steel services from inside customer premises within five years. Tr. 9/9/08 at 42-44 (Fleck). The ARP will increase the amount of bare steel mains replaced annually, from 7.5 to 18 miles. Tr. 9/9/08 at 42-44 (Fleck). The Company also proposed to replace small-diameter cast iron mains on a more systematic basis. Ex. NGrid-5 at 17-21 and Attachment NG-SLF-1 (Fleck).

The Company initially proposed that the total cost of main replacement be funded through a reconciling mechanism. The Division objected that only the incremental cost of the accelerated replacement program, above pipeline replacement costs that would be incurred in the ordinary course, should be reconciled. The Company accepted this change. Ex. NGrid-4 at 17-18 (Laflamme Rebuttal); Tr. 9/8/08 at 78-83. The Company also agreed to limit upward rate adjustments for the accelerated replacement program if the Company's earnings are at or above its approved return on investment. *Id*. The Company states that its planned incremental spending is about $12 million, out of about $25 million total spending planned. Ex. NGrid-4, Attachment NG-MDL Rebuttal 6; Tr. 9/8/08 at 149-151 (Laflamme).

Company Position. The Company distributes natural gas to approximately 250,000 Rhode Island customers through a distribution infrastructure that includes approximately 900 miles of cast iron main, 440 miles of unprotected bare steel main and 240 miles of unprotected coated steel main out of a total 3,100 miles of main. Ex. NGrid-5 at 4, 15-16 (Fleck); Tr. 9/9/08 at 6-7 (Fleck); Ex. COMM-3 (Data Request COMM 2-7). Approximately 50% of the Company's Rhode Island distribution assets are leak prone, and the number of gas leaks is increasing. Since 2005, there have been over 1,400 gas leaks per year in the system, more than 50% higher than the leak rate of 900 per year for 1991-2004. Ex. NGrid-5 at 15-16 (Fleck). The leak rate has increased in spite of the fact that the Company and its predecessors

have replaced almost 120 miles of bare and unprotected coated steel mains in the last ten years. *Id*. The number of leaks per mile is higher in Rhode Island than in other jurisdictions where the Company operates. Ex. NGrid-5 at 16 (Fleck). For example, leakage rates in Rhode Island are more than seven times higher than in upstate New York. Tr. 9/9/08 at 73 (Fleck).

The Company has conducted a baseline assessment of its distribution assets and determined that at current replacement rates, continual system degradation from corrosion will undermine its ability to meet demand and operate the system safely and reliably. Ex. NGrid-5 at 16 (Fleck). The Company therefore proposed an accelerated replacement program ("ARP") to make upgrades to additional sections of its delivery system, selected based on such factors as the age and condition of the pipe, geographic location and expected growth in system demand. Ex. NGrid-5 at 17 (Fleck). The Company anticipates that its accelerated replacement plan will cause the number of gas leaks to begin to decline. A declining number of gas leaks is a reasonable measure of overall system safety and is the Company's goal. Tr. 9/9/08 at 26 (Fleck).

The Company also proposed removing all high pressure, bare-steel services from inside customer premises within five years. Approximately 8,261 such services exist today, which historically have been replaced at a rate of approximately 500 per year. The Company plans to accelerate the removal rate to approximately 1,600 units per year. Ex. NGrid-5 at 21 (Fleck). High pressure bare steel inside services need to be replaced because of the risk of corrosion where the high pressure gas line passes through the wall into the customer's basement. There is no way to inspect that part of the high pressure pipe. *Id*.; Tr. 9/9/08 at 141 (Ledversis). A survey conducted in the Company's Long Island territory demonstrated there is a resulting potential for failure and leaks. Tr. 9/9/08 at 43-48 (Fleck).

The incremental cost of the ARP, above pipeline replacement costs that would be incurred by the Company in the ordinary course, will be funded through a reconciling mechanism. The Company's planned incremental spending on the ARP is about $12 million , out of about $25 million total main replacement spending planned. Ex. NGrid-4, NG MDL Rebuttal 6; Tr. 9/8/08 at 149-151 (Laflamme). The incremental expense being proposed by the Company is based on safety concerns, not economic considerations. Tr. 9/9/08 at 164 (Laflamme).

Division Position. The Division supports the ARP in light of the documented growth in gas leaks in the distribution system, Tr. 9/9/08 at 135 (Ledversis), but suggests that (1) depreciation expense reductions related to ARP related plant retirements should be recognized; (2) the depreciation rate of mains and services, not the average composite rate, should be used to calculate incremental depreciation expense; (3) the calculation of incremental property tax expense should be modified so that it is based on the prior year's annual property tax expense to net plant in service; (4) the mechanism should apply to accelerated replacements, not routine replacements; and (5) there should be no rate adjustment if the Company is earning at or above its authorized return on equity. The Company has agreed to these modifications. Ex. NGrid-4 (Laflamme Rebuttal testimony at 17-18); NGrid Post-hearing Mem. at 49.

Commission Decision. The Commission finds that gas leaks create undesirable safety and environmental issues, and increase costs for ratepayers on account of lost commodity. Tr. 9/9/08 at 164 (Laflamme). The record reflects that historic pipeline replacement rates are not keeping pace with Rhode Island's aging gas distribution infrastructure, and that accelerated infrastructure replacement is in the interest of the ratepayers and the public as a whole. Ex. NGrid-5 at 16 (Fleck) (Rhode Island leaks per mile are increasing and are higher than in other

Company jurisdictions); Tr. 9/9/08 at 73 (Fleck). The Company's proposed increase in the annual replacement of distribution mains and its five year plan to remove high pressure inside services reasonably balances the need to measurably improve the safety and reliability of the Rhode Island natural gas distribution system in the near term against the burden to ratepayers of increased rates to pay for accelerated replacement. A reconciling mechanism is appropriate for the substantial incremental cost of the Company's proposed infrastructure improvements.

The Commission therefore authorizes the Company to implement the ARP, subject to the modifications recommended by the Division. Beginning in January 2009, the Company will submit a proposed implementation schedule to the Division each January for comment, and secure Commission approval. The Company will also submit a reconciliation report for each fiscal year. The first ARP reconciliation report for the 12 months ending March 31, 2009 will be submitted by May 15, 2009 for a rate adjustment effective July 1, 2009. The ARP will entitle the Company to a rate adjustment only to the extent of the capital cost that is incremental to the amount included in base rates in this proceeding. Tr. 9/8/08 at 79-83, 152-153 (Laflamme).

2. <u>Gas Supply Related Bad Debt Cost.</u>

The Company proposed to increase the portion of commodity cost bad debt embedded in the rate base from 2.1% to 2.46%, based on a five year average. Tr. 9/8/08 at 122-123 (Laflamme). The Company also proposed to recover or return any variance from the uncollectible ratio fixed in base rates through the GCR on a reconciling basis. Anticipated commodity related bad debt is currently fixed in base rates.

<u>Company Position</u>. Commodity bad debt is a component of the gas cost that should be recovered on a pass-through basis, as is the cost of the commodity itself. The change in policy will be beneficial to customers because the current structure locks in relatively higher

bad-debt recovery ratios, as well as relatively lower ratios, depending on circumstances at the time of a base-rate filing. Tr. 9/8/08 at 121-123 (Laflamme). The reconciliation would be based on the most recent five year average for net bad debt write-offs as of June 30 of each year. *Id*.; Ex. NGrid-15 at 13. Because the reconciling mechanism would apply only to bad debt related to commodity costs, and not bad debt related to distribution costs, the Company would still have a strong incentive to improve the uncollectible ratio. *Id*.

Division Position. The Division opposes a bad debt reconciliation mechanism because annual reconciliation would amplify price volatility for customers. Ex. DIV-3 at 79 (Oliver). The Commission has historically used a multi-year average of the Company's actual experience in base rates in order to mitigate year to year variations. Division Post-Hearing Mem. at 44; Ex. DIV-3 at 74-75, 79 (Oliver).

Commission Decision. The Commission finds that a bad debt ratio of 2.46% for base rates is supported by the record. The Commission declines, however, to approve the proposed gas cost-related bad debt reconciling mechanism. The Commission has historically used a multi-year average of the Company's actual experience in base rates in order to mitigate year to year variations, and finds that annual reconciliation of commodity-related bad debt cost is not in the best interest of ratepayers because it has the potential to amplify price volatility for customers. Ex. DIV-3 at 74-75, 79 (Oliver). Fixing the commodity-related bad debt ratio in base rates is not inconsistent with the Commission's treatment of commodity costs, which are recovered on a pass-through basis, because the Company has the ability to develop and implement measures to lower the uncollectible ratio.

3. **Reconciliation of Pension and PBOP**

The Company proposes to reconcile its pension and post-retirement benefits other than pension ("PBOP") expenses annually, and to adjust charges to ratepayers up or down accordingly to recover or return amounts above or below actual costs.

Company Position. Pension and PBOP expenses are volatile and beyond the Company's control because they respond to actuarial assumptions and financial market performance. They should be reconciled annually for several reasons.

First, a reconciliation mechanism will not reduce the Company's incentive to control benefit costs. The record shows that the principal alternative for reducing pension costs is the establishment of a defined contribution plan to replace the historical defined benefit plan. Tr. 9/8/08, at 138-139, 249. The record also shows that the Company has already taken steps to reduce pension costs that are within its control by preventing new employees hired after 2002 from entering into defined benefit pension plans. *Id.* at 139. Specifically, on January 1, 2005, all non-union new hires were placed in the Valley Gas pension plan design, which had a less generous formula for its participants. Ex. DIV-15 (Data Request DIV-6-22). Also, on January 1, 2005, post-retirement dental coverage for future non-union retirees was eliminated. Since National Grid's acquisition of the regulated gas operations in Rhode Island in August 2006, all non-union new hires were placed in the National Grid cash balance pension plan. *Id.* Lastly, effective March 31, 2008, all non-union employees that were covered under the Valley Gas or the Providence pension plan designs were transferred into the National Grid Final Average Pay pension plan. *Id.* Lastly, the Company has established an annual review process for pensions and PBOPs centering on: (a) actuarial assumptions, (b) vendor performance, and (c) medicare prescription drug program refund administration. *Id*. There is no basis to conclude that a reconciliation mechanism for pension and PBOP expenses will deter the Company from

continuing to make efforts to control the costs of these benefits and the Company has already made the change identified as the most significant opportunity for reducing costs, which is the transition from a defined benefit to defined contribution plan.

Second, the Company has demonstrated that the magnitude of pension expense as compared to the overall revenue requirement is great enough to warrant reconciliation. The pension and PBOP expense will account for approximately 6.4% of the Company's overall proposed revenue requirement of $150 million. Ex. NGrid-4, at 20. Contrary to the Division's assertions, this is a significant amount of expense for the Company to manage and it is as yet unclear what the impact of current market conditions will be on the pension and PBOP trust fund balances and resulting liability.

Third, the Company has demonstrated that the level of volatility for pension and PBOP is greater than other O&M expenses. Pension/PBOP expense and funding is subject not only to variation from year-to-year, but also is susceptible to periods of extraordinary fluctuation as a result of circumstances in the financial markets, which have been experienced in the recent years. Ex. NGrid-4, at 21. Fluctuations in the value of pension assets cause variations in pension and PBOP expense and funding levels. These volatile fluctuations are due to the stock market and are similar to the wild fluctuations in commodity prices like gas. In fact, both fluctuations in stock market prices and gas prices are beyond the control of the Company. Tr. 9/8/08 at 223-224. As an example of the volatility, contributions to the pension fund increased from $1,350,000 for the plan year ended December 31, 2002 to $2,858,158 for the plan year ended December 31, 2003 and totaled $5,388,000 for the plan year ended March 31, 2008. Ex. DIV-8 (Data Request DIV-1-8). For PBOP, information regarding funding, if any, is unavailable for the years under Southern Union ownership from 2003 through 2007, but the record shows

that National Grid made a contribution of $4,307,000 for the fiscal year ended March 31, 2008. Ex. DIV-8 (Data Request DIV-1-9). Thus, pension and PBOP expenses and funding can change dramatically from one year to another.

Fourth, the amount of pension and PBOP expense included in rates is not calculated to provide adequate funding without the need for a reconciliation mechanism. Fluctuations in the value of pension assets resulting from stock market changes leads to variations in pension and PBOP expense and funding levels. As a result, it is extremely difficult to establish a representative amount of expense in rates, especially where circumstances are occurring in the financial market that will impact the pension and PBOP plans beyond what is included in the expense levels that would be included in rates in this proceeding without a reconciling mechanism. In that regard, the present approach to funding pensions and PBOP creates a potential mismatch of what is embedded in rates for the FAS 87 and FAS 106 expense and what is actually contributed to the pension and PBOP funds. For example, for fiscal year ended June 30, 2004, $6,263,958 was expensed but only $3,626,754 was required for contribution by Southern Union for the plan year ended December 31, 2004. *Id*.

To ensure adequate funding of the pension fund and the PBOP in the future, a fully reconciling mechanism is the best approach because under the operation of the proposed mechanism it would assure that whatever the Company recovers from customers for FAS 87 or FAS 106 is actually contributed to the pension and the PBOP funds or reserved for in order to provide customers with an equitable economic benefit. Ex. NGrid-4 at 23. Without a reconciliation mechanism, there will inevitably arise a situation when the Company is recovering pensions and PBOP costs in base rates and contributing to the funds at a different level. *Id* at 24. Thus, a reconciliation mechanism will ensure that the Company funds the pension and PBOP

funds at the same level as amounts collected from customers. *Id.* Otherwise, there will be occasions when the Company will collect more in rates than it is required to contribute for pension and PBOP or the reverse.

It should also be noted that the proposed reconciliation mechanism for pension and PBOP is consistent with the Commission's recent directive in new England Gas Company, Docket No. 3690, Order No. 18780, which stated that "it is the long-term interest of ratepayers to have a properly funded pension fund." In that case, the Commission noted the mismatch between contributions to the pension fund and what is expensed for pensions over a number of years under New England Gas, and stated that this "difference . . . could be harmful to the pension fund in the long tem." A reconciliation mechanism is the best solution to this mismatch. Not surprisingly, in response to a question from the Commission concerning the possibility of an unfunded pension liability growing under the current rate structure, the Division's witness acknowledged: "[t]hat's the funding mechanism." Tr. 9/8/08 at 236-237. A reconciliation mechanism is the best funding mechanism to avoid an unfunded liability from growing for pension or PBOP.

Division Position. Reconciliation mechanisms are generally contrary to sound ratemaking principles, except for costs with large fluctuations beyond the Company's control that jeopardize its financial integrity. The Company has not presented evidence of the volatility of its pension and PBOP costs, or shown the potential of such costs to impair its financial integrity. Almost all other expenses in the Company's base cost of service are also subject to fluctuation. Division Post-Hearing Mem. at 30-31. Pension and PBOP expenses should be treated differently than GCR because gas costs are comparatively far greater, and therefore pose a far greater risk of a substantial under-recovery. Tr. 9/8/08 at 216-17, 221-24 (Effron).

Reconciliation is not needed to provide adequate funding for pensions and PBOP. Expense accruals are already calculated to provide adequate funding of the programs, even without a reconciliation mechanism. The pension program is currently 97% funded. Tr. 9/8/08 at 142 (Laflamme). This shows that the current method of regulation has not resulted in inadequate funding, and that annual reconciliation of pension and PBOP expense is not necessary. Tr. 9/8/08 at 245 (Effron).

Authorizing annual reconciliation would shift risk to the ratepayers. Tr. 9/8/08 at 217 (Effron). It also would reduce the Company's incentive prudently to manage its PBOP expenses. The Company has moved to reduce pension expense by instituting a defined contribution plan for new employees and making other changes. Tr. 9/8/08 at 139-140 (Laflamme); Ex. DIV-15, NGrid Response to Division Data Request 6-22. The Division questions whether the Company would have undertaken these pension cost control measures if a pension and PBOP cost reconciliation mechanism had been in place. Division Post-Hearing Mem. at 33.

Commission Decision. While the Commission in general disfavors reconciliation mechanisms, they have been approved in the past for certain items. For example, the Company recovers its commodity costs through a reconciliation mechanism. The Commission has also approved a reconciliation mechanism for unpredictable and potentially costly environmental remediation measures. Ex. NGrid-4 at 22 (Laflamme Rebuttal). While not as large as commodity costs, the Commission finds that the Company's pension and PBOP expenses are sufficiently large and unpredictable to justify an annual reconciliation mechanism. The record reflects that these expenses can be subject to substantial fluctuations as a result of changes in the

financial markets that affect pension asset values, and that these fluctuations are beyond the Company's control. Ex. NGrid-4 at 21 (Laflamme Rebuttal).

The Company's pension program is currently 97% funded. Tr. 9/8/08 at 142 (Laflamme). However, the record suggests that under the current methodology, its predecessor, Southern Union, may have funded pensions at the minimum tax deductible level rather than contributing the full amount approved in rates. Tr. 9/8/08 at 135 (Laflamme). For the fiscal year ended June 30, 2004, $6,263,958 was expensed but only $3,626,754 was required for Southern Union's contribution for the plan year ended December 31, 2004. Ex. DIV-8 (Data Request DIV 1-9); NGrid Post-Hearing Mem. at 56. A reconciling mechanism will give ratepayers greater assurance that the Company is funding pension and PBOP funds at the same level as amounts collected from customers.

Under the Company's proposal, ratepayers would assume the risk of investment losses currently borne by shareholders. Tr. 9/8/08 at 136-137 (Laflamme). However, since 2002, new Company employees have been placed in a defined contribution plan, mitigating this risk. *Id.* at 139-140; Ex. DIV-15, NGrid Response to Division Data Request 6-22. The Company has also taken other steps to reduce future pension and other benefit expense, including placing employees in less generous plans and eliminating post-retirement dental coverage for future non-union retirees. Ex. DIV-15 (Data Request DIV 6-22). The Company plans to make further efforts to control pension and PBOP costs regardless of whether the reconciling mechanism is approved: for example, the Company has established an annual review process for pensions and PBOP expenses to assess actuarial assumptions, vendor performance and medicare prescription drug program refund administration. *Id.*; NGrid Post-Hearing Mem. at 53-54; ; Tr. 9/8/08 at 147-148 (Laflamme). Therefore, the Company's exposure to pension

investment losses has been reduced in recent years, and the proposed reconciling mechanism does not create unreasonable new risks for ratepayers.

Reasonable pension and PBOP expenses are legitimate and unavoidable costs of operating the distribution system. To the extent that fixing pension and PBOP expenses in the base rates leads over time to the pension being underfunded, current ratepayers are effectively shifting greater pension and PBOP expense to future ratepayers. The Company's proposed reconciliation mechanism more closely matches present rates with present pension and PBOP expense, and is in the interest of ratepayers. The Commission approves the Company's proposed pension and PBOP mechanism.[9]

D. Revenue Decoupling

The Company's filing proposed to implement for the first time in Rhode Island a full revenue decoupling mechanism ("RDM"). As initially proposed, the RDM applied to all firm rate classes, with certain exemptions for new large customers. Ex. NGrid-12 at 2-7 (Simpson). The Company thereafter modified its proposal to exempt the four large and extra large firm rate classes. Tr. 9/12/08 at 5-6. Low income customers were subsequently excluded as well. Tr. 10/22/09 at 8-11; NGrid Post-Hearing Mem. at 62-63. The remaining classes (residential non-heating, residential heating, small C&I and medium C&I) include most of the Company's customers and generate more than 80% of the Company's distribution revenue. Ex. NGRid 15 Appendix NG-PCC-3; Tr. 9/26/08 at 167-168.

The RDM would set a target revenue per customer amount for customers in the affected classes. The target revenue per customer would be set at an amount sufficient for the Company to recover the base rate revenue requirement for that customer class approved in this

[9] Commissioner Bray dissents from this decision and would adopt the Division's position for reasons stated on the record at the November 24, 2008 Open Meeting. Tr. 11/24/08 at 78-80.

rate case. To the extent actual revenue per customer in the affected classes exceeded or fell short of the target, the surplus or shortfall would be credited or collected through an annual adjustment of the DAC.

The Company's decoupling proposal generated substantial briefing and testimony at the hearings from the parties and intervenors. The principal arguments presented for and against decoupling are summarized below.

Company Position. The Company argues that decoupling will "eliminate the Company's dependence on gas consumption to obtain necessary revenues to run the business," and will "allow [it] to aggressively promote conservation through new energy efficiency, without harming revenues." Company Opening Statement, at 29. Natural gas usage per customer has steadily declined, and the declines are expected to continue. Ex. NGrid-12 at 15-17 (Simpson). Because of declining usage per customer, the Company asserts that traditional ratemaking no longer works. Declining usage deprives the Company of revenues that have been allowed by the Commission as reasonable and prudently incurred. Ex. NGrid-2 at 18 (Stavropoulos).

Decoupling is "a vehicle for recovery of the revenue requirement approved in this case," NGrid Post-Hearing Mem. at 64, and nothing more. Decoupling will not insulate the Company from cost increases occurring in the normal course of business, some of which are highly sensitive to inflation, including labor, construction materials, and fuel costs. Therefore, the Company has the same incentive to reduce costs that it would have without decoupling. *Id*. at 65-66.

The Company disputes that the period of time that has passed since the last rate case demonstrates that the Company does not need an annual decoupling adjustment. The timing of this rate case is attributable to a rate freeze in effect through June 2005 and the transition of

ownership from Southern Union to National Grid. *Id*. at 69. The Company has not achieved its authorized ROE since fiscal year 2005, and declining gas usage per customer accelerated in 2004-2006. NGrid Post-Hearing Mem. at 70. The Company would not have made its authorized ROE from 2005 through 2008 even with decoupling. *Id*.

The Company also disputes that (1) weather normalization adjustments, higher fixed charges or declining block rates are alternatives to decoupling, (2) decoupling is unnecessary in light of state energy efficiency mandates, (3) decoupling will produce large annual rate increases for customers, and (4) decoupling will reduce customer incentives to conserve.

First, weather normalization, higher fixed charges, and declining block rates do not eliminate sensitivity of the Company to reduced revenues due to conservation (Tr. 10/23/08 at 180), which is demonstrated by the fact that all of these items were in place for the Company over the past five years and did not have the effect of maintaining revenues in the face of declining consumption. This is because higher fixed charges and declining block rates maintain a level of revenues despite declines in consumption but do not eliminate the impact caused by a reduction in use per customer. Tr. 10/22/08 at 99. Moreover, weather normalization does not protect against conservation, it simply operates to eliminate weather-related deviation from *average* from period to period. Over time, the cumulative weather normalization adjustments should approach zero as cumulative period to period weather approaches *average*. Ex. NGrid-13, at 31; Tr. 10/22/08 at 47. Also, a rate-design structure with higher fixed charges reduces the price signal to consumers to conserve. Tr. 9/26/08 at 172; Tr. 10/23/08 at 73. Thus, decoupling is the best means to generate the allowed level of revenues in the face of declining consumption, while maintaining appropriate price signals to customers.

Second, the record shows that decoupling will remove the disincentive for companies to reduce sales and has the potential to align the interests of utility with conservation. Tr. 9/29/08 at 164-165; Ex. TEC-RI-1, at 19. The record also shows that disincentives have a significant influence on utility policies and that utilities are key players in promoting conservation. Tr. 10/23/08 at 68, 73-74. The implementation of decoupling will encourage the Company to use its full expertise and resources to reduce customer usage. In contrast, although the utility will conduct a state-mandated program to the best of its ability, it has a disincentive to go beyond the confines of that program to promote conservation on a creative or aggressive basis. Tr. 10/22/08 at 28. Also, the incentive the Company receives for its gas DSM program is relatively small in terms of removing the Company's concern about revenues on a system-wide basis. *Id*. at 32.

Third, under traditional ratemaking, there are fewer, but larger rate increases, while decoupling increases occur on an annual basis to a lesser amount. Tr. 9/26/08 at 177. For instance, TEC-RI's expert witness agreed that the increase due to decoupling would be approximately $500,000 in 2007 and about $1,000,000 in 2008, and that these increases for 2007 and 2008 are relatively small. Tr. 9/29/08 at 92, 94-5. Cost increases of that size occur now with weather normalization. For example, weather normalization led to an increase of $927,000 in 2006 and $882,000 in 2007. Ex. TEC-RI-3 (Data Request TEC-RI 1-7). Thus, the concern regarding large annual increases is unfounded.

Fourth, decoupling will not reduce the incentive to conserve. Under the Company's decoupling proposal, customers will still be billed based on consumption, and the annual decoupling rate adjustment will be added or credited to the DAC. In addition, the decoupling rate adjustment is based on billed delivery charges only, where commodity revenues

account for 2/3 of the customer bill. Tr. 9/26/08 at 121-23. In the unlikely event that all residential heating customers installed conservation measures that reduced usage by 10 percent, which would theoretically produce a decoupling rate adjustment that would offset the delivery charge benefits of the conservation measures, the typical residential heating customer would still realize savings on the GCR portion of his bill, which is 70 percent of the bill. The average savings would be 4.7 percent or $71.43. Ex. NGrid-13, at 18-19. In addition, the decoupling rate adjustment will also be based on consumption which could also produce a price signal encouraging conservation. Thus, the record shows that in practical application the decoupling rate adjustment will not offset the delivery rate savings a customer would receive from conservation in addition to the GCR savings the customer will enjoy as a result of conservation.

Division Position. Decoupling has been approved in only a limited number of jurisdictions, mostly within the last two years. There is not much evidence of its impacts on ratepayers. This would be the first approval of decoupling for a gas utility in New England, and the first for National Grid in the U.S. Rhode Island would be an experimental starting point for the Company. Division Post-Hearing Mem. at 45, 48.

The Company already has at least four types of revenue decoupling included in its tariff: (1) a weather normalization adjustment; (2) declining block rates for residential heating and small commercial and industrial customers; (3) demand charges for medium, large and extra large commercial and industrial customers that are adjusted to reflect usage in the prior winter; and (4) the use of a future test year to reflect known reductions in consumption. Full revenue decoupling is not necessary or desirable. Divison Post-Hearing Mem. at 53; Ex. DIV-3 at 5; Tr. 10/24/08 at 9-10.

There is no evidence that full decoupling will produce energy conservation beyond what could be achieved under existing DSM programs. The Company has in the past systematically touted the success of DSM programs and its own commitment to executing cost-effective and innovative conservation programs. The Company is capable of maintaining its commitment to carry out what the Commission has already ordered and what state law mandates without a decoupling mechanism. Division Post-Hearing Mem. at 45-48, 53. A commitment to "reach for the stars" in the future is not a sufficient basis to order decoupling. *Id*. at 49, 53. Ratepayers will pursue energy efficiency regardless of whether decoupling is adopted. *Id*. at 53.

The Company's decoupling mechanism insulates the Company against revenue declines for any reason, not just conservation efforts. It essentially reduces the Company's revenue risk to zero. By divorcing Company performance from revenues, it shifts responsibility to the Commission to ensure that appropriate system and service quality are maintained. Revenue erosion from DSM is already reflected in rate year billing determinants, so the Company does not need decoupling to earn a fair return. Division Post-Hearing Mem. at 48-49; Tr. 10/8/08 at 24 (Czekanski).

Had revenue decoupling been in effect since the last rate case, the Company would have been insulated from revenue losses resulting from the "serious distraction" of the Southern Union and KeySpan mergers. There is evidence that the Company would have received an additional $34.1 million over the four year period with decoupling. Division Post-Hearing Mem. at 49-51; Tr. 9/26/08 at 100.

Approval of an annual reconciliation for accelerated pipeline replacement expenses mitigates any concern that traditional ratemaking procedures will not allow the Company to invest in infrastructure. *Id*. at 51.

Approving full decoupling raises complex issues regarding how to apply a weather normalization adjustment to rate classes exempted from the decoupling mechanism. If full decoupling is approved, the Commission's only option is to allow service to classes exempted from decoupling without any weather normalization adjustment. Division Post-Hearing Mem. at 54 n. 127.

Traditional regulation works. The Company has an appropriate incentive to exercise prudent cost management, and can periodically apply for a rate increase if necessary. This allows the Commission to review revenues and expenses together. Decoupling could potentially weaken Commission oversight of the Company by making rate cases more infrequent. *Id*. at 53. Decoupling will also discourage rate case settlements that could involve rate freezes or rate caps. Tr. 8/27/08 at 164.

Environment Northeast. ENE supports the proposed RDM, as modified. Full decoupling will help achieve the state's economic, energy efficiency, and environmental goals by better aligning the Company's financial incentives with customer and public policy interests in maximizing investment in efficiency efforts that are cheaper than supply. Under the current tariff, the Company derives a significant portion of its revenue through volumetric distribution rates. The Company therefore has an economic disincentive to support programs that would result in the reduction of gas consumption. The RDM would eliminate this disincentive for included rate classes. Because a portion of the distribution revenue would continue to be collected through volumetric rates, customers will still have an economic incentive to conserve on both the commodity and distribution parts of the bill. ENE Post-Hearing Mem. at 3-5. California has had a long, successful history with decoupling. Massachusetts has recently adopted it. *Id*. at 19-20

The Company is in a unique position to effect positive ratepayer decisions regarding efficiency investments, and can do so more forcefully with decoupling. State law already authorizes the Company to administer gas efficiency programs funded through a volumetric charge. R.I.G.L. § 39-2-1.2(d). State law recognizes that DSM programs may affect utility revenues and authorizes a rate adjustment clause to provide for full recovery of reasonable and prudent costs of a company implementing conservation procurement. R.I.G.L. § 39-1-27.7(d). The proposed RDM is consistent with this law because it would allow full recovery, and disallow over-recovery, of such costs. ENE Post-Hearing Mem. at 12-15.

State law authorizes utility efficiency programs, but does not mandate the level of investment or parameters of the programs. ENE Post-Hearing Reply at 5. Decoupling will encourage the Company to favor practices that promote efficiency and conservation, including advocating for tighter codes and standards, pushing technological improvements, and shaping the competitive marketplace for more efficient products. *Id*. at 3, n. 7. Rhode Island's per capita natural gas consumption (excluding usage for electric generation) is 37th in the country, and there are still a great deal of energy efficiency investments that are less costly than supply. *Id*. at 2-3, 5. While some customer conservation will occur without decoupling, there is strong evidence that utility DSM programs are important to remove cost barriers, perceived technology risks and information gaps that impede conservation. *Id*. at 5.

Existing so-called "partial" decoupling mechanisms such as weather normalization do not eliminate the Company's sensitivity to sales volumes. Decoupling does not guarantee Company profits. The Company will need to manage its costs carefully to earn its allowed return. The Company's motivation to reduce expenses and be efficient will be the same. *Id*. at 16-17; ENE Post-Hearing Reply at 6-7.

Excluding the four large rate classes from the RDM addresses ENE's concern that applying decoupling to small, heterogeneous rate classes could have unintended negative consequences. *Id*. at 18; ENE Post-Hearing Reply at 7-8. The RDM's design also eliminates any risk of cross-subsidization among classes. ENE Post-Hearing Mem. at 19; Tr. 9/12/08 at 10.

Conservation Law Foundation. CLF supports decoupling. Climate change is a crucially important issue to which the Commission should pay attention. Decoupling eliminates the disincentive to conservation and efficiency that exists in traditional ratemaking and aligns the utility's incentives with the public interest. CLF Post-Hearing Mem. at 3-6. State utility commissions in North Carolina, Ohio, Maryland, New York and Massachusetts have recognized the disincentive to promote energy conservation under traditional ratemaking and have ordered decoupling in recent dockets. CLF Proposed Findings of Fact at 10-12.

Traditional ratemaking does not work today as it has in the past because of declining gas use. As a result of declining use, the Company has been deprived of revenues allowed by the Commission. This has had an impact on safety because the funds are needed to operate the distribution infrastructure. The Company's proposed RDM true-ups ensure that the Company will receive its revenue requirement, neither more nor less. Moreover, the Company proposes maintaining the earnings sharing mechanism so that the Company and customers will share in earnings that exceed the allowed ROE. CLF Proposed Findings of Fact at 4-6.

Energy conservation and efficiency that would be fostered by decoupling will reduce overall gas consumption and benefit ratepayers by helping them avoid embedded carbon costs that will in the future be part of commodity prices. Reduced emissions of carbon dioxide will also ameliorate climate change. *Id*. at 8-9. CLF has opposed the Company in other dockets, but supports it here.

CLF disputes that the proposed RDM will erode incentives for customers to conserve energy. Approximately 70% of a ratepayer's bill is the commodity charge, which will decline in direct proportion to declining use. The remaining 30% is the distribution charge, which is also collected volumetrically. Even if the distribution rate increases because of the RDM adjustment, it would be offset by declining volume usage. *Id*. at 12-13.

TEC-RI Position. TEC-RI opposes decoupling. Decoupling is a major departure from traditional ratemaking, and can have a significant impact on ratepayers. NGrid Response to TEC-RI data request 1-7; NGrid Response to data request TEC 1-77 (15 states have approved decoupling). If decoupling had been in effect over the past four years, ratepayers would have paid an additional $34 million. Tr. 9/26/08 at 100; TEC-RI Post-Hearing Mem. at 13.

The Company has presented no evidence demonstrating that decoupling would produce more energy efficiency. It presented no new energy efficiency proposals to be implemented in Rhode Island, or efficiency studies from other jurisdictions with decoupling. Rhode Island already has the lowest energy use per capita, and ranks high in per capita utility energy efficiency spending. Decoupling is not needed, as indicated by the Company's request to withdraw its decoupling proposal from this rate case. TEC-RI Post-Hearing Mem. at 15; Tr. 9/8/08 at 5-7 (denying motion to withdraw).

Decoupling is not mandated by R.I.G.L. § 39-1-27.7(a)(2)(d). That statute (1) applies only to electric utility distribution, (2) permits, but does not require, adjustment, and (3) only allows rate adjustment for costs of system reliability, energy efficiency and conservation procurement, not for revenue changes regardless of the cause as allowed by the Company's proposed RDM. TEC-RI Post-Hearing Mem. at 16. The proposed RDM shifts risk from the Company to the ratepayer, but does not compensate ratepayers for assuming this risk. *Id*. at 17.

If decoupling is approved, large and extra large rate classes should be excluded. These classes have small numbers of customers and large variability in revenues among customers. Small changes in class membership could result in RDM adjustments that are not related to conservation efforts. Excluding these classes would not lead to cross-subsidization because RDM adjustments are calculated by class. No party opposes excluding large and extra large customers from the RDM. TEC-RI Post-Hearing Mem. at 10-11.

Office of Energy Resources. Rhode Island Office of Energy Resources opposes decoupling. OER states that "the record does not provide either a logical or a legal basis for adopting the proposed decoupling adjustment at this time." OER Post-Hearing Brief at 2; OER Post-Hearing Reply at 4 (there is "no empirical evidence to define the weight and nature of the claimed disincentive"). OER also states that the Company has already accounted for known and measurable future lost volumes in its rates, *id*. at 3, and that it has the management tools to offset any alleged disincentive to promote gas efficiency. *Id*. at 4. The record does not show why the Company cannot overcome any existing disincentive to promote conservation with existing management tools. OER further states that R.I.G.L. § 39-1-27.7(d) authorizes, but does not mandate, a decoupling adjustment. *Id*. at 5.

No customers support decoupling. Large and extra large C&I customers and low income customers have convinced the Company to exclude them. The remaining customers, represented by the Division, do not support decoupling. OER Post-Hearing Reply at 7.

Wiley Center. The Wiley Center opposes the Company's RDM, which shifts to ratepayers the risk of lost revenue from drops in usage regardless of the cause of those drops, and does not provide for a commensurate reduction in the Company's rate of return. If decoupling is approved, low income customers should be excluded. Low income customers cannot afford to

pay more for gas service. The RDM will result in an increase in the cost of gas service for the foreseeable future, as gas usage is decreasing. Wiley Post-Hearing Mem. at 9-10; Ex. Wiley 1 at 10 (Pre-Filed Direct).

Attorney General. The Attorney General adopts the Division's position on decoupling. Opening Remarks of the Attorney General at 1. Should the Commission adopt decoupling, however, the Commission should exclude low income residential heating and non-heating customers from the RDM. RIAG Post-Hearing Mem. at 1 n. 1.

Commission Decision. The record reflects that consumption of natural gas per customer has been declining since at least 1980. Ex. NGrid-12 at 28-29 and Attachment NG-JDS-4 (Simpson Direct). Some of the reduction in consumption is related to passive conservation measures, such as the forced replacement of old, failing gas appliances with new models that a re more energy efficient. Ex. NGrid-12 at 18 (Simpson). Other reductions are the result of active conservation measures, often in response to commodity price increases. *Id*. at 20-21. The impact on natural gas utilities of declining use per customer over the years has apparently been manageable with traditional ratemaking, under which gas utilities facing substantial usage declines are free to apply for a rate increase. It is clear that the Company's inability to earn its allowed return on equity in recent years is as attributable to the Company's own business activities as to declining use per customer. The last rate case involving the Company's Rhode Island natural gas operations was Docket No. 3401 in 2002. In the settlement of that rate case, the Company's predecessor agreed to a rate freeze until June 30, 2005. The Company cited its merger activity in 2006 and 2007 to explain its failure to request a base rate increase in those years. Tr. 9/12/08 at 90-95 (Simpson).

The Company states that the "primary reason for the Company's [decoupling] proposal is to advance the goal of achieving greater energy efficiency in the State of Rhode Island." Ex. NGrid-2 at 13 (Stavropoulos). Yet there is little or no evidence in the record to demonstrate how or why this would occur. The Company has not identified any new conservation or energy efficiency initiatives that it would undertake in the event that decoupling were approved. No party presented any study or analysis of additional energy efficiency that decoupling would produce in Rhode Island.

The Company's incentive or disincentive to embrace conservation initiatives in the absence of decoupling was the subject of conflicting testimony. A Company witness testified that incentives influence utility behavior, and that decoupling would cause the Company to reach for the stars in developing new conservation initiatives. Tr. 10/22/08 at 28 (Stavropoulos). Certain intervenors also testified that decoupling could be expected to induce the Company to more aggressively pursue conservation and energy efficiency. Tr. 10/23/08 at 68-69, 88 (Kaplan). On the other hand, the Division's expert witness testified that while decoupling might affect the Company's behavior, it would not necessarily have any impact. The Division's expert suggested several reasons why financial incentives might not affect the Company's behavior at all. Tr. 10/21/08 at 208 (Oliver).

The fact that decoupling may eliminate a disincentive for the Company to promote conservation, even if true, does not necessarily translate into any significant reduction in consumption above what would have been achieved as a result of local and national economic pressures, technology improvements, and other extrinsic factors. Regardless of decoupling, most customers will have an incentive to conserve because reduced usage translates directly into lower

commodity charges for the customer, and commodity costs currently account for over two thirds of the average residential bill.

Revenue decoupling would protect the Company from revenue declines attributable to any cause, not only energy conservation and efficiency efforts. Ex. DIV-5 at 37 (Rothschild) (decoupling would "significantly reduce the non-diversifiable risks exposure to NG investors by a revenue stream that would be essentially unaffected by swings in economic conditions in the service territory."). Decoupling would reduce the Company's revenue risk to zero, and shift the risk of revenue variations to ratepayers. Tr. 10/22/08 at 76 (Stavropoulos). While the record includes substantial evidence of the benefits of decoupling to the Company, the evidence that decoupling will benefit ratepayers is largely speculative. Indeed, the record reflects the significant financial impact on ratepayers that decoupling might have. Over the last four years, revenue decoupling would have resulted in an additional $34 million of payments to the Company. Ex. TEC-RI-3 (NGrid Response to TEC-RI Data Request 1-7); Tr. 9/26/08 at 100 (Simpson) ("If the revenue decoupling mechanism had been in effect for all rate classes the net effect would have been the $34 million that Mr. Farley calculates.").

The Company is already protected from revenue variations caused by unusually cold or warm weather, through the weather normalization adjustment. It is also allowed to adjust demand charges for medium, large and extra large commercial and industrial customers based on usage during the prior winter. The Company is also allowed to recover its commodity cost and, as a result of this docket, to reconcile its expenses for pension and PBOP costs and for the accelerated capital replacement program. These mechanisms already protect the Company against unanticipated revenue shortfalls in many areas, and mitigate the need for full decoupling.

Certain intervenors emphasize that other utility regulators have approved decoupling, and suggest that the Commission should follow their example. *See, e.g.*, CLF Post-Hearing Mem. at 10-11. The decisions of other regulatory bodies are not evidence that decoupling would materially contribute to energy conservation and efficiency in Rhode Island. Over time, the adoption of decoupling in other states may produce concrete evidence of ratepayer benefits that could reasonably be expected to occur in Rhode Island, but that has not yet occurred.

After careful consideration of the evidence and arguments presented by the parties and intervenors, the Commission finds that the Company has not carried its burden of proof on the proposed RDM. The parties agree that full revenue decoupling would be a significant change in traditional ratemaking policy in Rhode Island. To adopt full revenue decoupling, the Commission needs more than speculative assertions that it would promote additional conservation or energy efficiency. The record reflects that decoupling is still relatively new and untested in the United States, having only been approved by fifteen states, many of them within one to two years. Ex. TEC-RI-3 (NGrid Response to data request TEC 1-77); *see* Ex. CLF-3 (Mass. Department of Public Uitlities); Ex. CLF-5 (North Carolina Utilities Commission); Ex. CLF-7 (Maryland Public Service Commission); Ex. CLF-8 (New York Public Service Commission). The impact of full decoupling on utility behavior and on ratepayers is not clear.

Traditional ratemaking has worked well in the past. The Commission is responsible for reviewing utility operations, and a full base rate case where witnesses are subject to examination and cross-examination is a valuable opportunity to look at the entire operation of the Company. Revenue decoupling may have the undesirable consequence of further enlarging

the period between rate cases, thereby reducing public oversight. The Commission is not persuaded that experimenting with full revenue decoupling is appropriate at this time.[10]

E. Low Income Discount.

The Company proposed a 10% discount off of Commission-approved customer and distribution charges for low-income residential heating and non-heating customers eligible for LIHEAP assistance. Approximately 16,000 heating customers and 2,500 non-heating customers would be eligible. NGrid Post-Hearing Mem. at 92; Ex. NGrid-30 (tariff changes). The Company estimates that average savings for a low income residential heating customer would be approximately $54 per year. The estimated impact of the proposed 10% discount is approximately $800,000 to be recovered from other firm customers. The Company proposed that the cost of the discount be allocated based on consumption, although it had no objection to a different allocation method. Tr. 9/11/08 at 160 (Czekanski); NGrid Response to TEC-RI Record Request No. 1.

Company Position. The Company believes that a 10% low income discount reflects the proper balance between the interests of poor customers and other ratepayers. Tr. 9/11/08 at 159-160, 164-165 (Czekanski); Ex. DIV-13 (NGrid Response to Division Data Request 5-19). The 10% low income discount would supplement other existing assistance for low income customers. For the twelve months ending June 30, 2008, $9,108,481 was available to help reduce the bills of low income gas customers. NGrid Response to Record Request No. 21. In addition, $983,643 was available to support low income customers' energy efficiency efforts. *Id*.

[10] Commissioner Holbrook dissents from this portion of the decision and would allow full revenue decoupling for reasons stated on the record at the November 24, 2008 Open Meeting. Tr. 11/24/08 at 13-24.

Division Position. The Division takes no position on the proposed 10% discount on the grounds that the appropriate level for low-income rate assistance "is a highly subjective matter . . . and [the Division] is not in a position to render an opinion regarding the reasonableness or appropriateness of either the proposed rate discount levels . . . ." Ex. DIV-3 at 69 (Oliver).

TEC-RI Position. TEC-RI does not object to the 10% discount. However, TEC-RI opposes allocating the cost to other ratepayers based on class consumption. Under this method, rates for non-residential customers will be increased twice as much as rates for residential customers to pay for the low income discount. This method is different than the methods used by the Company in New York and Massachusetts. TEC-RI proposes that the cost of the discount be allocated to rate classes using a rate base allocator (class rate base as a percent of total rate base). TEC-RI Post-Hearing Mem. at 22, 25.

Wiley Center Position. The Wiley Center proposes a 1ow income discount of 50%. The economic crisis has deepened since the 10% discount was proposed. The annual out of pocket cost of utilities for the average low income household, taking LIHEAP and other assistance into account, is around $990 for gas and $823-$900 for electricity. This is about 13% of a minimum wage earning customer's wages, and 24% of the amount of assistance provided to a family of four on public welfare. Wiley Post-Hearing Mem. at 1, 5-6.

A low income discount is permissible under R.I.G.L. § 39-2-5(2) if it is "just and reasonable" or "in the interest of the public," and is not "unjustly discriminatory." The record shows that (1) the hardship borne by low income customers has worsened over the years, (2) low-income customers have been more severely affected by recent increases in commodity costs than other customers, (3) the discount may lessen the cost of terminating and restoring low

income customers, benefiting other ratepayers, and (4) other ratepayers may benefit as well from the stipulated $150,000 reduction in uncollectible expense. Wiley Post-Hearing Mem. at 2-4. The discount may also produce indirect ratepayer benefits from reduced health and public safety costs, and increased economic and educational productivity of low income customers. Ex. WC-1 at 9, WC-2 at 1 and App. 4. The impact on other residential and small and medium C&I customers ($2.21/year, $3.05/year and $26.28/year respectively on average, assuming the cost is spread volumetrically as proposed by the Company) is small. Ex. WC-3 at Data Request 1-8.

Utility regulators in Massachusetts, New Hampshire and Maine have added new protections for low income customers. In September 2008, the Massachusetts Department of Public Utilities ordered utilities to increase low income gas and electric discounts immediately, and the New Hampshire PUC increased the amount that other customers would pay to support tiered low income electric discounts. In August 2008, the Maine PUC increased funding for its electric low income assistance program by 13%. Wiley Post-Hearing Mem. at 7-9.

Attorney General's Position. The Attorney General "believes that the proposed discount is appropriate and reasonable in light of the value of the company's existing program and the substantial price increases that heating customers have experienced over the past year." Opening Remarks of the Rhode Island Attorney General, at 2.

The Commission possesses express statutory authority under R.I.G.L. § 39-2-5(2) to grant free utility service upon such conditions as the utility may impose, and may grant special rates to any special class or classes of persons so long as the rates are just and reasonable or in the public interest and are not unjustly discriminatory. The provisions of R.I.G.L. § 39-2-5(13) do not limit this authority. The expenses associated with the proposed low income discount are just and reasonable; the discount is not unjustly discriminatory; and the discount is in the public

interest. The Commission should allow all expenses associated with the discount as proposed. RIAG Post-Hearing Mem. at 20-27.

Commission Decision. The record evidence establishes that utility costs are a heavy economic burden for many Rhode Islanders, particularly those with very low incomes. The Commission finds that the proposed 10% discount offers a just and reasonable level of relief for the poorest Rhode Islanders, and is not unjustly discriminatory. For an average low income residential heating customer, the savings will be $49 per year. NGrid 11/26/08 Compliance Filing Attachment NG-Compliance RD-3, page 1 of 4. The Commission finds that the Wiley Center's proposed 50% discount is not supported by the record. All Rhode Islanders are facing unusually difficult economic times, and the approximately $800,000 cost of the 10% discount will be funded by other ratepayers, who in some cases may be only slightly better off than the discount recipients. The cost of the 10% low income discount to residential heating customer may be only a few dollars, but is only one of many increasing costs that cumulatively can be significant. Greater discounts face a heavier burden of proof of reasonableness, in light of their increasingly disproportionate benefit to the low income class and greater impact on other ratepayers to whom the cost of the discount is shifted.

The cost of the discount will be collected from other ratepayers based on consumption, as proposed by the Company. The Commission does not agree that TEC-RI's proposal to allocate the cost of the discount based on class revenue is appropriate.[11]

The Commission does not have the authority to require the Company to contribute shareholder funds to the proposed discount. The Company has made a voluntary contribution of $200,000 to the Good Neighbor Energy Fund, an amount that is equal to approximately 25% of

[11] Commissioner Holbrook dissents from the Commission's decision to approve the 10% low income discount and would refer this issue to the Rhode Island General Assembly, for the reasons stated on the record at the November 24, 2008 Open Meeting. Tr. 11/24/08 at 82-85.

the estimated cost of the discount that will be paid by ratepayers. The Commission urges the Company to consider increasing the amount of its voluntary contribution from shareholder funds to match the ratepayer funds that are being collected on account of the discount.

The Rhode Island General Assembly has in the past established a statewide energy affordability program, but the program was never funded and has now been repealed. The Commission would welcome the renewal and funding of that program. The Commission believes that a statewide energy affordability program approved and funded by the Rhode Island General Assembly would provide more accountability and, possibly, more resources for the energy costs of low income Rhode Islanders. The Commission's discretion to allow discounts is limited by the statutory requirement that any discount is just and reasonable and not unjustly discriminatory.

F. Non-Firm Tariff Issues.

1. Pricing for Non-Firm Transportation Customers.

Non-firm customers have dual-fuel capability, and agree that their gas service may be interrupted by the Company. Under the current "value of service" tariff, non-firm transportation service pricing changes monthly based upon the amount the customer would pay for its alternative fuel less a discount related to the customer's volume of consumption. The Company proposes maintaining the present "value-of-service pricing" for non-firm transportation customers, capped at 150% of the applicable firm service rate. The Division and certain intervenors propose "cost of service" pricing for interruptible service instead. The cost of non-firm service would be calculated based on a set discount off of the cost of firm service.

Company Position. The current tariff employs value of service pricing for non-firm customers. The tariff sets prices for non-firm customers such that the cost of the distribution charge and commodity charge combined is at a discount of between 2.25% and 22%

off the cost of the non-firm customer's alternative fuel (subject to a floor price of 10 cents/Dth in summer and 16 cents/Dth in winter). Value of service pricing acts as an incentive for non-firm customers to use gas distribution capacity that would otherwise be wasted, while simultaneously maximizing revenue for firm customers. The revenue impact of moving from value of service to cost of service pricing could be substantial for firm customers. Ex. NGrid-36; Tr. 10/8/08 at 6-17 (Czekanski).

As of September 1, 2008, there were 32 active non-firm service accounts. NGrid Response to Division Record Request No.-6. A preliminary engineering review conducted by the Company shows that 12 non-firm service customers can not be served as firm customers without system enhancements. *Id*. The estimated cost of the enhancements to bring a particular non-firm customer on line ranges from $9,000 to $3 million, depending on the customer. The estimated total investment needed to offer firm service to all existing non-firm customers is at least $9 to $10 million. *See* NGrid Response to Division Record Request No. 7.

The Company does not support a cost based rate for non-firm customers because a cost-based rate would normally include the cost of building and maintaining the system to meet the needs of all firm customers at peak periods. Allocating all of the system costs to firm customers implies that the cost of serving non-firm customers is equal to the marginal cost of service (primarily certain administrative costs). The Company disputes that marginal cost of service is an appropriate basis for setting non-firm rates, except to establish a floor for the least possible price that a non-firm customer should be paying. NGrid Post-Hearing Mem. at 84-85.

The Company also disputes that an embedded cost study is an appropriate basis for setting non-firm rates. An embedded cost study for non-firm customers requires judgments and assumptions about the assignment of costs that are inherently arbitrary. The embedded cost

studies produced by Company in this case demonstrate how different assumptions produce different results. NGrid Post-Hearing Mem. at 86-87; Ex. NGrid-38; Ex. NGrid-39.[12] Further, non-firm customers are not committed to the system and thus there is no assurance that costs allocated to the non-firm class will be recovered. NGrid Post-Hearing Mem. at 87.

Establishing a cost-based rate in the form of a discount off of firm service is not desirable because it will create an incentive to avoid taking firm service and does not allow for downward adjustment of the non-firm rate in the event that oil prices fall below natural gas. *Id*. The Company anticipates that a significant number of customers that migrated from non-firm to firm service in the past year would remigrate if a fixed, cost-based rate were established.[13] This would be poor ratemaking policy since it would have the effect of encouraging less use of the system. *Id*. at 88.

The Company argues that its proposed 150% cap is the best alternative for meeting the important ratemaking goals of (1) encouraging throughput regardless of the magnitude of price difference between gas and alternative fuels, (2) ensuring that firm customers receive an adequate benefit from non-firm use, (3) ensuring that non-firm pricing is fair and reasonable, and (4) ensuring that non-firm pricing does not undermine the integrity of the firm service rate or facilitate the avoidance of economical firm service. NGrid Post-Hearing Mem. at 90; Tr. 10/8/08 at 40-41, 112-115 (Czekanski); NGrid Response to Division Data Request 6-26.

Value of service pricing is not unjust or unreasonable because, with the exception of a few customers in capacity constrained areas of the system, it is the customer's choice to take non-firm service. Current non-firm pricing reflects the value to certain customers of being able

---

[12] The Company's response to data request DIV 5-53 (Ex. DIV-13) calculates non-firm COSS at $1.3 million, or $0.81/decatherm.

[13] Data request DIV 6-5 and 6-6 refer to transfers from non-firm to firm service.

to opt in and opt out at any time without making a firm commitment to the gas distribution system. NGrid Post-Hearing Reply at 21. A fixed discount is flawed because if there is no possibility that the system would lose non-firm throughput – as might be the case when the price of alternative fuels is high -- there is no reason for the Company to extend a discounted price to non-firm customers. *Id*. at 22.

Division Position. The Division proposes setting rates for non-firm transportation service at a fixed discount of 20% off of the customer's otherwise applicable firm rate (to be computed by dividing the sum of the projected variable distribution charge revenue and demand charge revenue for the customer's otherwise applicable rate class by the projected annual therms of gas use for the otherwise applicable firm rate class for the rate year). The Division also proposes establishing a revenue requirement of $2.856 million for the non-firm rate class, based on the Company's November 5, 2008 revised cost of service study, and revising the proposed joint stipulation regarding revenue reconciliation for non-firm service to provide that revenue above $2.856 million is split 75/25 between firm and non-firm customers. Division Post-Hearing Reply at 7-8.

TEC-RI Position. It is unjust and unreasonable to set non-firm distribution rates to maximize revenue because the Company is a monopoly. Non-firm pricing should be based on cost of service. Witnesses for both the Company and other parties testified that, because non-firm service can be interrupted on days when system capacity is constrained, non-firm customers impose very low demand costs. As stated by the Company,

> This result occurs largely because the actual 'cost' of providing non-firm service is minimal. Since the system is constructed and maintained to ensure uninterrupted service to firm customers on a year-round basis (i.e., through the peak winter periods), distribution capacity is available in the off-peak periods for use by non-firm customers at little or no additional cost.

Ex. NGrid-16 at 5 (Czekanski Rebuttal). The Company also testified that "[w]e design rates that are expected to cover the full cost of service. So essentially the firm customers have paid for all the firm capacity that we provide and make available." Tr. 10/22/08 at 19-20 (Stavropoulos). Rhode Island Hospital's expert testified that

> The direct costs and marginal costs are the only real costs that are caused by non-firm customers because the company, in its planning, does not add capacity to its distribution system in order to serve non-firm customers.

Tr. 10/22/08 at 206 (DeMetro).

TEC-RI argues that it is reasonable to infer that the Company's proposed floor for non-firm rates ($0.10/Dth summer, $0.16/Dth winter) is a good proxy for the marginal cost of non-firm service. The Company's November 5, 2008 embedded cost of service calculation results in a unit cost of $0.92/Dth, but uses the same demand cost allocation for non-firm customers as for firm customers. This is not a fair or reasonable reflection of demand cost causation because non-firm customers are interrupted on peak demand days. Ex. DIV-49 (number of non-firm curtailments from 2004-2008). Non-firm customers should be allocated 50% of the demand costs. This results in a non-firm class cost of service of approximately $1.8 million based on the Company's estimated usage volume. TEC-RI Post-Hearing Mem. at 4-8.

A non-firm class cost of service of $1.8 million is consistent with the revenue requirement that would be associated with the estimated $9-10 million investment necessary to serve all non-firm customers as firm customers. Record Request DIV-7; TEC-RI Post Hearing Mem. at 8-9.

Non-firm transportation rates should be set at a fixed 40% discount to firm rates. This produces $1.8 million of revenue on the 3.1 million Dth of volume the Company used in its November 5, 2008 cost of service study. TEC-RI Post-Hearing Mem. at 2, 9.

The Commission issued an order over a year ago asking for a cost of service based rate for non-firm service. The Company did not comply, and the Division also has not produced a cost of service based rate. The best record evidence supports the 40% discount off of firm rates proposed by TEC-RI and Rhode Island Hospital. TEC-RI Post-Hearing Reply at 2.

Rhode Island Hospital Position. The current non-firm tariff has produced dramatic and unpredictable changes in the Hospital's energy costs and unreasonably high prices over the past two years. RIH proposes that the Commission order a modified cost of service approach that would establish non-firm pricing at a discount off of firm pricing. The discount would set non-firm prices at a level that is more representative of the historic level of revenues collected from this class. RIH Post-Hearing Mem. at 1-2, 10-12.

Non-firm customers receive service only if there is excess capacity on the distribution system. The Company has not invested in the infrastructure that would be needed to serve non-firm customers as firm customers, an estimated expense of at least $9-10 million. The value of gas service is highest when demand is greatest. Rates charged to non-firm customers should be lower than those charged firm customers to reflect the less valuable service received. Instead, they are significantly higher; 400% higher in September 2008. RIH Post-Hearing Mem. at 5-7.

Under R.I.G.L. § 39-2-1, utility rates must be just and reasonable. Current non-firm rates do not meet this requirement because they bear no relationship to either firm rates or the cost of providing non-firm delivery service. The Company's proposed cap for non-firm rates at 150% of firm rates is arbitrary and unsupported by any reasonable rationale. The Company is using a cost based method to design rates for firm customers, but not non-firm customers. *Id*. at 7-9.

The non-firm cost of service studies presented by the Company are flawed because the Company allocated the demand-related costs of serving large firm C&I customers to non-firm customers. At most, non-firm customers should be allocated 50% of the distribution system demand costs calculated by the Company. Including allocated customer and commodity costs, non-firm customers should contribute $1.8 million to cost of service. This is representative of the historic level of revenues collected from the non-firm class. Based on Exhibits NGrid 36, 38 and 39, setting non-firm rates at a 35-40% discount off of firm rates would collect at least that target amount of revenue. RIH Post-Hearing Mem. at 10-12.

RIH's proposal would not skew rates for other classes. It is based on the Company's cost of service studies showing that revenues of $1.8 million from non-firm ratepayers would be a substantial contribution to distribution costs. This amount would be credited to firm rates, as is done currently. RIH disputes that non-firm customers are not committed to using natural gas. Non-firm customers have incurred and continue to incur substantial costs to maintain the capacity to burn gas, for both economic and environmental reasons. RIH Post-Hearing Reply at 3-4.

The current non-firm tariff is unreasonable and is creating undue and unnecessary hardships for a number of the state's largest employers at a time of economic uncertainty and high unemployment. Value of service pricing is producing rates significantly above the cost of serving non-firm customers and four times higher than the approved rates for firm customers. The extreme volatility of value of service pricing also makes it unfair and unreasonable. In 2008, value of service costs for RIH and other extra large high volume customers ranged from $0.10/Dth to $2.83/Dth. RIH Post-Hearing Reply at 3. The Company's proposed cap does not yield just and reasonable rates. RIH Post-Hearing Mem. at 13-14.

RIH strongly opposes the Company's revenue neutrality stipulation, which for purposes of the DAC increases the base level of non-firm contribution to $2.8 million. If the Commission does not accept the Company's proposal to cap non-firm rates at 150% of firm rates, this could result in a continuing surcharge to firm ratepayers. RIH proposes that the Commission instead direct the Company to remove the additional $1.2 million of former non-firm revenues assumed in developing firm billing determinants and provide it as a credit to DAC, with true-ups. RIH Post-Hearing Reply at 5-7.

Silent Sherpa Position. Silent Sherpa proposes setting the non-firm tariff based on a marginal cost of service analysis. The distribution system is bought and paid for and delivered to firm ratepayers. It would be redundant to charge the non-firm ratepayers for the same service. Tr. 9/29/08 at 229 (Grasso); Tr. 10/8/08 at 174-175.

Commission Decision. The Commission finds that the current value of service pricing system for interruptible transportation service is not functioning as intended. The record reflects that value of service pricing was established to create an incentive for dual fuel customers to use natural gas at times when the relative prices of gas and oil would otherwise have tended to encourage those customers to use oil. Even when priced below the cost of fixed service, interruptible service for dual fuel customers benefited ratepayers by generating net distribution revenues that would have been foregone in the absence of the value of service pricing. Thus, value of service pricing maximized revenues for firm service customers by attracting net revenue from customers that would otherwise have used an alternative fuel. Ex. DIV-3 at 51-52 (Oliver).

In an environment where oil and gas prices are comparable, or the cost of natural gas exceeds the cost of oil on a per therm basis, value of service pricing for interruptible service

also makes sense because it can be said to recognize the quality of the service being provided to dual fuel customers. Fixed service customers are entitled to use the Company's distribution capacity at all times, to draw the volume of natural gas the customer calls for. Interruptible service customers may have their access to the distribution system suspended on short notice. Furthermore, in parts of Rhode Island, the service suspension can last most of the winter. When value of service pricing results in the cost of interruptible service being below the cost of firm service, that differential can also be rationalized by looking at the actual and potential service interruptions faced by non-firm customers.

Under the current tariff, $1.6 million of non-firm customer revenue is assumed in base rates. Non-firm revenues above $1.6 million are shared 75/25 between ratepayers and the Company. In recent years, the cost of oil has risen relative to the cost of natural gas. Value of service pricing has produced sizable marginal revenues for firm customers, as follows:

2005 – $1,200,000

2006 – $1,400,000

2007 – $1,700,000

2008 – $2,700,000

Ex. NGrid-36.

Rising oil prices, and the resulting increase in non-firm revenues, indicate that changes to the current value of service pricing are necessary and appropriate. Even the Company appears to agree that some change is necessary, as it has proposed capping the non-firm transportation tariff at 150% of the firm transportation rate. While the Company's approach has the potential benefit of limiting non-firm rate increases, while still extracting substantial non-firm revenues for the benefit of firm ratepayers, the Commission is not persuaded that this

modification of value of service pricing is sound ratemaking policy. Given the changes in energy markets and the economy since value of service pricing was introduced, it is time to move to a new approach.

The Company's proposal to cap value of service pricing at 150% of the firm rate was not supported by any financial or economic analysis, or even by any testimony explaining why the Company's proposed percentage cap is superior to a cap set at a higher or lower percentage. Accordingly, there is no evidence to suggest that the Company's proposal will maximize revenues from non-firm customers, which the Company asserts is the goal of value of service pricing.

The Commission also is not persuaded by the Company's arguments that a cost of service-based alternative pricing mechanism is too complex, and requires too many assumptions about non-firm costs and usage, to be workable. It is reasonable to assume that the Company has the expertise and experience with non-firm customers in Rhode Island to make educated calculations decisions regarding likely expenses and revenues. The Company presumably made those kinds of calculations and decisions before agreeing to include $1.6 million of non-firm revenues in base rates under the current tariff. Furthermore, the record reflects that the Company's New York affiliate offers non-firm service priced at 100% of the firm tariff rate. Tr. 10/08/08 at 112 (Czekanski). There is no reason to think that the Company could not implement a similar approach here in Rhode Island.

TEC-RI and Rhode Island Hospital argue that the Commission should order non-firm rates be set at a 40% discount off of firm rates. They assert that this level of discount will generate non-firm revenues in line with "historical" levels, and sufficient to cover the estimated non-firm costs of service reflected in the Company's cost of service study marked as an exhibit

during the hearings. Setting non-firm rates at a discount off of firm rates would, in their view, be a fair recognition of the fact that firm customers are assured of service year round, while non-firm customers can have their service interrupted, often for substantial periods. TEC-RI and Rhode Island Hospital also see setting non-firm rates at a fixed discount off of firm service as a way of reducing the recent volatility of non-firm pricing, which they assert makes it difficult for large Rhode Island employers to budget for energy costs.

The Commission agrees that price stability is generally desirable, and that setting the price of non-firm service as a fixed percentage of the price of firm service is a fair and reasonable methodology. For several reasons, however, the Commission does not agree that a 40% discount off of firm rates is appropriate. First, the cost of service studies submitted by the Company during the hearings were criticized by the Division. Therefore, the Commission finds that these studies, without more, are not a sufficient basis to set a non-firm discount off of firm pricing. Second, evidence presented at the hearings indicated that substantial numbers of non-firm customers have migrated to firm service in recent months. Pricing non-firm service at too deep a discount off of firm service may encourage not only the migration of these customers back to non-firm service, but additional switching by firm customers who find a 40% discount off of the cost of firm service economically attractive. This could have the undesirable effect for firm ratepayers of discouraging use of the distribution system. Third, while the Commission agrees that in some ways the quality of non-firm service is inferior to the quality of firm service – because service interruptions are allowed – the record reflects that non-firm customers can and do switch back and forth between alternative fuels to take advantage of price and demand changes. This ability to switch back and forth, without being committed to the natural gas distribution system in the same way as a firm customer, has a value to the non-firm customer that

offsets the disadvantage of potential service interruptions. For all of these reasons, the Commission adopts the Division's recommendation that non-firm service should be priced at a 20% discount off of firm pricing.

On November 5, 2008, the Company and the Division entered into a stipulation to address the potential revenue effects of the Commission's decision on this issue. NGrid Post-Hearing Mem. at 90; Division Post-Hearing Mem. at 37. The stipulation created a mechanism to account for the various possible migrations of customers between firm and non-firm service, depending on how rates for non-firm service are ultimately established, in order to assure revenue neutrality for customers and the Company. Going forward, non-firm distribution revenues will be determined by combining revenues (exclusive of gross earning tax) from the customers identified in the stipulation plus margins received from non-firm special contracts and new non-firm customers taking non-firm service after that date. For the period ending June 30, 2009, the Company will calculate the total non-firm transportation margins for the eight month period ending June 30. If the total non-firm margins are greater than $1,879,800 during that period, firm rate payers will receive credit for the excess through the DAC. If the total is less than $1,879,800, firm ratepayers will make up the difference through the DAC. For years ending June 30, 2010 and after, the break point for DAC credit will be $2,816,000. NGrid Post-Hearing Mem. at 90-92. The Commission approves the stipulation.

2. <u>Sharing of Non-Firm Revenues.</u>

Under the existing tariff, seventy-five percent of non-firm revenues above $1.6 million are credited to the ratepayers; the other 25% are retained by the Company. In the year ending June 30, 2008, firm customers received $2,884,688 over and above the $1.6 million built into the revenue requirement, for a total firm customer benefit of $4,484,688. Ex. PUC-7 (NGrid Response to Data Request COMM 3-9). The Company's 25% share for the same period

amounted to $961,563. Since 2003, the Company has retained a total of $2,628,300 of non-firm margin. *Id*.

Company Position. The Company proposed retaining the revenue split.

Division Position. The Division objected to retaining the revenue split. Ex. DIV-3 at 64 (Oliver). The Division argued that while value of service pricing was originally designed to encourage maximization of revenues from non-firm customers with access to competitively priced alternative fuels, that basis no longer exists after industry restructuring. Ex. DIV-3 at 51, 62-63 (Oliver). The Division argued that the Company's retention of this margin does not affect its pricing of non-firm service, or the behavior of non-firm customers. Division Post-Hearing Mem. at 38-39. The Division further argued that it is not reasonable for the Company to continue sharing the benefit of non-firm margins above $1.6 million, while ratepayers absorb all of the risk of returns below that level. *Id*. at 39.

Commission Decision. The Commission finds that in light of its decision to fix non-firm prices at a 20% discount off of firm prices, there is no longer any reason to offer the Company a share of non-firm revenues as an incentive to maximize those revenues. The Company's proposed revenue split is denied.

3. Lock In Period.

The Company proposed enlarging the time for non-firm transportation customers to lock in service prior to the beginning of a month from five to ten days. The Commission approves this proposed change.

4. Flexible Firm Service.

The Company proposed Flexible Firm Service, a firm transportation service based on negotiated, individual service agreements with dual-fuel C&I customers with usage above 150,000 therms. Ex. NGrid-15 at 21 (Czekanski). The Division opposed the proposal, citing a

lack of detail and the possible inequality of bargaining strength between the Company and a non-firm customer. Division Post-Hearing Mem. at 40; Ex. DIV-3 at 62 (Oliver). The Commission agrees that the proposed Flexible Firm Service lacks sufficient detail, and therefore declines to approve it at this time.

5. Non-Firm Sales Service Tariff.

The Company proposed eliminating non-firm sales service. Ex. NGrid-15 at 22 (Czekanski). TEC-RI proposed that the Company retain the non-firm sales tariff until the Company determines that no current customer under that tariff will be harmed if it is eliminated. TEC-RI Post-Hearing Mem. at 2. The Commission has not been presented with sufficient evidence to determine the full implications of eliminating non-firm sales service, as proposed. The Company's request to eliminate non-firm sales service is therefore denied.

G. Firm Service Rates

The Company proposed raising customer charges for residential customers from $9 to $16, and proposed increases for commercial and industrial customers (excluding Extra Large C&I) as well. The overall increase in distribution revenue requested by the Company is 15.95%. Proposed increases for certain classes range from 46.7% to over 114%. Division Post-Hearing Mem. at 43; Ex. DIV-3 at 45 (Oliver).

The Division objected to the proposed increases in customer charges, arguing that violate the ratemaking principles of gradualism, continuity and avoidance of rate shock. The Division proposes that no class should receive increases in customer and demand charges exceeding the greater of 33% or the class average increase. Tr. 8/27/08 at 182; Division Post-Hearing Mem. at 43.

The Commission finds that the proposed increases in customer and demand charges are excessive in comparison to the proposed increase in the Company's distribution

revenue requirement. The Commission approves the Division's recommendation that no class should receive increases in customer and demand charges exceeding the greater of 33% or the class average increase.[14]

H. Other Rate Design Issues

1. Consolidation of Gas Cost Rate Charges.

The Company proposed to reduce the number of Gas Cost Recovery rates from six to two. The Company asserts that this change will simplify the GCR calculations and associated monthly reporting of deferred gas cost account balances. NGrid Post-Hearing Brief at 58. The Division supports the Company's proposal, concluding that it would have no significant adverse impacts. Ex. DIV-3 at 73 (Oliver). TEC-RI opposes this change as a step away from cost of service pricing. TEC-RI believes that it could increase the GCR rates for certain classes by $0.10 /Dth or more, which translates into approximately $2.3 million. TEC-RI Post-Hearing Mem at 23-24.

The Commission finds that reducing the number of gas cost recovery rates will simplify the calculations and reporting and is in the best interest of ratepayers. The Commission approves the Company's proposed consolidation of six gas cost recovery rates to two rates.

2. DAC Adjustments

The Company proposed several changes to the Distribution Adjustment Clause to reflect other tariff changes requested by the Company in its filing. The Commission approves DAC cost recovery mechanisms consistent with its rulings set forth above for the Company's Accelerated Replacement Program and pension and PBOP expenses. The Commission also approves elimination of the Consolidation Mitigation and ERI adjustment. The other DAC

[14] Commissioner Bray dissents from this portion of the Commission's decision and opposes any increase in the fixed customer charge for reasons stated on the record at the November 24, 2008 Open Meeting. Tr. 11/24/08 at 99-101.

adjustments proposed by the Company are denied as moot in light of the Commission's rulings on decoupling and recovery of gas cost related bad debt. TEC-RI's request to modify the DAC mechanism to allocate DAC costs and credits to rate classes based on class revenues (as a proxy for cost of service allocation) instead of through a volumetric charge is denied.

3. <u>Three Year Rate Plan Proposal.</u>

The Company proposed an alternative three year rate plan. The plan would phase in rate increases approved in this proceeding. The Division opposed the Company's alternative three year plan, arguing that (1) it is less beneficial if the Company's revenue proposal is reduced as recommended by the Division, (2) it is difficult to forecast revenue requirements for the two years after the rate year with any degree of certainty, (3) incorporating Commission modifications to the Company's proposed revenue requirement over three years is complex, and (4) the proposed three year plan would generate approximately $23 million of revenues in excess of the revenues produced by the alternative request for a one time increase of $20 million. Division Post-Hearing Mem. at 34-35.

The Commission finds that the approved distribution revenue increase of approximately $13 million is less burdensome to ratepayers than the Company's initial $20 million request. The Commission further finds that the additional cost and complexity of phasing in the increased revenue requirement over three years outweighs the benefits of a phase in for ratepayers. The Commission declines to approve the Company's alternative three year rate plan.

Accordingly, it is

(19563) ORDERED:

Decoupling

1. Revenue Decoupling Mechanism. The Company's proposed revenue decoupling mechanism for the residential non-heating, residential heating, small C&I and medium C&I rate classes, under which the surplus above or shortfall below target revenue per customer would be credited or collected through an annual adjustment of the DAC, is denied;

Revenue Requirement Issues

2. Revenue Requirement. A rate year revenue requirement of $139,266,486 is approved, representing a $13,659,773 (10.88%) increase over the test year of $125,606,713.[15]

3. Capital Structure. The Company's proposed capital structure for ratemaking purposes of 47.71% equity, 40.63% long-term debt and 11.66% short-term debt is approved;

4. Return on Equity. The Company's proposed return on equity of 11.50% is denied. The Company shall be allowed a return on equity of 10.50% for its Rhode Island operations;

5. Size of Rate Base. The Company's proposed rate base of $285,241,458 is approved, provided that, in the event that the projected capital spending does not occur prior to the end of the rate year, the Company shall notify the Division and

[15] In response to the Commission's open meeting ruling on November 24, 2008, the Company submitted a Compliance Tariff Filing consistent with the approved revenue requirement. The Commission approved the filing on December 1, 2008. Order No. 19528 (issued January 8, 2009). A copy of Compliance Tariff Filing, Schedule NG-Compliance MDL-1, page 1 of 2 and Schedule NG-Compliance RD-1 is attached hereto as Appendix A.

make an appropriate adjustment to reflect the actual lower amount of actual plant in service;

Operating Expenses (Cost of Service)

6. Health Care Costs. The Company's proposed rate year medical and dental costs of $4,614,616 shall be reduced by $907,456, to $3,707,150;

7. FAS 112 Expense. The Company's proposed FAS 112 expense – relating to post-employment benefits other than pension – of $740,000 for FY 2009 is approved;

8. Synergy Savings – Southern Union Merger. The Company's proposed $1,054,609 synergy saving from the Company's August 2006 acquisition of the Rhode Island operations of New England Gas Company from Southern Union is denied;

9. Synergy Savings – KeySpan Merger. The stipulation between the Company and the Division relating to synergy savings resulting from the Company's August 2007 merger with KeySpan Corporation is approved. A base rate revenue credit of $2.45 million shall be included to reflect the ratepayers' 50% share of projected merger synergies net of costs to achieve. The Company shall be allowed to include its $2.45 million share of projected merger synergies in future rate cases, and to reflect its share of savings in annual earnings reports filed with the Commission for earnings sharing purposes, to the extent permitted by the stipulation. The Company's request for permission to create a regulatory asset in accordance with FAS 71 is approved;

10. Gas Marketing Program. The Company's proposal to include $1,377,000 in the base revenue requirement for a Gas Marketing Program is denied;

11. Uncollectible Expenses. The stipulation between the Company and the Division to reduce the Company's proposed uncollectible accounts receivable expense of $3,594,522 by $150,000 is approved;

12. Rate Case Expense. The Company's total rate case expenses of $1,348,443 (including Company expenses of $884,481, Division expenses of $113,075, and Commission expenses of $350,887) are approved. The Company shall be allowed to recover these expenses amortized over a three year period, or $449,481 per year;

13. Encroachment Expenses. The Company's proposed $1,054,000 for operation and maintenance expenses relating to public works and third party encroachment is denied. Encroachment expenses of $298,000 are approved;

14. Distribution Maintenance. The Company's proposed distribution maintenance expenses shall be reduced by $539,000, to $16,265,000;

Revenue Reconciliation Proposals

15. Accelerated Capital Replacement Program. The Company's proposed Accelerated Replacement Program to increase the annual replacement of distribution mains and remove high pressure inside services is approved, subject to the modifications recommended by the Division. Beginning in January 2009, the Company will submit a proposed implementation schedule to the Division each January for comment, and secure Commission approval. The Company will also submit a reconciliation report for each fiscal year. The first ARP reconciliation report for the 12 months ending March 31, 2009 will be submitted by May 15, 2009 for a rate adjustment effective July 1, 2009. The ARP will

entitle the Company to a rate adjustment only to the extent of the capital cost that is incremental to the amount included in base rates in this proceeding.

16. Gas-Supply Related Bad Debt Cost. The Company's proposed bad debt ratio of 2.46% for base rates is approved. The Company's proposed gas cost related bad debt reconciling mechanism is denied;

17. Reconciliation of Pension and PBOP. The Company's proposed annual reconciliation mechanism for pension and PBOP (post-retirement benefits other than pension) expenses is approved;

Low Income Discount

18. 10% Low Income Discount. The Company's proposed 10% discount of off Commission-approved customer and distribution charges for low income residential heating and non-heating customers eligible for LIHEAP assistance is approved. The discount shall be collected from other ratepayers based on consumption, as proposed by the Company;

Non-Firm Tariff Issues

19. Pricing for Non-Firm Transportation Customers. The Company's proposed cap on non-firm transportation rates at 150% of firm rates is denied. Non-firm transportation rates shall be set by the Company at a 20% discount off of firm customer rates. The Company's proposed sharing of non-firm revenues above $1.6 million is denied. The November 5, 2008 stipulation between the Company and the Division creating a mechanism to account for the various possible migrations of customers between firm and non-firm service is approved;

20. Lock In Period. The Company's proposal to enlarge the time for non-firm transportation customers to lock in service prior to the beginning of a month from five (5) to ten (10) days is approved;

21. Flexible Firm Service. The Company's proposal to establish a flexible firm transportation service is denied;

22. Non-Firm Sales Service. The Company's proposal to eliminate non-firm sales service is denied;

Firm Service Rates

23. Firm Service Base Charge. The Company's proposed increases in customer and demand charges shall be modified such that no class of ratepayers shall receive increases in customer and demand charges exceeding the greater of 33% or the class average increase;

Other Rate Design Issues

24. Consolidation of Gas Cost Recovery Rates. The Company's proposed consolidation of gas cost recovery rates from six rates to two rates is approved;

25. DAC Adjustments. The Company's proposed DAC cost recovery mechanisms for the Company's Accelerated Capital Replacement Program and pension and PBOP expense reconciliation are approved. The proposed elimination of the Consolidation Mitigation and ERI adjustment is approved. Other DAC adjustments proposed by the Company and TEC-RI are denied;

26. Three Year Rate Plan. The Company's proposed alternative three year rate plan is denied;

27. The Company is further ordered to comply with the reporting requirements and all other findings and directives contained in this Decision and Order.

EFFECTIVE AT WARWICK, RHODE ISLAND, PURSUANT TO AN OPEN MEETING DECISION OF THE COMMISSION ON NOVEMBER 24, 2008. WRITTEN ORDER ISSUED JANUARY 29, 2009.

PUBLIC UTILITIES COMMISSION

Elia Germani, Chairman

Robert Holbrook, Commissioner

Mary E. Bray, Commissioner

APPENDIX A

National Grid - RI Gas
Approved Revenue Requirement
Commission Open Meeting - November 24, 2008

			Decision Matrix Item
1	Co Rebuttal Position	$18,455,310	
2	Health care Adjust	(907,456)	5
3	FAS 112	740,000	6
4	SU Synergy Savings	(896,971)	7
5	SU CTA Amortization	(157,637)	7
6	Gas Marketing	(1,377,000)	9
7	Rate Case Expense (see page 2 of 2)	183,731	11
8	Low Income Uncollectible Adj	(150,000)	10
9	Pre-tax Return @ 10.50% ROE (5.01% - 5.49% * 286,031,702) /.65	(2,112,234)	2, 3 & 4
10	Rev Req Adjustment subtotal (sum of Lines 1 through 9)	(4,677,567)	
11	Bad Debt impact ((Line 10 / .9754) - Line 11)	(117,970)	
12	Total Revenue Requirement (Line 1 plus lines 10 & 11)	$13,659,773	

NationalGrid RI
Docket No.3943
Proposed Revenue Spread - Compliance

Line No.	Rate Schedule	Current Distribution Revenue	Proposed Increase	Proposed Distr. Rev. before LI Discount	Percentage Increase	Low Income Full Rate Reallocation	Low Income Discount Revenue $ 792,453	Total Proposed Distribution Revenue
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
1	Residential Non-Heat	$ 5,133,293	$ 781,903	$ 5,915,196	15.23%	$ (485,600)	$ 12,037	$ 5,441,633
2	Residential Non-Heat Discount	-	-	-	0.00%	485,600	(48,565)	437,035
3	Residential Heat	82,164,785	8,939,534	91,104,319	10.88%	(7,439,952)	379,512	84,043,878
4	Residential Heat Discount	-	-	-	0.00%	7,439,952	(743,888)	6,696,064
5	Small C/I	10,491,164	1,426,798	11,917,962	13.60%		54,238	11,972,200
6	Medium C/I	14,650,241	1,155,611	15,805,852	7.89%		120,912	15,926,764
7	Large Low	6,730,933	530,936	7,261,869	7.89%		60,898	7,322,767
8	Large High	1,812,681	172,370	1,985,051	9.51%		23,720	2,008,771
9	X-Large Low	1,108,782	156,826	1,265,608	14.14%		27,671	1,293,279
10	X-Large High	3,473,673	491,316	3,964,989	14.14%		113,465	4,078,454
11	NGV	22,738	2,474	25,212	10.88%			25,212
12	Gas Lights	18,423	2,004	20,427	10.88%			20,427
13	Total	$ 125,606,713	$ 13,659,773	$ 139,266,486	10.88%	$ -	$ 0	$ 139,266,486
14	Percent Increase		10.88%					