Thomas R. Teehan
Senior Counsel

November 6, 2008

VIA HAND DELIVERY & ELECTRONIC MAIL

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

RE: Docket 3943 – National Grid Request for Change of Gas Distribution Rates
National Grid Post Hearing Brief

Dear Ms. Massaro:

Enclosed please find eight (8) copies of the post hearing brief of National Grid[1] in the above-referenced docket.

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

Very truly yours,

Thomas R. Teehan

Enclosures

cc: Docket 3943 Service List

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

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I. INTRODUCTION

On April 1, 2008, National Grid put forth a request for base-rate relief, along with certain other ratemaking proposals. If and when approved, the Company's request for an increase in base revenues will represent the first time in almost ten years that base rates would be raised. The filing was made necessary at this time to address a significant revenue deficiency arising from a systemic deterioration of the Company's ability to recover its cost of service in Rhode Island through existing rates. This deterioration resulted from a number of factors including unprecedented customer conservation, which eliminated revenue that was expected to occur when rates were originally set, persistent inflationary pressure on operating and maintenance expenses, and the cost of making up for historic under-investment (by previous owners) in system replacements and upgrades to ensure the safety and reliability of gas service. In short, the Company found it necessary to make a filing in order to reverse the trend of declining revenues and to establish a structure that would support a strong commitment to safety, reliability, customer satisfaction and environmental health, while also ensuring the availability of affordable gas service to Rhode Island customers.

Since acquiring the Rhode Island gas distribution operations in 2006, the Company has embarked on a concerted effort to improve the safety and reliability of the distribution system, to achieve administrative and operational efficiencies in order to reduce costs, and to establish a culture focused on growth, investment and corporate and environmental integrity. Since its acquisition of the Rhode Island gas operations on August 24, 2006, the Company has expended the funds necessary to make fundamental changes in this regard. However, in the two years that the Company has owned the gas operations, its earned return on equity has been below 1% for the 12-months ended June 30, 2007 and 2008. For the Company, the situation is not sustainable. Therefore, the Company is asking the Commission to approve a revenue requirement

incorporating a fair and reasonable rate of return and capital structure, and also to approve certain ratemaking mechanisms that will provide the Company with a more reasonable opportunity to earn a fair rate of return over time.

The Company's objectives in establishing the framework for fair and reasonable cost recovery are founded on a long-term perspective regarding the elements that are necessary to protect and serve the public interest. The state of the economy is poor and customers are suffering the results, which makes it incumbent upon the Company to deploy its financial and staffing resources to three critical goals: (1) to contain distribution costs that are within the control of the Company to the maximum extent possible through efficiency gains and cost-reduction measures, (2) to spread the costs that are incurred to provide safe and reliable service across as broad a customer base as possible, and (3) to find ways to deliver affordable and cost-effective conservation opportunities so that customers can reduce their end-use consumption and energy costs. The interests of Rhode Island customers will be served by a ratemaking model that provides the Company with the tools and motivation to achieve these goals, while also encouraging the level of investment necessary to ensure safety and reliability. The Company's rate proposals are geared to this end.

In this document, The Narragansett Electric Company d/b/a National Grid ("National Grid" or the "Company") sets forth its post-hearing brief and proposed statement of findings in relation to its April 1, 2008 request for base-rate relief. For each issue, the Company has summarized its proposal (incorporating any corrections or changes made during the proceeding) and addressed concerns raised by the intervenors with a detailed review of the record evidence supporting the Company's proposals in order to demonstrate that approval by the Commission is warranted and appropriate. For each issue requiring a determination by the Commission, the

Company has included a proposed statement of findings by the Commission. In terms of organization, the Company has organized its brief as follows:

- Section I is the introduction.
- Section II discusses the proposed revenue requirement, with a focus on the issues that constitute the difference between the Division's position and the Company's rebuttal position, including return on equity and capital structure.
- Section III discusses the ratemaking changes that will be implemented through the Distribution Adjustment Charge ("DAC") and Gas Cost Recovery ("GCR") factors, including pension and PBOP expense reconciliation, commodity-related uncollectible expense reconciliation, the Accelerated Replacement Program ("ARP") and other miscellaneous tariff changes required to implement the Commission's ratemaking decisions in this docket.
- Section IV discusses the Company's decoupling proposal.[1].
- Section V discusses the Company's non-firm pricing proposal.
- Section VI discusses certain rate design issues and the proposed low-income discount.

[1] Although discussed in a separate section, the Company's ratemaking change related to decoupling, which is discussed in Section V, will also be implemented through the DAC.

II. BASE REVENUE: REVENUE REQUIREMENT

A. Overview

As filed, the Company calculated a revenue deficiency of $20,036,103 million.[2] On rebuttal, the Company's calculation of the deficiency was reduced to $18,455,310 million.[3] This amount was further reduced by the Company to $18,137,854 as a result of three additional adjustments agreed to by the Company subsequent to its rebuttal testimony (health care cost, FAS 112 and uncollectible expense).[4] The Division's surrebuttal testimony calculated a revenue deficiency of $8,745,000.[5] When adjusted for the agreement reached on the treatment of uncollectible expense relating to the low-income discount, the Division's adjusted revenue deficiency amounts to approximately $9,010,000 (by the Company's calculation). Thus, the Company's calculation of the difference between the Company's (adjusted) rebuttal position and the Division's (adjusted) surrebuttal position is approximately $9.1 million, which is accounted for as follows:

Operating Expenses	=	$3.6 million
ROE and Capital Structure	=	$5.5 million (incl. taxes)
Total Difference	=	$9.1 million

The difference in the allowable cost associated with ROE and the capital structure arises from a difference between the Company and the Division in relation to: (1) allowable rate base

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[2] Exh. NGRID-3, Vol. 1, at 41.

[3] Exh. NGRID-4, at 27; Exh. COMM-3 (Att. COMM-2-3, at page 1).

[4] Specifically, the Company agreed to reduce its health care expense adjustment by $907,456 as proposed by the Division. Second, the Company included a FAS 112 adjustment of $740,000, down from the originally estimated cost of $912,846, which eliminated the "catch-up" portion of the expense (see, Tr. 9/8/08, at 96). In its rebuttal case, the Company had proposed that due to the offsetting nature of the health care and FAS112 expense adjustment amounts, no change to the cost of service was needed. Finally, the Company agreed to deduct $150,000 from its revenue requirement to address the Division's claims of benefits associated with the Company's proposed low income discount. This second adjustment also reduces the Division's calculated expense from $415,000 to $150,000 (Tr. 9/11/08, at 146).

[5] Exh. DIV-2, at Schedule DJE-1S.

through the end of the rate year, (2) the appropriate cost of common equity, and (3) the percentage of common equity to be included in the capital structure for ratemaking purposes.[6]

With respect to these issues, the record is clear that the outcome of the Commission's determinations on the rate of return for common equity will be stated in the Commission's order and will send a "very powerful signal" to management and to the investment community "as to whether Rhode Island is the place to invest."[7] National Grid is strongly committed to infrastructure investment, system maintenance and operating efficiency, which requires continual investment in manpower, technical expertise, information systems and infrastructure materials. However, to support these commitments, the Company must seek capital in financial markets that are experiencing truly unprecedented turmoil. Although the Division's witness tried to downplay this dynamic with testimony that financing has, in the past, occurred at the UK level irrespective of regulatory decisions in the various U.S. state jurisdictions, the Company and its financial analysts are sensitive to the fact that the regulatory decisions made by the Commission in Rhode Island will have a direct impact on the Company's financial standing in capital markets.[8]

In terms of operating expense, there are three items that comprise the bulk of the difference between the Company's calculation and that of the Division, which are: FAS 112 expense, the quantification of NGRID/SU merger synergies and Gas Marketing Program expenses.[9] Specifically, the breakdown of the differential in operating expenses is as follows:

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6 See, Exhs. NGRID-8 and 9 and Exhs. DIV-5 and 6.

7 Tr. 9/10/08, at 75.

8 See, Exh. DIV-11 (Data Request DIV-3-22).

9 See, Exh. COMM-3 (Att. COMM-2-3, at pages 4-6).

FAS 112 Expense	$ 740,000[10]
Company Share of NGRID/SU Synergy Savings	$1,054,609[11]
Gas Marketing Program Expenses	$1,229,000[12]
Bad Debt Expense Adjustments	$ 228,635[13]
Depreciation Expense	$ 347,000[14]
Total Operating Expenses Subject to Dispute	$ 3,599,243

Accordingly, the sections below first cover the issues relating to capital structure, ROE and rate base and then cover issues relating to operating expenses. Among other issues relating to operating expense items, the Company is requesting that the Commission provide the Company with the opportunity to present the Commission with a final rate-case expense tally so that costs incurred by the Commission and the Division that are chargeable to the Company can be included in final rates.

CAPITAL STRUCTURE, ROE AND RATE BASE

B. Capital Structure

- *Summary of Company Proposal*

The Company's Rhode Island gas distribution operations are owned by The Narragansett Electric Company, which has an actual capital structure composed of a large proportion of

[10] Tr. 9/8/08, at 96.

[11] The Company is requesting to recover 50 percent of the net synergy savings achieved through National Grid's acquisition of the Rhode Island operations of New England Gas Company through rates, consistent with past practice (Exh. NGRID-3, Vol. 1, at 61-66). Per the Company's rebuttal testimony, the amount to be included in rates (including $157,638 of annual amortization of costs to achieve the savings) is $1,054,609 (Exh. NGRID-4, at 13).

[12] The Company is requesting to recover $1,377,000 million in operating expenses for the Gas Marketing Program (Exh. NGRID-6, at Vol. 2, at 25, 27). The Division's position is that no more than $148,000 should be included in rates (Exh. DIV-3, at 26). The net amount subject to dispute is $1,229,000 (Exh. COMM-3, Att. COMM-2-3, at page 4).

[13] The Commission does not need to render a determination on these expense items because the final amount results from the Commission's determination of other issues, including allowable rate base, ROE and capital structure.

[14] The difference in depreciation expense is entirely related to differences in rate year plant in service. The Commission's final determination on rate year plant in service will determine rate year level of depreciation expense.

common equity rendering the actual capital structure inappropriate for use in the ratemaking process.[15] Therefore, in accordance with the Commission's precedent, the Company proposed a capital structure derived from the capital structures of regulated gas companies forming the same proxy group used for the ROE calculation.[16] The Company's actual short-term debt ratio was factored into the proxy group average capital structure.[17] The proposed capital structure is comprised of 40.63% long-term debt, 11.66% short-term debt and 47.71% common equity.[18] The five-year average common equity ratio for the proxy group was 52.4% based on permanent capital.[19]

- *Discussion of Record Evidence*

The Division proposed that the Commission use the capital structure of National Grid plc, which is the United Kingdom ("UK") parent of Narragansett's parent company, National Grid USA.[20] The capital structure calculated by Mr. Rothschild as being the capital structure of National Grid plc is composed of 59.06% long-term debt, 3.17% short-term debt and 37.77% common equity.[21] The record shows that there are several flaws with the Division's recommendation:

First, the record shows that the use of the actual capital structure for National Grid plc is inappropriate because it is the capital structure of a non-domestic, unregulated holding company that owns and operates a global operation encompassing a wide range of unregulated activities

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15 Exh. NGRID-9, at 10-11.

16 Id. at 12.

17 Exh. NGRID-8, at 4

18 Id.

19 Id., at 16.

20 Exh. DIV-5, at 7.

21 Id., at JAR Schedule 1.

with different business risks.[22] Significantly, the Division's witness testified that he made his recommendation without any specific knowledge of the nature of National Grid's unregulated activities or to determine the reasonable range of capital structures in the UK, yet he has assumed the impact of these operations in his proposed capital structure.[23]

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.[24] 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%.[25] 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.[26] The average common equity ratio was demonstrated to be 52.06%.[27] 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.[28] 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

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22 Exh. NGRID-9, at 9-16; Tr. 9/10/08 at 9-10.

23 Tr. 9/11/08, at 74-75.

24 See, e.g., Exh. DIV-31.

25 Exh. Div-5, at Schedule JAR-7; Exh. NGRID-9, at 14; Tr. 9/10/08 at 12-13.

26 Exh. DIV-31, at 4-5.

27 Id.

28 Id. at 17-18; Tr. 9/10/08 at 10-11, 50-52.

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 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 increases National Grid's consolidated common equity ratio determined in accordance with US GAAP by approximately eight percentage points.[29]

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.[30] 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.[31] These cash balances should have been subtracted from outstanding debt balances to compute the capital structure ratios, but were not.[32] 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 witness.[33]

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29 Exh. NGRID-9, at 17-18.

30 Id., at 15.

31 Id.

32 Id., at 15-16.

33 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.[34] 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.[35] The witness testified that he felt he was on "comfortable ground" with the "end result" without knowing anything about the RAV.[36] 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 witness.

Lastly, it should be noted that the Commission's ratemaking precedent has consistently used a utility's actual capital structure in setting rates, unless that capital structure is not reasonable for rate-setting purposes. When the situation arises where the actual capital structure is not reasonable for rate-setting purposes, the Commission has approved the imputation of a capital structure consistent with the market's expectations for a regulated utility. See, e.g., Blackstone Valley Electric, Order No. 13877 (1992) (using actual capital structure); The Narragansett Electric Company, Order No. 14857 (1995) (settlement using the actual capital structure of Narragansett Electric Company); The Narragansett Electric Company, Order No. 16200 (2000) (settlement agreement using 50/50 imputed capital structure); and The Narragansett Electric Company, Order No. 18037)(2004) (distribution rate settlement establishing imputed capital structure with 50% common equity, 45% debt and 5% preferred stock). The Company's recommended capital structure is consistent with this approach.

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34 Tr. 9/10/08 at 193.

35 Id. at 194.

36 Id. at 194-195.

Given the record evidence revealing the flaws inherent in the Division's analysis of capital structure and the fact that the result is completely out of line with market expectations for a regulated gas utility, there is no legitimate basis upon which the Commission could establish a common equity ratio of 37.77%. Conversely, the record is uncontested that the Company's calculation accurately reflects the average common equity ratio of the proxy group (and the proxy group is consistently used for both the capital structure and ROE calculation). Thus, the record evidence in this proceeding supports a finding that the common equity ratio used for ratemaking purposes should be 47.71%.

- *Recommended Statement of Findings*

1. The record shows that the capital structure for National Grid plc is inappropriate for use in setting the rates for a Rhode Island regulated gas company.

2. The record shows that the Division's recommended common equity ratio falls well below any ratio approved for other regulated utilities (gas or electric) and is not consistent with market expectations.

3. The record shows that the Division's recommended common equity ratio is not accurately computed given, among other things, the need to adjust for UK regulatory structure.

4. The record shows that the Company's actual capital structure is predominantly comprised of equity and therefore is not appropriate for use in setting rates. The record further shows that, for this reason, the capital structure must be imputed to remain consistent with market expectations.

5. The record evidence in this proceeding demonstrates that the Company has accurately calculated the average common equity ratio for the proxy group.

6. The record evidence shows that the average common equity ratio for the proxy group is 47.71% and that this ratio is consistent with market expectations for regulated gas companies.

7. Therefore, the authorized capital structure used for setting rates in this proceeding shall be comprised of 40.63% long-term debt, 11.66% short-term debt and 47.71% common equity.

C. Return on Common Equity

- *Summary of Company Proposal*

In its rebuttal case, the Company proposed a weighted average cost of capital of 9.19% and a return on common equity of 11.50%.[37] The cost of common equity was derived by the Company using capital market and financial data for natural gas utilities.[38] The Company performed a measurement of the cost of equity based on four recognized measures, which are the Discounted Cash Flow ("DCF") model, the Risk Premium ("RP") analysis, the Capital Asset Pricing Model ("CAPM") and the Comparable Earnings ("CE") approach.[39] The Company performed his measurement of these four methods using market and financial data for a proxy group of seven natural gas companies.[40] With a focus on the market model approaches (DCF, RP and CAPM), the Company calculated that the average equity return is 11.58%, and therefore, the Company proposed a cost of common equity of 11.5%.[41]

- *Discussion of Record Evidence*

The Division's witness recommended a weighted average cost of capital of 8.56% for National Grid with a return on common equity of 9.95%, which the witness stated would decline to 9.50% if the Commission were to adopt the Company's proposed capital structure with a higher proportion of common equity.[42] The Division used a proxy group approach for determining the recommend return on common equity, but was inconsistent in *not using* the

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37 Exh. NGRID-8, at Vol. 2, at 41.

38 Id.

39 Id.

40 Id. at 45.

41 Id. at Vol. 2, at 46-47.

42 Exh. DIV-5, at 4.

average capital structure of that proxy group as the basis for his recommendation on capital structure.[43]

In terms of the mechanics of the calculations put forward by the ROE witnesses, the record shows that there are a number of judgments and adjustments that each witness has made to produce a recommended return on equity at opposite ends of a spectrum. However, a number of overriding considerations relating to the Commission's final determination on ROE in this proceeding exist in the record. In particular, the Company demonstrated that the rate of return on common equity calculated by Mr. Rothschild is inordinately low and does not come close to the returns actually expected by investors for natural gas distribution utilities.[44] The record evidence supporting this conclusion is as follows:

First, Mr. Rothschild's recommendation for the return on common equity is based on the DCF model. The key to Mr. Rothschild's DCF analysis is his use of the "retention growth rate" method, which requires an assumption on the return on book common equity for a proxy group.[45] Mr. Rothschild selected 12% as his key input value, which was the second lowest value in his data set of 10 values.[46] This approach introduced a "significant downward bias" causing the DCF results to be biased and unreasonably low.[47] To be valid, Mr. Rothschild should have selected a balanced approach using a measure of central tendency, such as an average of the values, the median or a midpoint.[48] A balanced approach would have resulted in a higher value

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43 Exh. DIV-5, at 7.

44 Exh. NGRID-9, at 5; Exh. DIV-31.

45 Exh,. NGRID-9, at 22-23; Tr. 9/12/08 at 22-24.

46 Id.

47 Id.

48 Tr. 9/12/08 at 22-24.

comparable to the Company's calculation (such as 10.25%, 10.03% and 10.68% depending on the choice of central tendency measure).[49]

Second, the rate of return on common equity calculated by Mr. Rothschild 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.[50] 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.[51] 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.[52]

Third, the rate of return calculated by Mr. Rothschild 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.[53] In that regard, neither the testimony of Mr. Rothschild nor Mr. Moul have fully captured the effect of the most recent events in the financial markets; however, the Company is facing a significant challenge in terms of assuring investors that their capital is safe with the Company.[54] 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.

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49 Id.

50 Id. at 5; Exh. DIV-31.

51 Exh. NGRID-9, at 5 (Public Utility News, dated December 28, 2007)

52 Exh. DIV-31 (Regulatory Research Associates, dated July 2, 2008)

53 Exh. NGRID-9, at 6-8; Tr. 10/22/08 at 21-22, 66-67.

54 Exh. DIV-69.

Lastly, Mr. Rothschild 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 his proposal to set rates based on National Grid plc's lower common equity ratio. In its rebuttal, 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.[55] 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.[56]

The Company has made it clear from the outset of the proceeding that it is vital that a fair and reasonable rate of return be set in this proceeding in order to facilitate the Company's efforts to attract low-cost capital to support investment in the State of Rhode Island.[57] The record shows that ratings agencies and market analysts who review and comment on the Company's financials will take note of the decisions made by the Commission in relation to the authorized rate of return and capital structure.[58] For this reason, and based on the strength of the record evidence indicating that the Division's recommendations on ROE are inordinately low by any measure.

- *Recommended Statement of Findings*

Based on the foregoing, the Company recommends that the Commission make the following findings in relation to the allowed return on common equity:

1. The record shows that the Company's empirical analysis has resulted in the calculation of a common cost of equity of 11.5% based on a proxy group of comparable regulated gas companies.

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55 Exh. NGRID-9, at 37.

56 Id., at 3.

57 See, e.g., Tr. 9/10/08, at 74-78; Tr. 10/22/08.

58 Id.

2. The record demonstrates that the Division's recommendation for the allowed rate of return on common equity is inordinately low and is not reasonably calculated to provide the Company with a reasonable return on its investment or to attract capital to the State of Rhode Island to support needed investment on the distribution system.

2. The record demonstrates that the ongoing economic crisis and credit constraints is having the effect of increasing the cost of equity capital to account for increased risk and that this increase is estimated at 50 to 100 basis points.

4. The record demonstrates that if the Commission sets rates based on National Grid plc's equity ratio of 37.77%, the return on common equity authorized in this proceeding should include an upward adjustment of 98 basis points to compensate investors for the higher financial risk of an equity ratio that is substantially below the average of the Company's peers.

4. The record demonstrates that authorized rates of return on common equity for regulated gas distribution companies has been in the range of 10.24% to 10.35% in the past 18-24 months and that setting a rate of return at a point that is lower than average will be viewed as a negative by financial analysts.

5. The authorized rate of return on common equity shall be 11.5% for the purposes of establishing a revenue requirement in this proceeding.

D. Rate Base Additions through the Rate Year

- *Summary of Company Proposal*

The Company proposed a rate base of $285,241,458, which is based on a five-quarter average for the rate year with $589,768,959 for gas plant in service.[59]

- *Discussion and Review of Record Evidence*

The Division argued that the Company's actual rate of capital spending in the current fiscal year is lower than the Company's forecasted spending through the Rate Year, and that the Company is overstating its capital additions based on those actual expenditures.[60] Therefore, the Division recommended a reduction in forecasted capital additions through the rate year of $15,236,000 which a resulted in a proposed reduction of $10,259,000 to average rate year plant

[59] Exh. NGRID-3 at 44 (Attachment NG-MDL-1, at 24).

[60] Exh. DIV-1, at 20-23.

in service. This proposed reduction in plant in service also resulted in a reduction in average accumulated depreciation for the rate year amounting to $278,000. The Division's proposed net rate base adjustments amount to $9,980,000, for a total proposed average rate year rate base of $275,261,000.[61]

The Division's recommendation stems exclusively from two record requests, which ask the Company to compare budgeted capital spending to actual capital spending since the end of the test year October 31, 2007. The Company's response to Data Request DIV-1-2 showed that, as of March 31, 2008, actual spending was below budget by $3,449,377 (or $17,808,930 in budgeted spending versus $14,359,533 in actual spending). The Company updated its response to Data Request DIV-1-2 in Data Request DIV-13-4 showing that actual spending as of July 31, 2008 was below budget by $5,621,231 (or $30,389,150 in budgeted spending versus $24,767,919 in actual spending). Although the Company understands the Division's concern, the comparison of actual versus budgeted spending in the particular months included in the responses to Data Request DIV-1-2 and Data Request DIV-13-4 is not indicative of the level of spending that will be achieved through March 31, 2009, which is the basis for the Company's rate base adjustment.

As an initial matter, the Division's position depends on a "linear" amount of monthly spending through the fiscal year end. However, the Company's witness, Susan Fleck, testified that there was a lag in contractor billing and a need to ramp-up activities, which caused spending to be slightly below forecasted amounts in the early months of the financial cycle, but that spending would ramp up by the end of the cycle.[62] The witness also testified that the Company expected that by the end of the year the forecasted amount for capital spending would be

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61 Id at 23-24 (Schedule DJE-7).

62 Tr. 9/9/08, at 9-10, 12.

achieved.[63] There was no other evidence offered to contradict this testimony. Thus, the Company has provided a full and complete answer to the Division's concern. The Company will spend the forecasted amounts and there is no evidence in the record to support any other conclusion. For that reason, the Company's rate base is reasonable, supported by the record, and should be approved by the Commission.

- *Proposed Statement of Findings*

Based on the foregoing, the Commission should allow the Company's rate base amount, based on the following statement of findings:

1. The record shows that the Company will meet its forecast for capital spending by the end of the year.

2. The rate year rate base amount included in the Company's revenue requirement is approved.

OPERATING EXPENSES

E. FAS 112 Expense

- *Summary of Company Proposal*

The Company is proposing to include $740,000 in operating expenses relating to FAS 112 in the allowed revenue requirement. FAS 112 expense is the normal and recurring cost of extending post-employment benefits to the Company's internal workforce, and therefore is properly includable in rates. Accordingly, the Commission should allow for the inclusion of this legitimate utility expense in rates.

- *Discussion and Record Evidence*

Subsequent to the filing of the base-rate petition, the Company discovered that it had not accrued expenses related to FAS 112 for the test-year ended September 30, 2007, and therefore,

[63] Tr. 9/9/08, at 9-10.

these normally recurring expenses were not reflected in the proposed revenue requirement.[64] FAS 112 is the accounting standard that governs the calculation of the expense incurred by the Company to provide post-employment benefits, such as short-term and long-term disability benefits and health care costs associated with employees and their qualified dependents and/or beneficiaries.[65] The Company raised the issue of the need to correct the FAS 112 expense in its rebuttal testimony and stated that, although it did not agree with the Division's recommended adjustment to medical and dental expense, it would forego further debate on the medical and dental expense adjustment in consideration of the need to add FAS 112 expense to the revenue requirement.[66] Based on the similarity of the Division's proposed adjustment to health care expenses, ($907,456) and the Company's original estimation of FAS112 expense, $912,846, the Company's rebuttal position was to make no adjustment to the cost of service.

The accrual for FAS 112 expense for the fiscal year end (March 31) is based on census data from the beginning of the prior calendar year (i.e., January 1 of previous year). Thus, the FAS 112 accrual for FY2007 was based on census data as of January 1, 2006, which was prior to National Grid's acquisition of the Rhode Island gas assets.[67] Consequently, the Rhode Island gas employees were not included in the National Grid census data as of January 1, 2006. In addition, FAS 112 liability for all active claimants of the National Grid - RI Gas operations as of the acquisition date (August 24, 2006) was retained by Southern Union.[68] The combination of these

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64 Exh. NGRID-4, at 4-5; Tr. 9/8/08 at 89-92.

65 Id.

66 Exh. NGRID-4, at 3-4; Tr. 9/8/08.

67 Exh. DIV-28 (Data Request DIV-13-2); RR-COMM-5.

68 Id.

two factors led to an inadvertent mistake in accruing FAS 112 expense for FY2008, which was discovered just prior to the filing of the Company's rebuttal testimony.[69]

To demonstrate that FAS 112 expense should be included in the revenue requirement, the Company produced its most recent actuarial report dated December 19, 2007, for the 12-months ended March 31, 2008, indicating that the FAS 112 expense for the Rhode Island gas operations for FY 2008 amounted to $912,846.[70] In response to concerns raised by the Division regarding the possibility of a "catch-up" amount being included in that total, the Company determined that a FAS 112 liability of $169,532 existed as of April 1, 2007.[71] This liability should have been accrued in FY2007 representing the period August 24, 2006 to December 31, 2006.[72] Instead, that amount was accrued in FY2008. Had this accrual been recorded in FY2007, the FY2008 expense accrual would have been reduced by a like amount.[73] Consequently, the Company revised the FAS 112 revenue-requirement adjustment to $740,000 rather than the $912,846 amount originally estimated for FAS 112 expense with which the Company proposed to offset the Division's health care expense adjustment of ($907,456) in the Company's rebuttal position.[74] Subsequent to its rebuttal filing, the Company has adjusted its revenue requirement request for the difference of the Division's proposed health care expense adjustment of ($907,456) and the revised FAS 112 expense amount of $740,000, or a net reduction of $157,456 to the Company's rebuttal revenue requirement.[75]

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69 Id.; Exh. DIV-28 (Data Request DIV-13-3); RR-COMM-5; Tr. 9/8/08 at 89-92.

70 Exh. NGRID-4, at 5, and Attachment NG-MDL-Rebuttal-2.

71 Exh. DIV-28 (Data Request DIV-13-2); RR-COMM-5; Tr. 9/8/08 at 89-92, 94-96.

72 Id.

73 Id.

74 Id.

75 Id.

Although it is not completely clear, the Company believes that the Division no longer opposes this adjustment,[76] which is consistent with the testimony of the Division's witness agreeing that FAS 112 expense is an acceptable expense normally recovered by utilities.[77] The Division's only concern appeared to be the belief that the original amount cited by the Company is not representative of the level of expense that the Company would incur on a going-forward basis because it likely included a "catch-up" amount.[78] The record evidence demonstrates that the Company identified and removed the "catch-up" portion, isolating the annual expense amount to $740,000.[79] The record shows that this amount is representative of the level of expense the Company will incur on a going forward basis for the Rhode Island gas operations and there is no evidentiary basis for a finding to the contrary.[80] Accordingly, the Commission should allow FAS 112 expenses of $740,000 to be included in the allowed revenue requirement.

- *Statement of Recommended Findings*

Based on the foregoing, the Company recommends that the Commission make the following findings in relation to the FAS 112 expense:

1. The record evidence shows that FAS 112 expense is a normal, recurring expense associated with employee benefits, and therefore is properly includable in rates;

2. The record evidence shows that the Company has removed any "catch-up" amount resulting from the inadvertent error in recording FAS 112 expense following the acquisition of the Rhode Island operations from Southern Union Company;

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[76] During evidentiary hearings, the Company requested that the Division respond by record request as to whether it had further concerns about the FAS112 expense adjustment and has not received any response. Therefore, the Company is concluding that this issue may be resolved.

[77] Tr. 9/8/08 at 180.

[78] Exh. DIV-2, at 2; Tr. 9/8/08 at 176-181.

[79] Exh. NGRID-4, at 4-6 and Attachment NG-MDL-Rebuttal-2; Exh. DIV-28 (Data Requests DIV-13-2 and DIV-13-3); RR-COMM-5; Tr. 9/8/08 at 89-91, 95-97.

[80] Tr. 9/8/08 at 177. In fact, the Division's witness conceded that he was not familiar with all the assumptions and calculations that comprise the amount

3. The record evidence shows that the Company's estimated FAS 112 expense for FY2009 is $740,000, which is representative of the expense level that the Company will experience on a going-forward basis.

4. For these reasons, the FAS 112 expense is includable in the Company's allowed revenue requirement in the amount of $740,000.

F. Treatment of Merger-Related Synergy Savings

- *Summary of Company Proposal*

In the past, the Commission has allowed a 50/50 sharing of net merger-related operations and maintenance ("O&M") expense savings, with the Company's share recovered through a "line item" addition to the cost of service.[81] This policy recognizes that savings would not exist for customers in the absence of the shareholders' willingness to incur costs in order to complete a transaction that will result in consolidation opportunities that ultimately benefit customers. National Grid's acquisition of Southern Union's Rhode Island gas distribution operations was completed on August 24, 2006.[82] As a result of the transaction, National Grid was able to reduce three categories of corporate expenses including employee compensation associated with former New England Gas employees and corporate office expense.[83] Consistent with Commission precedent, the Company quantified the reduction in expenses made possible by the acquisition and included an amount equal to 50 percent of those cost reductions (net of integration costs or "costs to achieve" amortization) as an "add back" to the cost of service. This amount totals $1,054,609 and would be included in rates for a period of 10 years.[84]

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81 See, e.g., New England Gas Company, Docket 3401, Order No. 17381 (2002).

82 Exh. NGRID-3 (Vol. 1, at 61).

83 Exh. NGRID-3 (Vol. 1, at 60-64).

84 The original amount included in the proposed revenue requirement was $1,140,601 (Exh. NGRID-3 at Vol. 1, page 66). This amount was later reduced to $896,971 to account for an incorrect entry in the original calculation relating to test-year cost to achieve. (Exh. NGRID-4, at 13).

- *Discussion and Record Evidence*

As noted above, National Grid's acquisition of Southern Union's Rhode Island gas operations occurred on August 24, 2006.[85] Many operational changes occurred subsequent to the merger, which had the direct effect on three categories of costs: (1) labor expenses; (2) non-labor administrative and general expenses, and (3) expenses and the associated return related to offices of the former New England Gas Company, located on Weybosset Street in Providence, Rhode Island.[86] The Company examined cost levels in these three cost categories in two periods: July 1, 2005 through June 30, 2006 (the "pre-merger period") and October 1, 2006 through September 30, 2007 (the "post-merger period).[87] The pre-merger period coincided with the earnings-sharing period immediately preceding the merger, and therefore was a period where costs were subject to review by the Commission.[88] The post-merger period aligned with the end of the test year used by the Company in this case to develop the revenue requirement.[89] Thus, the Company's savings quantification was tailored to capture the specific and identifiable effects of merger consolidation.

Based on this analysis, National Grid calculated total annual merger savings of $2,439,354, with the costs to achieve these synergies totaling $158,152 based on a 10-year amortization.[90] The net amount equaled $2,281,201 and the Company included 50 percent of the net amount in its proposed revenue requirement, or $1,140,601.[91] On rebuttal, the Company recognized an error in the calculation, which had the effect of changing the total annual savings

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85 Exh. NGRID-3 (Vol. 1, at 61).

86 Id.

87 Id. (Vol. 1, at 61-62).

88 Id. (Vol. 1, at 61); see, New England Gas Company, Docket No. 3760, Order No. 18388 (January 24, 2007).

89 Id. (Vol. 1, at 62).

90 Id. (Vol. 1, at 64-65).

91 Id. (Vol. 1, at 65).

from $2,439,354 to $1,951,580, or $1,793,942 net of the annual amortization of costs to achieve.[92] Accordingly, the Company's rebuttal cost of service includes an add-back of $1,054,609, or 50 percent of the demonstrated cost reductions, plus the amortized amount of costs to achieve.[93]

The Division did not take issue with the Company's quantification assuming the use of the Company's methodology. Instead, the Division applied a different approach for calculating merger synergies and argued that, based on this approach, there are no merger synergies.[94] The Division's quantification methodology differed from the Company in two significant ways:

- The Division used the period July 1, 2002 through June 30, 2003 as the "pre-merger" period and the period October 1, 2006 through September 30, 2007 as the "post-merger" period ,[95] and
- The Division compared the total cost of service in these two periods, rather than looking at specific cost areas affected by post-merger consolidation.[96]

The Division stated that it took this approach because it was the method put in place for Southern Union to measure synergy savings in relation to its consolidation of the Valley Gas Company and Providence Gas Company, which occurred in 2001-02 and was an "agreed upon" benchmark, in existence prior to the NGRID/Southern Union transaction.[97] In addition, the Division stated that the approach was preferable because it constituted a "broad measure" of changes in the cost of service.[98]

However, from the Company's perspective, there are several problems with the Division's approach.

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92 Exh. NGRID-4, at 13; Attachment NG-MDL-Rebuttal-4.

93 Id.

94 Exh. DIV-1, at 14.

95 Tr. 9/8/08 at 184.

96 Exh. DIV-1, at 14; Schedule DJE-4.1.

97 Exh. DIV-1, at 14; Tr. 9/8/08 at 168.

98 Exh. DIV-1, at 14; Tr. 9/8/08 at 167-172, 183.

1. Use of the Year Ending June 30, 2003 for the Pre-Merger Benchmark

By using a 12-month period ending June 30, 2003 as the pre-merger measurement benchmark, the calculation of merger savings incorporates over three years of operation when National Grid did not own or operate the Rhode Island gas business. From the Company's perspective, this invalidates the integrity of the savings calculation because it imputes the effect of cost increases (or decreases) occurring under the ownership of Southern Union to the savings calculation, which would have a direct impact on the quantification of cost reductions achieved by National Grid. In fact, the Division's witness testified that, if measured against FY2006, "it's likely that almost anything you use would probably come up with some savings."[99] As the Company testified, this is because certain operating costs being incurred just prior to the merger were eliminated following the merger.

The reality is that, upon its acquisition of the Rhode Island operations in August 2006, National Grid inherited a given cost structure and the savings that it has achieved result from changes to that cost structure, not a cost structure in place over three years before and affected during the interim by Southern Union management decisions.[100] It is difficult to come to the conclusion that *no* cost reductions were achieved as a result of the merger when there has been a visible reduction in workforce and National Grid has emptied the corporate office building formerly occupied by New England Gas Company and arranged for its sale. In fact, the record is clear that cost levels in discrete cost categories are reduced from prior levels.[101]

Significantly, the Division's witness testified that the Company's use of a period ending June 30, 2006 as the pre-merger benchmark is "understandable," given the possibility that

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[99] Tr. 9/8/08, at 188.

[100] Tr. 9/8/08 at 104.

[101] Exh. NGRID-3 (Attachment MDL-1, at 5); Tr. 9/8/08, at 76-77.

increases in costs could have occurred under the prior ownership and that "arguably you could use the year ended June 2006 as a basis for making the test *if you had proper information*."[102] The Division advocates for the use of the year-ending June 2003 as the pre-merger benchmark on the basis that: (1) the use of the year-ending June 30, 2006 is problematic because expenses for that period "were unusually high and might not be indicative of the reasonable, normal level of ongoing expenses necessary to operate the business;"[103] and (2) the cost structure in the year-ending June 30, 2003 was based on a revenue requirement that was "explicitly approved by the Commission and had been verified as being expenses that were properly recoverable from customers in the revenue requirement."[104] However, each of these precepts should be examined carefully in determining the appropriate savings valuation method.

a. There is No Record Support Suggesting that FY2006 Is Inappropriate for Use as the Pre-Merger Benchmark Because of Unusually High Expenses.

The Division's claim regarding the existence of "unusually high" operating expenses in the 12-month period ending June 30, 2006 first arose in relation to the earnings-sharing calculation approved by the Commission in Docket 3760.[105] As an initial matter, it should be noted that the earnings-sharing proceeding involves a review of the Company's fiscal year revenues and expenses, which is the reason that the Company based its sharing calculation on the year ending June 30, 2006.[106] In the Docket 3760 proceeding, the Division argued that year-ending June 30, 2006 operating expenses were "unusually high" because distribution maintenance expense had increased by $1.9 million as compared to FY2005 and "customer

[102] Tr. 9/8/08 at 169, 182 (emphasis added).

[103] Exh. DIV-1, at 6; Tr. 9/8/08.

[104] Tr. 9/8/08 at 169.

[105] Exh. DIV-1, at 6.

[106] Exh. NGRID-3 (Vol. 1, at 61). However, the Company does not dispute that the review of expenses in an earnings sharing review is more limited than in a base-rate proceeding.

account" expenses relating to the cost of collection efforts and uncollectible expense had increased by $5.6 million also.[107] The Division testified that it did not find the Company's explanation of these increased expenses to be adequate and that "the increased level of expenses should be investigated and addressed when NGRID files its new rate plan, which will occur within a year of NGRID's acquisition of NEGas."[108]

In this case, the Division's witness is reiterating that the use of the year-ending June 30, 2006 as a pre-merger benchmark should not be used because costs in that time period were "unusually high;" however, the Division's witness also testified that a cost-comparison using the year-ending June 30, 2006 as a benchmark could be "useful" and could serve as the basis for making the savings test with the "proper information."[109] As an initial matter, it should be noted that neither distribution maintenance expense nor uncollectible expense represent expense categories included in the Company's merger-synergy analysis because these expense categories are not typically affected in the short term by merger-related consolidation.

Moreover, even if those expense categories were relevant, the Division has not developed any record evidence demonstrating that the year-ending June 30, 2006 cost information was somehow inaccurate or reflected unusual or unreasonably high costs. Although the Company has the burden in this proceeding of proving its case, it does not have the burden of proving that costs were *not* inappropriately high as of June 30, 2006. This is a claim that the Division has

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[107] See, Docket 3760, Order No. 18838, at 11 (January 24, 2007). Docket 3760 is referenced in the Direct Testimony of Mr. David J. Effron, Exh. DIV-1, at 6.

[108] Exh. DIV-2, at 6; Docket 3760, Order No. 18838, at 11. In Docket 3760, the Company's explanation of the increased expenses was that distribution maintenance expense included the cost of eliminating a backlog in Class I leaks, increased security services, and a change in the method of allocating supervisory labor time. Id., at 11-12. The Company explained that the $5.6 million increase in customer account expense related to increased collection efforts and an increase in uncollectible accounts expense of $3.8 million. Id.

[109] Tr. 9/8/08, at 182.

made and it is up to the Division to explore, evaluate and prove its claim that FY 2006 costs were inappropriately high, and therefore, should thwart the use of FY2006 as a pre-merger benchmark.

In that regard, the record in this case shows that distribution maintenance expenses were elevated in FY2007 in order to eliminate a backlog of leak repairs, which is the same reason that the Company cited in Docket 3760 for increased expenses in 2006.[110] In addition, the record shows that the Company's uncollectible ratio increased from 2.1 to 2.46 percent based on a historical five-year average. Thus, if anything, the record demonstrates that the "unusually high" costs referenced by the Division's witness in Docket 3760 are explainable and were not unreasonably or inappropriately incurred by the Company in FY2006. In any event, because these cost categories do not relate to areas where merger consolidation occurred, the "unusual" cost levels experienced in FY2006 should not cause FY2006 to be precluded from use as a merger benchmark, especially where the period would otherwise provide a sound basis for quantification of merger-related synergies.

b. The Background of the New England Gas Merger Savings Measurement Method Does Not Support Its Use in this Case.

The second basis for the Division's opposition to the use of the year-ending June 30, 2006 as the pre-merger benchmark is that the measurement method established for the former New England Gas Company in Docket 3401 is more appropriate because (a) its existence pre-dates the NGRID/SU transaction, and (b) it uses the cost structure existing in the year-ending June 30, 2003, which was based on a revenue requirement explicitly approved by the Commission and verified as including expense that were properly recoverable from customers.[111] However, the actual facts surrounding the measurement method established in Docket 3401 are

[110] Exh. DIV-8 (Data Requests DIV-1-28; DIV-1-29).

[111] Exh. DIV-1, at 14; Tr. 9/8/08 at 169.

more supportive of the Company's proposal in this proceeding than of the premise that merger savings can be properly quantified only when the measurement method pre-dates the transaction and is applied to an "explicitly approved" revenue requirement.

For example, Southern Union acquired the operations of Providence Gas Company, Valley Gas Company and Bristol and Warren Gas Company in a transaction that was approved by the Division on July 24, 2000.[112] The Division's approval of the transaction was based on a settlement agreement between the Division, New England Gas Company and several other parties (the "Merger Settlement Agreement").[113] No "measurement method" was in existence prior to the Southern Union acquisition of the Rhode Island gas companies, nor was a specific method established in the Merger Settlement Agreement.[114] Instead, the Merger Settlement Agreement obligated the Company to develop a consolidation plan that would identify estimated synergy savings and then to file a base-rate case incorporating those synergy savings into the cost of service in a manner that shared the projected savings between customers and shareholders.[115] The Company fulfilled these requirements with a base-rate filing on November 1, 2001, which included a revenue-requirement calculation incorporating projected annual merger savings.[116] The quantification of merger savings was not based on a formula comparing a pre-merger period to a post-merger period.[117] Instead, the quantification was based on a review of the specific cost categories that would be affected by post-merger consolidation.[118]

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112 Dockets D-00-2 and D-00-3, Order No. 16338 (July 24, 2000).

113 Id. at 62.

114 Id. at 61; Merger Settlement Agreement at 68-70.

115 Merger Settlement Agreement at 68-70.

116 Docket 3401, Order No. 17381, at 1, 4.

117 Id. at 5-6.

118 Id.

The rate case filed by Southern Union's new "New England Division" was resolved in Docket 3401 with the Commission's approval of a new settlement agreement (the "Docket 3401 Settlement") establishing a revenue requirement that shared projected savings between the New England Gas Company and customers on a 50/50 basis.[119] Customers received their share through a base-rate credit of $2,049,000, representing 50 percent of the anticipated consolidation savings.[120] The Company received its share through the earnings sharing mechanism, which was designed to allow the Company to include an expense line item totaling $2,049,000, so that earnings were not subject to sharing unless the Company had first covered its expenses, including the $2,049,000 line item.[121] The Company was allowed to include this amount in the ESM until the first base-rate proceeding occurring after the rate freeze period, which expired on June 30, 2005.[122]

The Docket 3401 Settlement Agreement also established a "savings proof," which is the "measurement method" used by the Division in this case to find that no savings occurred as a result of the NGRID/SU acquisition.[123] The savings proof was not used to quantify the savings arising from Southern Union's purchase of the Rhode Island gas companies – savings were quantified by analyzing the effects of consolidation and the expected impact was built into

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119 Docket 3401 Settlement Agreement at 1-2, 5, 12.

120 Id. at 1-2. In that case, consolidation activities largely commenced after the test-year period. Therefore, savings were not reflected in the test-year booked amounts. Instead, the revenue requirement was reduced by the customer share of expected synergies savings (50 percent), which is analogous to the treatment afforded to the NGRID/KeySpan savings in this docket.

121 Id. at 12.

122 Id.

123 Id. at 13-15. See, Exh. DIV-1, at 13-14.

rates.[124] The savings proof had no effect prior to the expiration of the rate freeze on June 30, 2005.[125]

This context is important for three reasons. First, it is significant that the "measurement method" supported by the Division in this proceeding as an "agreed upon" approach was agreed to by the parties in prior settlements (involving a number of trade-offs among the parties) for the purpose of creating a "savings proof" for future ratemaking proceedings, and not as a methodology to quantify the underlying consolidation savings. As a savings proof, the methodology is intended to measure whether the overall cost of service is lower in the future than it otherwise would have been had the merger not occurred. Through the application of a savings proof, shareholders are required to prove that *continued* recovery of merger related savings from customers is justified.[126] Because this methodology measures the total cost of service, it is not amenable for use in quantifying specific consolidation savings, which is the reason that consolidation savings have been quantified in the past on a category-by-category basis.

It is also relevant that the synergy quantification in Docket 3401 was included in the Commission-approved revenue requirement following an investigation *within the base-rate proceeding* of the nature of the consolidation savings and without a prior investigation into the pre-merger cost structure to prove that the pre-merger costs were "properly recoverable" from customers.[127] As a result, the Division's proposition in this case that the measurement method must be in existence prior to the transaction and that it should be based on a pre-merger revenue

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124 Docket 3401, Order No. 17381, at 5-6, 44, 52; Docket 3401 Settlement Agreement at 1-2, 12.

125 Docket 3401 Settlement Agreement at 13-14.

126 Docket 3401, Order 17381, at 64 (stating: "[t]he Final Amended Settlement for NEGas has reasonable procedures and standards for determining merger savings *after the rate freeze period*. This is an effective tool for keeping rates down, placing the burden upon the utility *to prove* its merger savings" (emphasis added).

127 See, Exh. DIV-1, at 14; Tr. 9/8/08 at 169, 170-172.

requirement "explicitly approved by the Commission," represents a set of prerequisites that did not apply in prior mergers and is not necessary in order to identify costs that have been eliminated through consolidation.[128]

Lastly, it should be noted that the record in this case reflects the fact that National Grid properly applied the Docket 3401 savings proof to determine whether it could propose to continue to include the Company's share of Southern Union savings ($2,049,000) in this rate case, as allowed by Paragraph I.G.2 of the Docket 3401 Settlement Agreement.[129] The savings proof indicated that the Company was not entitled to seek continued recovery of its Docket 3401 savings through rates, and therefore, the Company excluded this amount from the base-rate request.[130]

2. Comparing the Total Cost of Service Rather than Cost Areas Affected By Merger Consolidation

A second difference between the Company's calculation of NGRID/SU merger savings and the Division's calculation is that the Division's recommended methodology compares the total cost of service in a pre-merger period (2003) to the total cost of service in the post-merger period (2006). Again, comparing the total cost of service may make sense when the exercise is to verify that the overall cost of service is lower than it would have been absent the merger, thereby justifying continued recovery of synergy savings by the Company and its shareholder. However, this approach is flawed when applied to quantify specific cost savings resulting from post-transaction consolidation.

The fundamental problem with a total cost of service approach is that it captures cost fluctuations (upward and downward) that occur in cost categories unaffected by post-transaction

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128 See, id.

129 Exh. NGRID-4, at 11.

130 Id.

consolidation activities.[131] The Company testified that there are a number of O&M cost categories that experienced increased spending following the merger as the Company ramped up its activities to eliminate the leak backlog and make progress on other distribution maintenance activities to improve the safety and reliability of the system after several years of under-investment.[132] If the Company is spending more than the prior owners on activities necessary to maintain and improve the safety and reliability of the system, that spending should not detract from the quantification of savings in other cost categories resulting from post-transaction consolidation because it is, in effect, penalizing the Company for doing its job. As in prior mergers, the Company quantified merger savings by evaluating the particular cost categories affected by consolidation including labor, non-labor administrative and general expenses and office building expense. This approach is entirely consistent with past quantifications of merger synergies and eliminates the possibility that the quantification is capturing cost trends that are unrelated to the consolidation.

Aside from the Division's recommendation that an entirely different measurement method be applied, there is no record evidence contesting the Company's calculation of consolidation savings. Thus, the decision before the Commission is whether the Company's measurement method is reasonable and appropriate or whether another methodology is better supported by the record. In that regard, the record shows that the Division's methodology produced a result that *zero* merger savings were realized despite testimony from the Division's witness that some level of merger savings have occurred.[133] This is an inconsistency that significantly undermines the validity of the methodology recommended by the Division and that

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131 Tr. 9/8/08 at 113-114.

132 Tr. 9/8/08 at 113-114, 117.

133 See, Tr. 9/8/08 at 187-188.

arises from the inappropriate use of the measurement methodology agreed to in Docket 3401. Alternatively, the Company's methodology is precise and straightforward, as well as being fully consistent with past practice for the quantification of merger-related consolidation savings. Accordingly, the Commission should allow the inclusion of $1,054,609 in the revenue requirement so that the Company is allowed to recover a 50 percent share of the savings it has achieved as a result of its acquisition of Southern Union's Rhode Island gas operations.

- *Summary of Recommended Findings*

Based on the foregoing, the Company recommends that the Commission make the following findings in relation to the quantification of NGRID/SU merger synergies:

1. The application of the Division's recommended measurement method is not reasonable or supported by record evidence because it uses a pre-merger benchmark of the 12-months ending June 30, 2003;
2. The application of the Division's recommended measurement method is not reasonable or supported by record evidence because it does not isolate the cost areas subject to consolidation;
3. The record does not contain any evidence demonstrating that the 12-month period ending June 30, 2006 is inappropriate for use as a benchmark in quantifying merger synergies, or that it is necessary to require the savings to be quantified based on reductions from an approved revenue requirement.
4. The Company has demonstrated that, if merger synergies are quantified by comparing costs for labor, non-labor administrative and general expense and office building expense in the 12-month period ending June 30, 2006, as compared to the 12-month period ending September 30, 2007, merger synergies total $1,951,580, or $1,793,942 net of the annual amortization of costs to achieve. The record shows that the annual amortization of the cost to achieve merger savings is $157,638.
5. The record evidence shows that 50 percent of the quantified net savings is $896,971 and that this amount, plus the annual amortization of the costs to achieve the merger synergies, or $1,054,609 should be included in the revenue requirement in order to provide the Company with its share of the achieved merger savings.
6. A total of $1,054,609 shall be included in the approved revenue requirement and the Company shall be authorized to create a regulatory asset in accordance with FAS 71 to account for the levelized amortization of the costs to achieve over a 10-year period.

7. During the ten years, the Company shall be allowed to reflect its share of the savings in annual earnings reports filed with the Commission for earnings sharing purposes.

G. Additional Findings Relating to Treatment of Merger-Related Consolidation Savings for the NGRID/KeySpan Merger

During the proceeding, the Company and the Division reached agreement on the treatment of merger savings relating to the NGRID/KeySpan merger, which were estimated to be $6,400,000 in the fourth year following the merger.[134] Specifically, the Company and the Division agreed to include an advance base-rate credit of $2.45 million in the revenue requirement for the benefit of customers to reflect a 50% customer share of projected "steady state" net merger savings.[135] In addition, the Company would be entitled to include its 50% share of the savings in the cost of service in any rate case filed in the first five years following the effective date of the Commission's order in this case, by adding a line item cost of $2.45 million in the cost of service. After five years and continuing through the tenth year, the Company would still be entitled to include a 50% share of savings in the cost of service in any filed rate case subject to a savings proof. The proof of savings would be based on a comparison of pre-merger total operations and maintenance expenses, as escalated for inflation, versus the total rate year operations and maintenance expenses being proposed in any rate case filed during that five year period.[136] 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. This period aligns reasonably close with the most recent twelve month period immediately preceding the National Grid/KeySpan merger which closed in

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134 Tr. 9/8/08, at 71-72.

135 Id.

136 Id.

August 2007.[137] During the ten years, the Company would be allowed to reflect its share of savings in annual earnings reports filed with the Commission.

To implement the agreement, and to provide for the appropriate accounting treatment of costs to achieve and associated amortization, the Company requests that the Commission to make the following findings:

1. The Company has demonstrated that merger savings totaling $6,400,000 are projected to result from the NGRID/KeySpan merger transaction. The record also shows that the annual amortization of the cost to achieve merger savings is $1,500,000.

2. The record evidence shows that 50 percent of the quantified net savings ($6,400,000 – $1,500,000 = $4,900,000) is $2,450,000 and that this amount should be included in the revenue requirement as a base-rate credit in this proceeding in order to provide the customers with a 50% share of synergies projected to result from the transactions.

3. The Company shall be entitled to include its 50% share of the savings in the cost of service in any rate case filed in the first five years following the effective date of the Commission's order in this case, by adding a line item cost of $2.45 million in the cost of service. After five years and continuing through the tenth year following the effective date of the order in this case, the Company shall still be entitled to include a 50% share of savings in the cost of service in any rate cases filed, subject to a savings proof. The proof of savings would be based on a comparison of pre-merger total operations and maintenance expenses, as escalated for inflation, versus the total rate year operations and maintenance expenses being proposed in any rate case filed during that five year period[138] 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. This period aligns reasonably close with the most recent twelve month period immediately preceding the National Grid/KeySpan merger which closed in August 2007

4. During the ten years, the Company shall be allowed to reflect its share of the savings in annual earnings reports filed with the Commission for earnings sharing purposes.

5. The Company shall be authorized to create a regulatory asset in accordance with FAS 71 to account for the levelized amortization of costs to achieve over a 10-year period to be included in its cost of service.

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137 Id.

138 Id.

H. Gas Marketing Program

- *Summary of Company Proposal*

The Company is proposing to establish a Gas Marketing Program and to include program costs totaling$1,377,000 in the allowed revenue requirement.[139] The purpose of the program is to encourage migration to natural gas service from other fuel sources so that the fixed costs of the distribution system would be spread across a larger customer base over time.[140] The Gas Marketing Program is targeted at converting residential and commercial and industrial ("C&I") customers who are located on the existing distribution system and are either not currently taking gas service or are taking service as low-use, or non-heating customers.[141] Program funds would be used for three purposes: (1) to offer rebates and incentives to customers to help abate the cost of converting to gas service ($698,798); (2) to conduct customer outreach and communication to educate customers about the possibilities of converting to gas service ($528,000), and (3) to support the program administration ($150,000).[142] The Company views the Gas Marketing Program as vital in (1) controlling distribution prices over the long-term; (2) offsetting the effects of customer conservation, and (3) serving environmental goals.[143]

No party submitted testimony opposing the introduction of the Gas Marketing Program apart from the Division, who recommended a reduction of the allowable program expenses from $1,377,000 to $148,000. The Division's concerns are discussed below and may have been resolved through hearings; however, the Company believes that the record evidence supports the Commission's approval of the program and that it would be in the public interest to do so.

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139 Exh. NGRID-6, at Vol. 2, at 35-37.

140 Exh. NGRID-6, at Vol. 2, at 7.

141 Exh. NGRID-6, at Vol. 2, at 17.

142 Exh. NGRID-6, at Vol. 2, at 29-30; Exh. DIV-8 (Data Request DIV-1-20).

143 Exh. NGRID-6, at Vol. 2, at 31; Tr. 10/22/08 at 171.

Accordingly, the Commission should allow for the inclusion of $1,377,000 in program expenses in rates.

- *Discussion of Record Evidence*

There does not appear to be any dispute in this proceeding that expanding the customer base is beneficial to all customers because it means that, in the ratesetting context, there are a greater number of billing units across which fixed costs are spread. In fact, the rate design proposed by the Company at the outset of this proceeding incorporates the volumes that the Company projected would be added through the end of the Rate Year as a result of the Gas Marketing Program and the Division has advocated to retain these volumes in rates, even if the program is denied.[144]

Therefore, as the Company understands it, the Division's opposition to the Gas Marketing Program is based on two precepts, which are that: (1) the existing differential between the price of natural gas and oil negates the need for "heavy marketing," because high oil prices reinforce the "economic attractiveness" of natural gas service,[145] and (2) various aspects of the program may have anti-competitive implications.[146] However, the record shows that the Gas Marketing Program is needed to overcome obstacles that discourage gas conversions; that it will produce significant benefits for existing customers in terms of spreading fixed costs; that customers want the Company to provide this service (and that it is probably long overdue in that regard), and that the concerns about the program's "anti-competitive" effects are unwarranted.

With respect to the differential between oil and natural gas prices, the Division's witness testified at length as to his predictions on the future of oil and gas prices, with the overall

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144 Exh. NGRID-6, Vol. 2, at 30; Exh. DIV-4, at 32-33.

145 Exh. DIV-3, at 20-21.

146 Id. at 28.

conclusion being that natural gas has a significant price advantage and will hold that advantage from this point forward.[147] However, the Division's analysis goes no further than this conclusion. The Division did not perform any analysis of the number of conversions that would occur because of the oil price differential in order to prove its assertion, nor did the Division attempt to investigate or demonstrate that the number of conversions achieved without the program would match or exceed the number identified by the Company as occurring with the program.

Moreover, the Division's proposition is based on the premise that the differential between oil and natural gas creates a "payback" that will motivate heating conversions without the need for a marketing effort,[148] but the Division never addressed the fact that the "payback" comes over time after the payment of a significant up-front incremental investment, which is required by customers to convert to natural gas rather than remaining with their existing fuel service (probably oil) when replacing or upgrading their existing heating equipment.[149] This up-front cost generally exceeds $2,000 for a residential customer and *is not incurred* if a customer sticks with their existing fuel source rather than converting to natural gas.[150] Therefore, this incremental investment poses a significant obstacle for many customers, especially for residential customers who are already facing a significant cost in replacing their heating equipment, regardless of fuel choice.

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147 See, e.g., Tr. 10/21/08 at 66-72.

148 Exh. DIV-3, at 21.

149 Exh. NGRID-6, at 10-11; Exh. DIV-17 (Data Request Div-8-7).

150 See, Tr. 9/8/08 at 11 (testimony of Rhode Island Oil Heat Institute, stating that "it is less costly for the oil heating customer to upgrade their existing system with new efficient oil heating systems").

The Company has emphasized in this proceeding that the Gas Marketing Program is designed to operate regardless of prevailing market prices for oil and natural gas.[151] The record shows that the focus of the program is to address the factors that create obstacles to customer conversions, which exist at all times, not simply when natural gas prices are higher than oil.[152] The Company's testimony is that natural gas and heating oil prices will fluctuate over time, with the price differential changing on a constant basis.[153] Thus, the program is designed to achieve growth in the number of customers regardless of the existence of a favorable cost differential, although a favorable cost differential inevitably will assist the Company in reaching *and exceeding* the program goals, which is a positive outcome for existing customers.

On that point, the record shows that the oil-to-gas price differential has motivated an incremental level of conversions, but that the price differential occurred at the same time that the Company rolled out its initial marketing efforts. The Company testified that, in its other jurisdictions where rate-funded gas marketing programs have existed for some time, the oil-to-gas price differential has caused about a 15 percent increase in the number of conversions, as compared to the number of conversions in prior years. For Rhode Island, where the Company commenced the Gas Marketing Program in late 2007 and early 2008, the record shows that conversions will increase by approximately 400 percent through the end of FY2009, with approximately 700 conversions completed in 2007 and 3,000 conversions expected by March 31, 2009.[154] As a result, while it is clear that the oil-to-gas price differential has had a positive impact on the number of conversions, it is also clear that the impact is greater when combined with the Gas Marketing Program.

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151 Exh. COMM-1 (Data Request COMM-1-23); Tr. 10/22/08, at 18.

152 Tr. 10/20/08, at

153 Exh. COMM-7 (Data Request COMM-3-8).

154 Exh. COMM-1 (Data Request COMM-1-23).

Second, in terms of a potential anti-competitive impact, it is necessary to sort through what the anti-competitive effect is that is causing a concern. The Division first claimed that National Grid's offering of heating equipment to prospective conversion customers "may have anti-competitive implications" because the Company would be purchasing and reselling heating equipment at "below market prices."[155] However, the record shows that the Company is making a bulk purchase of equipment 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.[156] The Company is not making any profit on the sale of equipment, nor is adding any type of markup.[157] 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.[158] 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 Division next appeared to be working on the theory that the program was anti-competitive because it would unduly benefit National Grid Energy Services ("NGES"), which is the Company's unregulated heating and cooling affiliate.[159] However, 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

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155 Exh. DIV-3, at 28.

156 Tr. 10/20/08.

157 Id.

158 Id.

159 Tr. 10/20/08.

other plumbing and heating contractors.[160] The record shows that out of all the conversions completed through the program, approximately 30 percent utilize a referral through the VPI Program.[161] 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.

One other issue is significant and should be mentioned. In its initial filing, the Company emphasized that customer additions accomplished through the Gas Marketing Program would be "cost-effective," meaning that the cost of adding customers through the program would be less than the revenue stream that would be generated by the customer over the customer "lifespan".[162] 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.[163] 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 (11.50%, if the Company's proposal is adopted), but customer additions completed through the program will produce a rate of return *in excess of that amount*.[164]

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

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160 Id.

161 Id.

162 Exh. NGRID-6, at Vol. 2, at 25-

163 Id. at 28.

164 Exh. NGRID-6, at Vol. 2, at 25-29.

will inure to the direct benefit of existing customers, who are credited with 50 percent of earnings in excess of the ROE and 75 percent of incremental earnings greater than 100 basis points above the allowed ROE. The Division's witness made no attempt to explore, understand or challenge this calculation, stating that "I don't put an awful lot of weight on those analyses [because] they are highly assumption driven."[165] However, the internal rate of return calculation is a routine and well-established methodology used within the gas industry to make determinations on the prudency of growth investments and is the same analysis used to calculate a customer's contribution in aid of construction.[166] As a result, there is no record evidence disputing or contravening the Company's IRR calculation, and therefore, the record shows that the Gas Marketing Program will produce substantial benefits for existing customers in terms of the earnings sharing mechanism.

Lastly, the Division stated that it would be necessary to require the Company to track and account for a number of aspects related to the program, including program spending and customer additions achieved, the use of funds collected from VPI participation fees, and the cost of any customer guarantees or remedial actions made necessary because of poor performance by a participating VPI installer. The Company has no objection whatsoever to these recording and reporting requirements and believes that the result will be to demonstrate the success of the program over time.

In the final analysis, the record shows that growth in the customer base benefits all customers over the long term, while the favorable cost-benefit balance associated with the Gas Marketing Program will directly benefit existing customers through the annual earnings sharing mechanism in the nearer term. There is no evidentiary basis to support the contention that the

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165 Tr. 10/21/08, at 62.

166 Exh. NGRID-6, at Vol. 2, at 27.

oil-to-gas price differential will continue, continue at the same level or produce the same or similar results as the Gas Marketing Program on a year-to-year basis. Similarly, the record does not support the conclusion that there is an anti-competitive effect on the marketplace as a result of program implementation. The record shows that the Gas Marketing Program is structured to educate customers on their conversion options and to assist in overcoming hurdles that exist and have the effect of discouraging gas conversions in the normal course of business. Accordingly, the Commission should approve the Gas Marketing Program and the recovery of program costs through rates set in this proceeding in the amount of $1,377,000 annually.

- *Statement of Recommended Findings*

Based on the foregoing, the Company recommends that the Commission make the following findings in relation to the proposed funding of the Gas Marketing Program:

1. Growth in the number of customers comprising the customer base is in the public interest;

2. According to the Company's IRR analysis, the cost of the program will be less than the revenue stream produced by customers added through the program implementation;

3. According to the Company's IRR analysis, the CIAC to be charged to customers following this rate case should be $450 for residential heating customers and $1,500 for residential non-heating customers, which represents reductions from the current level. The Company shall file a tariff governing the Contribution in Aid of Construction charge and establishing new CIAC charges with its compliance filing in this case.

4. There is no record evidence that any oil-to-gas price differential existing from time to time will produce the same level of customer additions as the Gas Marketing Program on a year-to-year basis;

5. The Company has demonstrated that the Gas Marketing Program is structured so as to provide no undue or inappropriate benefit to its unregulated affiliate.

6. The Company shall track costs and results in a manner agreeable to the Division, and as directed by the Commission, for reporting on an annual basis.

7. Based on the foregoing, the Gas Marketing Program is in the public interest and is approved. Therefore, program costs totaling $1,377,000 shall be included in rates set in this proceeding.

I. Rate Case Expense:

In the Company's initial filing in this proceeding, the Company provided a schedule of estimated rate-case expenses, which totaled $797,250.[167] The Company proposed a three-year amortization of these costs in rates with the annual amortized amount incorporated in the revenue requirement totaling $265,750.[168] However, the Company is also responsible for reimbursing the rate-case expenses of the Commission and the Division and the Company's estimated rate-case expenses did not include these amounts. The Commission has issued a data request for an update of the rate case expenses from both the Company and the Division. The Company proposes that the Commission incorporate the updated rate case expenses into the Company's revenue requirement, including (i) the Company's updated expenses, (ii) the Division's expenses that will be provided, and (iii) any expenses incurred by the Commission in this Docket that will be billed to the Company. Accordingly, the Company is requesting that the Commission make the following findings on rate-case expense:

1. Rate-case expenses are a necessary cost for the Company and recovery of reasonable rate-cases expenses is allowed through base rates under the Commission's precedent.

2. The Commission finds that the Company shall be allowed to recover the updated rate-case expenses in this case, as provided in the responses to the Commission's data request issued November 6, including the Company's updated expense amounts and the Division's expenses pursuant to their

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[167] Exh. NGRID-3, at 21 (Attachment NG-MDl-1, at 15, line 12).

[168] Id.

> response, as well as the Commission's expenses, over a three year period. The Company shall replace its originally estimated rate case expense amortization with the annual amortization of these updated total rate-case expenses in the revenue requirement based on a three-year amortization period.

III. NON-BASE REVENUE RECOVERY ITEMS

In this proceeding, the Company has made a number of proposals that would establish or modify rate recovery mechanisms that operate through the Distribution Adjustment Charge ("DAC") and the Gas Cost Recovery ("GCR") charge. In Sections IV.A, IV.B and IV.C, below, the Company discusses its proposals relating to the Accelerated Replacement Program (non-contested), the pension and post-retirement benefits other than pension reconciliation mechanism and its proposal to recover gas-cost related bad-debt expense on a reconciling basis, consistent with the Commission's policy on the recovery of gas-supply related costs. In Section IV.D, the Company sets forth a proposed statement of findings that relate to a number of uncontested, "housekeeping" matters that the Company raised in its initial filing in this proceeding. It should also be noted that, if implemented, decoupling revenues would be recovered through the DAC. However, the Company discusses the implementation in Section V, below, rather than including a discussion here.

A. Accelerated Replacement Program

- *Summary of Company Proposal*

In this proceeding, the Company proposed to implement an Accelerated Replacement Program ("ARP") to address critical infrastructure needs in the state of Rhode Island. Currently, the Company's distribution system encompasses 900 miles of cast-iron gas main and 440 miles of bare steel unprotected gas main, which together represent approximately 43 percent of the

gas-main network located in Rhode Island.[169] Of the 900 miles of cast-iron main currently in place, there are approximately 395 miles of small diameter cast-iron main, for which the Company has no designated program in place for systematic replacement.[170]

After acquiring the Rhode Island operations of Southern Union in 2006, the Company conducted a baseline system assessment, which determined that there is an unacceptable level of leaks in certain areas where cast-iron and unprotected bare steel piping is concentrated and that the rate of leaks is increasing.[171] The record shows that the leakage rate for Rhode Island is one of the highest in National Grid system and rising.[172] As a result, the Company decided that there was a need to substantially increase capital spending in two specific areas in order to maintain the safety and reliability of the system, which are: (1) the replacement of unprotected bare-steel pipe and small diameter cast-iron main, and (2) the elimination of high-pressure bare-steel services located inside customer premises.[173]

Through the ARP Program, the Company proposes to double the pace of its replacement of unprotected steel main, initiate a systematic replacement program for small diameter cast-iron main, and within the next five years, to eliminate 8,261 high-pressure, bare-steel inside services remaining on the system.[174] In terms of the current replacement schedule, the Company is replacing leak-prone unprotected steel and cast-iron pipe at a rate of approximately 13 miles per year (versus a total of 1,185 miles existing on system).[175] The Company is proposing to increase replacement to approximately 18 miles per year for these two categories of pipe combined. In

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169 Exh. NGRID-5, at 4, 8-10, 15; Exh. COMM-3 (Data Request COMM-2-7).

170 Exh. COMM-3 (Data Request COMM-2-7).

171 Exh. NGRID-5, at 8-10, 15.

172 Tr. 9/9/08 at 20.

173 Exh. NGRID-5, at 11.

174 Exh. NGRID-5, at 10-11, 22.

175 Exh. COMM-3 (Data Request COMM-2-7).

addition, the Company is proposing to replace an additional 5 miles per year of small diameter cast iron (4" and smaller), for a total of 23 miles per year (i.e., 18 miles plus 5 miles).[176]

As envisioned by the Company, the ARP Program will entail an annual filing of a Pipe Replacement Program Plan for Commission review and approval.[177] Also, there would be an annual reconciliation of capital expenditures made in accordance with the ARP Program plan.[178] The Company would recover annual amounts allowed under the plan on a reconciling basis through the DAC. As proposed by the Company, the ARP would entitle the Company to a rate adjustment for ARP investments only to the extent that the capital cost is incremental to the amount included in base rates set in this proceeding.[179]

The Company proposes to start the program for fiscal year 2009 (12-months ending March 31, 2009), with the first ARP reconciliation report due May 15, 2009 for a rate adjustment effective July 1, 2009.[180] The first planning report will be due January 15, 2009 for FY2010 (12-months ending March 31, 2010).[181]

- *Discussion and Review of Record Evidence*

Based on rebuttal and surrebuttal testimony, the Company and the Division are in agreement on the implementation of the ARP.[182] As part of this consensus, the Company agreed to certain modifications to the ARP at the request of the Division.[183] Specifically, the depreciation expense included in ARP will reflect the impact of plant retirements on a pro-rata

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176 Id.

177 Id. at 23-24; Tr. 9/8/08 at 80-82.

178 Id.; Exh. NGRID-4, at Attachment NG-MDL-Rebuttal-6.

179 Exh. NGRID-3, at 53.

180 Exh. NGRID-4, at 18.

181 Id.

182 Tr. 9/8/08, at 78; Tr. 9/9/08, at 227.

183 Tr. 9/8/08, at 78.

basis.[184] Also, the property tax rate included in the ARP will be based on the prior year's annual property tax expense to net plant in service and a composite depreciation rate will be applied for mains and services only.[185] Lastly, the Company will be allowed to recover only *incremental* replacement costs through the ARP, and will do so only to the extent that the Company's earned return in any year (as calculated for the ESM) is below the Company's authorized return on equity.[186] If approved, the Company plans to work closely with the Division and the Commission to shape and conduct the plan in a manner that best achieves safety and reliability goals.

- *Proposed Statement of Findings*

Based on the foregoing, the Company recommends that the Commission make the following findings in relation to the proposed funding of the ARP Program:

1. The record shows that a greater level of ongoing investment is needed to maintain the Company's aging gas infrastructure in a safe and reliable manner.

2. The record shows that a greater level of mains replacement will reduce leak rates and improve the safety and reliability of the system. The record further shows that a reduced leak rate will have a beneficial environmental impact.

3. The record shows that the ARP Program is the best means available to achieve a greater level of investment in critical infrastructure upgrades.

4. The record shows that the ARP Program will provide the Commission with adequate oversight opportunity to protect the interests of customers in terms of safety and reliability, balanced with cost.

4. For the foregoing reasons, the Company shall be authorized to implement the Accelerated Replacement Program, subject to the recommendations of the Division. The program will start with fiscal year 2009 (12-months ending March 31, 2009), with the first ARP reconciliation report due May 15, 2009 for a rate adjustment effective July 1, 2009. The first planning report will be due January 15, 2009 for FY2010 (12-months ending March 31, 2010).

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184 Exh. DIV-1, at 28-29; Exh. NGRID-4, at 17-18; Tr. 9/8/08, at 78-83.

185 Id.

186 Id.

B. Gas-Supply Related Bad Debt Cost

- *Summary of Company Proposal*

Currently, the Company recovers gas-cost related bad debt as a result of a fixed, five-year average bad-debt ratio, which is set in a base-rate proceeding and then applied to total gas revenues in each GCR filing until the rate is changed in the next base rate case.[187] The Company is proposing that, going forward, it would establish the GCR uncollectible factor in each annual GCR filing based on the most recent five-year average for net bad-debt write offs as of June 30th of each year.[188] In addition, the Company is proposing to recover gas-supply related costs through the GCR on a reconciling basis, rather than in accordance with a fixed uncollectible ratio set in the base-rate proceeding, which is the current practice.[189]

To accomplish this shift in recovery, the Company proposed to make two changes to the calculation of gas-cost related bad-debt expense in the annual GCR process. First, rather than establishing a fixed uncollectible ratio in this case for application through the next rate case, the Company is proposing to update the five-year average in each annual GCR and to use the average net bad debt write off percentage for the most recent five-year period in setting the prospective GCR rate.[190] Second, the Company is proposing to reconcile *actual* gas-cost related bad-debt writeoffs to the amount projected at the outset of the year using the rolling historical average and to recover (or return) the difference from/to customers. This methodology would not be applied to distribution-related charges. The uncollectible expense related to distribution

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187 Exh. NGRID-15, at 13.

188 Id.

189 Id.

190 Id.

rate factors would remain fixed until the next rate case, which provides the Company with a strong incentive to improve the uncollectible ratio.[191]

- *Discussion and Review of Record Evidence*

In its direct testimony, the Division argued that this annual reconciliation of gas-cost related uncollectible expense could amplify price volatility for customers, especially as a result of weather.[192] The Company does not dispute the Division's observations on the price volatility that can result from weather changes; however, at issue here is that, as currently structured, the gas-cost related uncollectible factor is effectively structured so as to penalize the Company when actual gas-cost related bad debts rise above the historical average and to reward the Company when actual gas-cost related bad debt expense falls below the historical level. For the Company, this is inconsistent with the ratemaking treatment allowed for gas-supply related costs, which are recovered on a pass-through basis because (1) the Company does not control the cost of natural gas, and (2) the Company does not earn any return or profit on the sale of natural gas. Gas-cost related bad debt is a cost that the Company necessarily and inevitably incurs in relation to the sale of gas, and like all other gas costs (also subject to price volatility because of weather), the Company should neither gain nor lose on its recovery of commodity-related costs.

It should also be noted that 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.[193] In this case, the factor calculated using the Commission's existing methodology is increasing since the last rate

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191 Tr. 9/8/08, at 121-123.

192 Exh. DIV-3, at 79.

193 Tr. 9/8/08, at 121-123.

case.[194] Adopting the Company modification to the gas-cost related bad-debt cost would ensure that the expense recovered from customers reflects actual experience and that a relatively higher ratio of bad-debt cost is recovered only when that is the Company's actual experience.

- *Proposed Statement of Findings*

Based on the foregoing, the Company recommends that the Commission make the following findings in relation to the proposed recovery of gas-cost related bad debt expense:

1. The record shows that costs related to the purchase and sale of gas commodity are recovered through the GCR on a reconciling basis.

2. The Company will incur bad-debt costs directly associated with the sale of gas commodity to customers, and therefore, gas-cost related bad-debt is a cost that is (1) eligible for recovery through the GCR, and (2) eligible for recover on a pass-through basis just as all other gas costs are.

3. The Company does not make any profit on the sale of gas commodity and should not be required to absorb gas-cost related bad-debt expense that exceeds that amount allowed for recovery through the GCR under the current methodology. Nor should the Company benefit when gas-cost related bad debt cost is less than historical levels.

4. The record shows that the Company's proposed change in methodology for calculating and recovering gas-cost related bad debt is in the public interest and is approved.

C. Pension and PBOP Reconciliation

- *Summary of Company Proposal*

The Company has proposed to reconcile pension and post-retirement benefits other than pension ("PBOP") through a DAC factor in order to facilitate funding of the Company's employee benefit plans over the long term. The reconciliation mechanism would reconcile both the annual expense and annual funding amounts to the allowed recovery in rates to ensure that customers pay no more or less than the amounts needed to adequately fund the Company's

[194] Tr. 9/8/08, at 121-122.

obligation to employees.[195] Pension and PBOP expenses are susceptible to a high degree of volatility due to circumstances beyond the Company's control such as financial market conditions.[196] The proposed reconciliation mechanism would address the volatile nature of pension and PBOP expenses and ensure that the Company's funding is maintained regardless of market circumstances beyond its control.

▪ *Discussion and Review of Record Evidence*

The Division opposes the implementation of the pension and PBOP reconciliation factor based on the claim that: (1) a reconciliation mechanism reduces the Company incentives to control costs; (2) the Company has not demonstrated that the magnitude of pension expense as compared to the overall revenue requirement is great enough to warrant reconciliation, (3) the Company has not demonstrated that the level of volatility for pension and PBOP is greater than other O&M expenses and (4) the amount of expense included in rates is calculated to provide adequate funding without the need for a reconciliation mechanism.[197] The Company does not agree with these claims for the following reasons:

First, a reconciliation mechanism will not reduce the Company incentives 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.[198] 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.[199] Specifically, on January 1, 2005, all non-union new hires were placed

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195 Exh. NGRID-3, at 46; Tr. 9/8/08, at 127-128.

196 Exh. NGRID-4, at 20-21.

197 Exh. DIV-1, at 24-28; Tr. 9/8/08, at 222-223.

198 Tr. 9/8/08, at 138-139, 249.

199 Id. at 139.

in the Valley Gas pension plan design, which had a less generous formula for its participants.[200] 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.[201] 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.[202] 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.[203] 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.[204] 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.

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200 Exh. DIV-15 (Data Request DIV-6-22).

201 Id.

202 Id.

203 Id.

204 Exh. BGRID-4, at 20.

The significance of pension and PBOP cost within the revenue requirement is highlighted by an analogous mechanism that the Commission approved for Environmental Remediation Costs ("ERC"), which is designed to recover annual costs currently in the range of $1 million annually.[205] Despite the relatively small dollar amount as compared to the revenue requirement, certainly much smaller than the pension and PBOP expense level, the Commission deemed recovery of these costs through a reconciling mechanism appropriate, with the agreement of the Division, because these costs (1) arise beyond the control of the Company, and (2) are subject to significant variation from year-to-year over time, even if not occurring at any given point in time.[206] In relation to the ERC factor, the Division has stated that:

> Although the present balance of costs subject to recovery through the ERC is comparatively small, that fact, in and of itself, is not a reason to discard this valuable mechanism for mitigating the impacts of environmental expenditures that are often unpredictable in their timing and magnitude.[207]

The same is true for pension and PBOP expenses.

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.[208] 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

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205 Exh. NGRID-4, at 22.

206 Id.

207 Exh. DIV-3, at 79-80.

208 Exh. NGRID-4, at 21.

market prices and gas prices are beyond the control of the Company.[209] 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..[210] 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.[211] 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.[212]

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209 Tr .9/8/08 at 223-224.

210 Exh. DIV-8 (Data Request DIV-1-8).

211 Exh. DIV-8 (Data Request DIV-1-9)

212 Id.

To ensure adequate funding of the pension fund and 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 PBOP funds or reserved for in order to provide customers with an equitable economic benefit.[213] 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.[214] Thus, a reconciliation mechanism will ensure that the Company funds the pension and PBOP funds at the same level as amounts collected from customers.[215] 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 years under New England Gas, and stated that this "difference …could be harmful to pension fund in the long term." 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:

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213 Exh. NGRID-4, at 23.

214 Id. at 24.

215 Id.

"[t]hat's the funding mechanism".[216] A reconciliation mechanism is the best funding mechanism to avoid an unfunded liability from growing for pension or PBOP.

- *Proposed Statement of Findings*

Based on the foregoing, the Company recommends that the Commission make the following findings in relation to the proposed pension and PBOP reconciliation mechanism:

1. The record shows that pension and PBOP costs are legitimate and unavoidable costs of operating the distribution system.

2. The record shows that pension and PBOP costs are susceptible to a high degree of volatility caused by factors outside the control of the Company.

2. The record shows that National Grid has taken steps to control its pension and PBOP costs on a going forward basis.

3. The record shows that the Company's proposed change in methodology for recovering pension and PBOP costs is in the public interest and is approved.

D. Miscellaneous DAC/GCR Items

- *Summary of Company Proposal*

In its initial filing, the Company proposed a number of tariff changes relating to DAC and GCR recovery. These items were not generally subject to extensive debate in this proceeding, although some objections were voiced by various intervenors. The list of DAC/GCR recovery items is set forth below, along with requested findings. The Company has noted where it believes intervenor concerns may apply.

1. <u>GCR: Consolidation of GCR Factors</u>. The Company proposed to consolidate its existing GCR factors into two GCR factors in order to simplify the GCR calculations and associated monthly reporting of deferred gas cost account balances.[217] This change is contested by TEC-RI.

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216 Tr. 9/8/08 at 236-237.

217 Exh. NGRID-15, at 12.

2. GCR: Natural Gas Vehicles. The Company is proposing to include a description of the Natural Gas Vehicle gas charge, which has historically been calculated as part of the Company's GCR calculation.[218] This change is not contested.

3. GCR: Gas Cost Related Uncollectible Expense. The Company is proposing to reconcile estimated gas-cost related uncollectible expense through the GCR to actual gas-related net writeoffs on an annual basis. If the recovery of gas-cost related uncollectible expense on a reconciling basis is approved, the GCR tariff will have to be modified to provide for this recovery.[219] The Company's proposal for the recovery of gas-cost related uncollectible expense is discussed in Section IV.**[?]**. The Division stated concerns in its direct testimony.

4. DAC: Establishment of RDM Factor. The Company is proposing to establish a decoupling mechanism and to recover decoupling revenues through the DAC. If decoupling is approved, the DAC tariff will have to be modified to provide for this recovery.[220] The Company's decoupling mechanism is discussed in Section V. This proposal is contested.

5. DAC: Pension and PBOP Reconciliation. The Company is proposing to establish a Pension and PBOP Reconciliation mechanism and to recover revenues associated with the mechanism through the DAC. If the pension/PBOP proposal is approved, the DAC tariff will have to be modified to provide for this recovery.[221] The Company's proposed pension and PBOP reconciliation proposal is discussed in Section II. This proposal is contested.

6. DAC: Accelerated Replacement Program: The Company is proposing to establish an Accelerated Replacement Program and to recover revenues associated with the mechanism through the DAC. If the ARP Program is approved, the DAC tariff will have to be

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218 Id. at 12-13.

219 Id. at 13.

220 Id. at 15-16.

221 Id. at 16.

modified to provide for this recovery.[222] The Company's proposed ARP Program is discussed in Section II. This proposal is not contested.

7. DAC: Recovery of DAC-Related Bad Debt: The Company is proposing to calculate its recovery of DAC-related uncollectible expense in the using the same methodology as that used for GCR revenues. If approved, the DAC tariff will have to be modified to provide for this recovery.[223] This proposal is not contested.

8. DAC: Elimination of the Weather Normalization Adjustment. If the Company's proposed decoupling mechanism is approved, the Company will eliminate the Weather Normalization Adjustment for those classes of customers subject to the decoupling prposal, which will require a modification of the existing DAC tariff. The Weather Normalization Adjustment would be retained for customer classes excluded from the decoupling proposal and for all classes if the decoupling mechanism is not adopted.[224] This proposal is not contested, pending a resolution on the decoupling proposal. Moreover, the Company has proposed to maintain the Weather Normalization Adjustment for rate classes not included in the decoupling mechanism (if approved). The Company agreed to work with the Division to develop a methodology for application of the Weather Normalization Adjustment should decoupling be approved and it become necessary to apply the adjustment to particular rate classes.[225]

9. DAC: Elimination of the Consolidation Mitigation and ERI Adjustment: The Company is proposing in this case to eliminate certain adjustments that were put in place in Docket 3401 to deal with issues arising from rate consolidation and prior rate-case settlements.

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222 Id. at 16-17.

223 Id. at 17.

224 Id. at 17-18.

225 Tr. 10/23/08, at 147-148.

These adjustments no longer apply and the Company would like to eliminate these provisions from the DAC tariff.[226] This proposal is not contested.

- *Proposed Statement of Findings*

1. The Company's proposal to consolidate its existing GCR factors into two GCR factors in order to simplify the GCR calculations and associated monthly reporting of deferred gas cost account balances is approved.

2. The Company's proposal to include a description of the Natural Gas Vehicle gas charge, which has historically been calculated as part of the Company's GCR calculation, is approved.

3. As applicable, the Company shall modify its GCR tariff to accommodate changes to the recovery of gas-cost related uncollectible expense authorized by the Commission.

4. As applicable, the Company shall modify its DAC tariff to recover or credit a decoupling rate adjustment.

5. As applicable, the Company shall modify its DAC tariff to recover or credit revenues associated with the pension and PBOP reconciliation mechanism.

6. As applicable, the Company shall modify its DAC tariff to recover or credit revenues associated with the Accelerated Replacement Program

7. The Company shall modify its DAC tariff to provide for the recovery of uncollectible expense associated with DAC revenues.

8. As applicable, the Company shall modify the Weather Normalization Adjustment.

9. The Company shall eliminate rate consolidation mitigation factor and ERI adjustment factor from Docket 3401.

10. The Company shall file revised DAC and GCR tariffs in clean and redlined form for review and approval by the Commission in accordance with the foregoing determinations.

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[226] Id. at 18.

IV. DECOUPLING

A. Overview

In this proceeding, the Company has proposed to implement a revenue decoupling mechanism to effect a fundamental change in the way that the Company recovers its approved revenue requirement. Revenue decoupling is designed to accomplish two objectives, which are: (1) to remove the strong financial disincentive that currently exists for the Company to pursue customer-level conservation opportunities in a manner that is aggressive, innovative and with full engagement of the Company's internal resources, and (2) to address the impacts of revenue deterioration resulting from persistent declines in gas usage on a per customer basis.[227]

With respect to the persistent declines in gas usage, the record shows that, from June 2004 through December 2007, the annual gas consumption of a typical National Grid residential heating customer declined by 11.4 % and for small commercial and industrial customers, the decline was 13%.[228] The record also shows that this declining usage is one of the largest motivating factors requiring the filing of this rate case. However, the Company's overriding consideration in proposing a decoupling mechanism is to break the link between sales volumes and recovery of the allowed revenue requirement, so that the Company can put its full enterprise resources to work on behalf of customers in seeking ways to reduce energy usage, and to do so without jeopardizing its recovery of allowed revenues to fund utility operations.[229]

B. Decoupling Mechanics

If approved, the decoupling mechanism would operate in the following manner: At the close of every month for each rate class included in the decoupling mechanism, the Company

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[227] Id. As of June 2008, public utility commissions in 14 states have approved decoupling mechanisms for 21 local distribution gas companies. Exh. TEC-RI-3 (Data Request TEC-RI 1-77); Exh. NGRID-13, at 36.

[228] Exh. NGRID-12, at 14-16.

[229] Tr. 10/22/08.

would calculate the actual revenue per customer in each rate class based on actual class revenues billed divided by the actual number of customers in that class for the month.. The total annual revenue surplus or shortfall for each applicable class to be credited to or collected from customers as a decoupling rate adjustment in the DAC is determined by multiplying that class revenue per customer difference by the actual number of customers in that rate class on a monthly basis. The annual decoupling rate adjustment will equal the cumulative of that calculation by class for the 12-month period ending June 30th of each year. This annual decoupling rate adjustment will be charged or credited through the DAC in the period November 1 through October 31 of each year.[230] It is important to note that the decoupling proposal in this proceeding does not effect the billed delivery rates established in this case but simply establishes a rate surcharge or credit based on this monthly revenue per customer reconciliation. The billed delivery charges will still be determined based on individual customer consumption. The decoupling rate adjustment would apply to each customer class, except for the low-income rate classes and four large C&I classes.[231] The C&I customer classes are appropriately excluded because there are relatively few customers in these classes and the customers are significantly diverse in their usage levels, which makes it difficult to apply a revenue recovery mechanism based on an "average" revenue per customer calculation.[232] In addition, the excluded classes account for a small portion of the Company's total distribution base revenues; at the Company's proposed rates, the excluded C&I classes account for 10.5 percent of total distribution

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230 Exh. NGRID-12, at 3, 9-10.

231 Tr. 9/12/08, at 5-6; Tr. 10/22/08 at 89.

232 Tr. 9/26/08, at 64.

revenues[233] and the excluded low income classes account for 5.1 percent of total distribution revenues[234].

C. Discussion and Review of Record Evidence

Both the Division and TEC-RI have expressed opposition to the Company's decoupling proposal based on similar and various arguments. However, the crux of their concern appears to center on two concepts, which are: (1) decoupling will simply work to guarantee revenues to the Company, and may allow the Company to benefit unreasonably through the addition of new customers;[235] and (2) decoupling is not needed because the Company has avoided a rate case for many years, and has options available to it to control costs and avoid the need for a rate case in the future.[236] The Company would like to address both of these assertions.

1. Decoupling Will Not Have the Effect of Guaranteeing Revenues Beyond the Revenues Examined and Approved in this Rate Case.

The record is clear that the purpose and function of the decoupling mechanism will be to provide the Company with a vehicle for recovery of the revenue requirement *approved in this case.* The Company does not dispute this point. However, it is critical to understand that the decoupling mechanism is based entirely on the average revenue required on a per-customer basis to recover the revenue requirement that will be approved in this rate proceeding.[237] The decoupling mechanism *has no effect on costs* and will not protect the Company from cost increases occurring in the normal course of business. In this proceeding, the Commission has

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233 10.5% = ($7,574,960 + $2,095,091 + $1,368,226 + $4,314,433) / $145,594,429 = $15,352,710 / $145,594,429. Attachment Rebuttal-NG-JDS-1, "Total Distribution Revenues" Large LLF, Large HLF, Extra Large LLF, Extra Large HLF.

234 5.1% = ($464,046 + $7,005,583) / $145,594,429 = $7,469,629 / $145,594,429. Attachment Rebuttal-NG-JDS-1, "Total Distribution Revenues" Non-Heat Discount, Heat Discount.

235 Exh. DIV-3, at 4; Exh. TEC-RI-1 at 18.

236 Exh. DIV-3, at 7-9; Exh. TEC-RI, at 34.

237 Exh. TEC-RI-3 (Data Request TEC-RI 1-49).

reviewed the Company's actual costs for a single year, the test-year period ending September 30, 2007, as adjusted through the rate year period, and those costs will serve as the basis for the establishment of the revenue requirement and targeted revenue per customer. However, the Company's actual operating costs will inevitably differ from the amounts built into rates. Following the rate case, the Company will be able to reduce some costs through cost-control initiatives, but there will be other costs that increase as a result of various factors both within and without the Company's control. This is always the case. The point is that cost changes *are not reflected* or captured by the decoupling mechanism. The decoupling mechanism is consistently applied on the basis of the revenues per customer established in this rate case, and if the Company's costs increase, the revenue the Company receives through the mechanism will not inherently or automatically address the Company's revenue deficiency. The Company will need to come to the Commission for authorization of an increase in the revenue requirement if costs exceed the revenue requirement approved in this proceeding.[238]

The corollary proposition relating to the "guarantee" of revenues is that the decoupling mechanism will eliminate Company's incentive to reduce costs.[239] However, the incentive to reduce costs is no different with decoupling than without decoupling for the very reason mentioned above: the decoupling mechanism operates to recover the revenue requirement approved in the Company's most recent rate case, which does not include amounts related to cost increases occurring since the rate case. Therefore, if the thought is that, under the current ratemaking paradigm, the Company has a strong incentive to manage costs between rate cases, then it should be understood that decoupling *does nothing* to change this. The decoupling mechanism does not recover cost increases; therefore, if the Company wants to earn its return, it

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238 Tr. 9/26/08, at 214-216.

239 Tr. 9/26/08, at 228.

must manage costs in the same exact manner as it would without decoupling because cost increases will depress the Company's earned return (with or without decoupling), unless the Company is able to mitigate those costs.

It is telling that, despite strenuous opposition from the Division on decoupling, the Division's witness had to acknowledge that decoupling does not eliminate the risk of inflation, which means that decoupling will not address increased costs that the Company will incur in all areas of its operation, which are highly sensitive to inflation, such as labor, construction materials, fuel costs and similar types of costs.[240] Thus, rather than providing support for the claim that decoupling will eliminate cost control incentives, the record shows that the Company has a strong track record of controlling operating expenses to mitigate inflationary pressures while paying its workforce competitive wages.[241] For example, the Company is installing automated meter reading technology in Rhode Island, which lowers customer-service costs because the need for meter readers is reduced.[242] There is nothing about decoupling that will change the Company's motivation to achieve cost reductions through investments in technology because decoupling will never provide the Company with any more revenues than approved in the last rate case, except in terms of providing the approved average revenue level for new customers. On the other hand, cost reductions would help the Company to increase its earnings, which is an incentive that is unchanged by the introduction of decoupling because decoupling attempts to stabilize the Company's *revenues* in the face of declining usage, but does not necessarily work to provide the Company with *earnings*.

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240 Exh. DIV-5, at 38; Exh. TEC-RI-2, at 22

241 Tr. 10/22/08, at 122.

242 Tr. 10/22/08, at 123-124.

As to the issue of customer growth, both the Division and TEC-RI have implied that decoupling guarantees the Company's revenues, while also allowing the Company to increase its revenues through customer growth, and that this may be an unfavorable result. However, there are three important points to consider in relation to growth and the decoupling mechanism. First, as an initial matter, it should be noted that, if decoupling is not approved, the Company would be entitled to retain any growth-related revenues actually billed until the next rate case under the traditional ratemaking structure (putting aside operation of the annual earnings sharing mechanism). As it relates to incremental revenues from added customers, the decoupling mechanism limits the revenues that the Company is allowed to retain to an amount equal to the class average revenue per customer as a result of the decoupling rate adjustment calculation. Consequently, if added customers are billed, based on consumption, an amount greater than the class average revenue per customer, a decoupling rate credit would be produced and the opposite effect would occur if the added customer was billed, based on consumption, an amount less than the class average revenue per customer..[243] Second, the addition of new customers will not necessarily "guarantee" additional revenues, above those that would have been realized under a properly functioning regulatory framework, to offset growing costs because the Company will incur costs associated with adding new customers.[244] Third, if and when the addition of new customers has the effect of adding revenues in excess of costs, customers would get a share of these earnings through the earning sharing mechanism.[245] With or without a decoupling mechanism, customer additions will benefit existing customers.

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243 Tr. 9/26/08, at 220, 234.

244 Tr. 9/26/08, at 208.

245 Tr. 9/26/08, at 228; RR-COMM-24.

The Commission has recognized the need to depart from a traditional ratesetting approach for water utilities in order to break the link between sales volumes and the recovery of an *allowed* revenue requirement for water utilities by increasing operating reserves to mitigate the effect of declining consumption on a Company's revenue recovery efforts. Providence Water Company, Docket No. 3832, Order No. 19145 (2007); Newport Water Company, Docket No. 3818, Order No. 19240 (2008). Simply put, the Company's has proposed to implement a decoupling mechanism because traditional ratemaking does not allow the Company a reasonable opportunity to cover the costs of doing business during periods that customer use is declining, for example in response to price increases or as a result of energy efficiency programs[246]. The proposed decoupling mechanism is an approach that produces results that are similar to the conditions that existed in earlier periods when traditional ratemaking provided gas utilities with reasonable opportunities to earn a fair rate of return.

In this case, the Company is asking the Commission to recognize that there is no fundamental reason that rates must be set by dividing the allowed level of revenues over a level of sales volumes that is *fixed* for the duration at a certain point in time, which is what the current ratesetting process does. Approval of the decoupling mechanism will simply provide the Company with the revenues approved in this docket, as recovered from the customers that exist on the system from year to year. . It will neither guarantee the recovery of costs increases, nor provide the Company with the promise of incremental earnings. In any event, the annual application of the earnings sharing mechanism will ensure that the Commission has the opportunity on an annual basis to review the Company's financial position and to provide customers with their share of any earnings that arise.

[246] Tr. 9-12-08 at 53 – 57, 134.

2. The Argument that Decoupling is Not Needed Because of Past History is Not Accurate.

The Division and TEC-RI have testified that the Company has operated its business for many years without the need for annual decoupling adjustment, and therefore, there is no compelling reason to implement the mechanism now. As an initial matter, this assertion sidesteps the Company's main intention with decoupling, which is not to maintain earnings, but rather to break the link between sales and recovery of the approved revenue requirement so that the Company is empowered to pursue energy conservation as a business matter.

As proof of its claim that decoupling is not needed, the Division argues that the Company is recovering $600,000 more in distribution revenue since its last rate case. Yet, an increase of $600,000 in distribution revenues over a six-year period constitutes an increase in distribution revenues of 0.5 percent, which does not even begin to equal the increase in costs due to inflation, and because of the addition of new customers in the meantime, actually highlights the Company's concerns in this case.[247] In fact, the record shows that, despite a significant decline in revenues (and revenue per customer), the Company did not file a rate case because (1) a rate freeze was in effect through 2005; (2) when the rate freeze expired, Southern Union was actively seeking to sell the Company, rather than invest in its future,[248] and (3) it took some time following National Grid's acquisition for the Company to put itself in a position to make a filing, which was acknowledged by the Division's witness.[249] These circumstances were unique and were clouded by the fact that Southern Union was not invested in its Rhode Island operations, which is not the case with National Grid. Thus, the fact that, in past experience, the Company

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247 Exh. NGRID-13 at 26.

248 Tr. 9/12/08, at 91-2.

249 Tr. 10/21/08, at 205.

avoided the need for a rate case for several years is not in any way indicative of going-forward reality.

However, even if ROE is an indicator of the need for a decoupling mechanism, the record shows that the Company has not achieved its authorized ROE since fiscal year 2005.[250] In terms of declining usage, the record shows that, although gas usage has been declining since 1980, the rate has accelerated since 2000, reaching 4.9 percent from 2004 through 2006, with a critical break experienced in 2005 with the unprecedented price spikes resulting from Hurricanes Katrina and Rita.[251] This experience demonstrated clearly that, in response to recent prices increases, there has been increased conservation, which is a point that is conceded by TEC-RI in this case: high prices are driving consumers to use less energy.[252] Significantly, the record shows that, even if the decoupling proposal made by the Company in this docket had been in place since the last rate case, the Company still would not have made its authorized ROE of 11.25 % from 2005 though 2008.[253] This is because decoupling does not guarantee the Company's earnings.[254]

3. Other Concerns Raised by Intervenors

There are a number of other concerns with decoupling that were raised by the intervenors. These issues include the following:

First, the Division testified that there are other alternatives to decoupling such as weather normalization or higher fixed charges. However, the Division's witness conceded that weather normalization, higher fixed charges, and declining block rates do not eliminate sensitivity of the

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250 Tr. 9/29/08, at 67-68; See, New England Gas Company, Order No. 18838, Docket No. 3760 (2007), National Grid, Order No. 19152, Docket No. 3859 (2008).

251 Exh. NGRID-12 at 29; Tr. 9/12/08, at 164-165.

252 Tr. 9/26/08 at120; Exh. TEC-RI-1, at 22.

253 RR-DIV-5.

254 Tr. 9/29/08 at 165.

Company to reduced revenues due to conservation,[255] 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.[256] Moreover, weather normalization does not protect against conservation, it simply operates to eliminate weather-related volatility from *average* from period to period. Over time, the cumulative weather normalization adjustments should approach zero as cumulative period to period weather approaches *average*[257] Also, a rate-design structure with higher fixed charges reduces the price signal to consumers to conserve.[258] 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 Division testified that decoupling is unnecessary because conservation can occur without the utility's involvement and that National Grid is mandated to promote energy efficiency. However, 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.[259] The record also shows that disincentives have a significant influence on utility policies and that utilities are key players in promoting conservation.[260] 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

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255 Tr. 10/23/08 at 180.

256 Tr. 10/22/08 at 99.

257 Exh. NGRID-13, at 31; Tr. 10/22/08 at 47.

258 Tr. 9/26/08 at 172; Tr. 10/23/08 at 73.

259 Tr. 9/29/08 at 164-165; Exh. TEC-RI-1, at 19.

260 Tr. 10/23/08 at 68, 73-74.

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.[261] 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.[262]

Third, the Division and TEC-RI both expressed concern regarding the possibility of large increases due to operation of the decoupling mechanism. Under traditional ratemaking, there are fewer, but larger rate increases, while decoupling increases occur on an annual basis to a lesser amount.[263] 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.[264] 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.[265] Thus, the concern regarding large annual increases is unfounded.

Fourth, TEC-RI argued that decoupling will reduce customer incentive to conserve; however the Company does not agree with this assertion. 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.[266] 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

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261 Tr. 10/22/08 at 28.

262 Id. at 32.

263 Tr. 9/26/08 at 177.

264 Tr. 9/29/08 at 92, 94-5.

265 Exh. TEC-RI-3 (Data Request TEC-RI 1-7).

266 Tr. 9/26/08 at 121-23.

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.[267] 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.

As explained above, the Company is advocating for the implementation of decoupling because it firmly believes that a change in the ratemaking paradigm will put the Company in the position of being a full and active supporter of conservation efforts for all customers on the system. This benefits customers and the environment. Although many issues were raised in relation to the decoupling proposal, the simple ramification of its implementation is that revenue recovery will be accomplished in a slightly different manner than it currently is today, with smaller annual changes replacing larger periodic increases. If approved, the Commission will retain full control and oversight over the Company's operations and will have an opportunity each year through the earnings sharing mechanism to ensure that the mechanism is working as expected and is not harming customers. Accordingly, the Company requests that the Commission approve its decoupling request.

D. Impact on Return on Equity

In this proceeding, the Division has argued that the Company's allowed ROE should be reduced by 75 basis points if decoupling is adopted. However, there is no record basis for this adjustment, which makes it clear that this claim must be rejected. The reasons for this conclusion are as follows:

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[267] Exh. NGRID-13, at 18-19.

First, the Division's witness could not justify his recommendation to any extent. As an initial matter, the Division's witness testified that his 75 point basis reduction related to the inclusion of the industrial customers in the decoupling mechanism, but he could not quantify what the impact was or what the adjustment would be without those customers included. In fact, he suggested it would take an "almost infinite amount of work" for him to figure it out. Specifically, the witness testified:[268]

> Q. And you said that that's -- that there would be a 75 basis point reduction for adoption of decoupling?
>
> A. Yes. If it's adopted in the way -- in the way that my understanding of what the company is asking for which would include residential, commercial and current industrial customers.
>
> Q. Well, is there a way that decoupling could be adopted where you wouldn't adjust the ROE?
>
> A. Where I wouldn't adjust the ROE. If industrial customers were not included, the reduction would be less, it still wouldn't be zero, I haven't tried to separate it, that's a much harder task to do because the lion's share of the reduction in non-diversifiable risk occurs with the industrial customers because that's the group that swings the most with changes in the economy. So I don't have a ready answer for what you're saying. I would have to look at that variation of risk distribution between the customer classes.
>
> Q. So if the industrial class was excluded from the decoupling mechanism, you wouldn't be recommending that kind of a reduction in the ROE?
>
> A. It would be less than 75 basis points, but as I said to you, I haven't done the work. I don't know how much less.
>
> Q. Do you realize that one of the parties in this case is recommending that decoupling be done that way?
>
> A. I didn't specifically know that, but that doesn't surprise me.
>
> Q. So your testimony is that if it's adopted without the commercial/industrial class, some portion -- or some portion of that class, then your 75 basis point reduction would not be applicable?
>
> A. My testimony is -- I didn't say anything about commercial. I said if the industrial class was not included in toto, then the reduction I would recommend would be less than the 75 basis points, but I don't know right now how much less because I have not done that work.

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[268] Tr. 9/11/08, at 44-45.

Q. What would the Commission do in trying to figure it out if, in fact, decoupling was adopted with the industrial class excluded?

A. Well, I guess if the Commission were leaning that way, it could ask me to do the work, and if the company wanted to cooperate and give me the data I needed, we could do that work.

Q. You don't have any evidence to put in the record today, though, on a different way of reducing the ROE if the industrial class is excluded from the decoupling mechanism, is that correct?

A. That's correct. Of all the many different scenarios we can talk about today that rates could be made in and various rate designs, et cetera, et cetera, I haven't looked at all of them. And if for no other reason than doing that would ask for a -- would require requesting the Commission have an extraordinarily long extension of the time to do these proceedings. You're asking me to do what's almost an infinite amount of work.

Thus, despite being the determining factor in his analysis, the Division's witness could not provide any evidence on how much of the 75-basis point reduction related to the inclusion of C&I customers, nor how much the adjustment would be decreased by the exclusion of these classes from the decoupling mechanism. Since this testimony, the Company has excluded those customers because the "average revenue per customer" approach is unlikely to function properly in classes with a diverse customer profile. As a result, there is no support in the record for an ROE adjustment of any level relating to the implementation of the decoupling mechanism.

Moreover, this testimony underscores the fact that the Division's witness provided no empirical analysis of his recommended adjustment, which concluded that the implementation of a decoupling mechanism would render the cost of the Company's common equity essentially equivalent to the cost of highly rated corporate debt.[269] In fact, the Division's witness provided no analyses, either qualitative or quantitative, to support his assertion that the cost of equity falls when decoupling mechanisms are implemented. Rather, Mr. Rothschild simply assumed the outcome that the cost of equity would fall; then further assumed that the effect of decoupling is

[269] Exh. DIV-5; Exh. NGRID-12, at 5.

so substantial that equity investors would face no more risk than investors in highly-rated securitized debt.[270] In addition, the Division's witness provided no analysis or insight into the way in which he has related the AA-rated corporate debt rate, which at the time was 4.89 percent, into a 75 basis point reduction in ROE.[271] Similarly the Division's witness provided no analysis or calculation quantifying the effect, if any, of decoupling on the cost of equity.[272]

Third, the record shows that the Company's witness on the effect of decoupling on ROE tested Mr. Rothschild's premise using several quantitative approaches and found no evidence to support Mr. Rothschild's assumptions or conclusions. The record further shows that the results of those analyses showing that no adjustment is warranted are consistent with positions taken by both Moody's and Standard and Poor's, neither of which have ever increased a company's credit rating as the result of decoupling.[273] In fact, if Mr. Rothschild is correct and a 75 basis point adjustment is appropriate, then companies with decoupling mechanisms would have their ratings increased by six ratings "notches"; yet as noted above, there has never been an instance in which a utility's has been increased by even one ratings notch.

The record also shows that the Division's witness' own data does not support his position. The Company's witness used Mr. Rothschild's data and assumptions to determine the beta coefficient that would have to exist in order for Mr. Rothschild's 75-basis point reduction to work in the context of his capital asset pricing model.[274] The Company's witness determined that, for Mr. Rothschild's recommendation to work, the beta value in the CAPM would have to

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270 Exh DIV-5 at 40 NOTE: I ASSUME THAT EXH. DIV-5 IS ROTHSCHILD'S DIRECT

271 Exh. NGRID-12, at 5.

272 Id. at 6.

273 Exh. NGRID-12, at 28.

274 Tr. 9/11/08, at 46-48.

well below the beta coefficient of any of Mr. Rothschild's proxy companies, with "beta" representing the measure of volatility of the Company's stock.[275]

Fourth, putting all else aside, the record is clear that the Division's witness failed to perform any research or analysis of decoupling mechanisms or how they operate. When asked, the witness could not describe how the decoupling mechanism works or how it has been applied in other jurisdictions.[276] In fact, the record shows that the overwhelming majority of commissions have rejected recommendations to lower ROEs after implementing decoupling. Of the 33 proceedings where decoupling has been implemented, 26 resulted in no change to ROE. In the seven proceedings that did result in a change, five of the cases involved a reduction of 10 basis points and, in two cases both within the state of Maryland, there was a 50 basis point reduction.[277] Thus, the Division's expert could not point to any jurisdiction that reduced a ROE by 75 basis points due to decoupling, nor any broad support for an adjustment of anything more than a very small amount.[278]

Fifth, the Company's witness made it clear that decoupling is needed to bring National Grid on par with other regulated gas companies, and that without decoupling, it will actually have a higher risk profile because the proxy group companies already have revenue stabilization mechanisms in place. In that regard, the ROE computed for National Grid is based on a proxy group of companies with local gas distribution business. All of the companies in Mr. Moul's proxy group have some form of revenue decoupling in place for a significant portion of their operations.[279] The Company testified that, if decoupling was so beneficial to a utility, there

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275 Id. at 149; RR-COMM-18.

276 Tr. 9/11/08, at 48.

277 Exh. NGRID-12 at 25-26, Tr. 9/10/08 at 139-140.

278 Tr. 9/11/08 at 46-7.

279 Exh. NGRID-18, at 11.

would be a change in debt ratings for companies having implemented decoupling and this has not occurred because decoupling "stabilizes an otherwise deteriorating effect" from declining gas usage per customer.[280] In fact, Moody's has indicated that companies without decoupling stand a greater risk of downgrade.[281] Even the Division's witness admitted that "if the lower future cash flows were from …declining use per customer…if there's less and less and less money to service debt, there's more and more pressure on a bond rating."[282] The Company further testified that the financial community will view the adoption of a decoupling mechanism as signal that the Company's regulators are focused on the financial stability of the companies they regulate.[283]

Lastly, it should be noted that the Division's witness testified that a *45 basis point* adjustment to ROE is "certainly very significant" and is a "big deal" in terms of the signal that it sends to investors.[284] On this point the Division's witness also testified that:[285]

> Q. Well, if 45 basis points is a big deal to investors and there's not one jurisdiction in the United States of America who has done a reduction of 75 basis points for decoupling, wouldn't it be a huge deal to investors, if suddenly the ROE was adjusted by 75 basis points because decoupling was employed?
>
> A. Well, I think you are leaving out a huge factor here and that is the inclusion of the industrial customers.
>
> Q. It was a yes or no question. Was the answer no or yes?
>
> A. Gee, I don't know -- I wish I could just simply say yes or no. Your question talked about no other jurisdictions doing something without pointing out that most of those, if not -- and possibly none of those jurisdictions, I'm not sure, but at least the ones that we've seen in this proceeding have not implemented the decoupling for industrial customers, and that's the major part of the action.

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280 Tr. 9/10/08 at 134, 141-142.

281 Exh. NGRID-18, at 14.

282 Tr. 9/11/08 at 38.

283 Tr. 10/22/08, at 17.

284 Tr. 9/10/08, at 227.

285 Tr. 9/11/08, at 54.

Accordingly, there is simply no basis in the record for the Commission to conclude that an ROE adjustment should apply, and even if so, what the quantification of that adjustment should be. The Commission would be left to guess and nothing more.

E. Proposed Statement of Findings

Based on the foregoing, the Company recommends that the Commission make the following findings in relation to the proposed decoupling mechanism:

1. Decoupling is a mechanism designed to allow the Company to recover the revenue requirement approved in this proceeding.

2. It is in the public interest to break the link between sales volumes and revenue recovery for the gas company. The implementation of a new approach to the recovery of the allowed revenue requirement will enable the Company to take all reasonable business efforts to promote conservation by customers, which will benefit customers in the form of reduced bills and will benefit the environment in the form of reduced energy consumption.

3. There is no basis for a reduction in ROE in relation to the implementation of decoupling. The record evidence neither supports, nor requires such a result because the members of the proxy group upon which the ROE analysis relies have decoupling mechanisms in place, and no evidence has been developed showing a legitimate basis for quantifying any change in the cost of common equity arising from the implementation of decoupling.

4. The Company shall be authorized to implement a decoupling mechanism to be calculated on a monthly basis and reconciled on an annual basis.

V: NON-FIRM RATES

A. Overview

In this proceeding, the Company has proposed to establish a cap on the price that dual-fuel customers would pay for non-firm distribution service and to make a number of other changes in the terms and conditions of non-firm service.[286] Under the Company's existing rate tariffs, non-firm service is available only to customers who have dual-fuel capability and the non-firm price is derived by applying a discount to the cost of the customer's alternative fuel (generally, No. 2 or No. 6 heating oil).[287] Fundamentally, this "value of service" ("VOS") pricing system is designed to promote gas usage during times when oil prices are lower than natural gas, and to obtain the "value" of distribution capacity during periods when alternative fuel sources are higher than natural gas. Because oil prices recently have been much higher than natural gas, the issue has arisen as to whether excess distribution capacity should have a value other than some measure of the "cost to serve" non-firm customers. For the reasons discussed below, the Company strongly believes that the Commission should not change the current non-firm pricing system beyond the Company's proposals in this case. This is because the allocation of fixed system costs to a migrant class of customers, and the establishment of non-firm "cost-based rates" for customers who have made no commitment to the system, will not serve or protect the interests of firm customers, especially residential and smaller commercial customers *who do not have any choice* but to take service as firm customers.

In Rhode Island, the VOS pricing framework has functioned without problem for over 20 years, encompassing a long period where the prices for natural gas and heating oil have been closely correlated. Although many characterizations to the contrary exist on the record, non-firm

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286 Exh. NGRID-15, at 18-19.

287 Id. at 19.

customers are large, dual-fuel C&I customers that actively participate in the energy marketplace and that are entirely *free* to make rational economic decisions to burn oil when it is to their economic benefit (i.e., when the price is relatively low or is lower than natural gas), which they have done for the past 20 years. However, because circumstances arose where heating oil prices became relatively high and volatile in comparison to natural gas, the Company's non-firm customers have become extremely dissatisfied with the VOS pricing structure and are seeking a change that will reduce their prices.

In rendering a decision in this proceeding on possible changes to the pricing for non-firm service, the Commission should not overlook the fact that the Company's least-able-to-pay residential customers are as adverse to increases in energy costs as the large C&I customers who take non-firm service from the Company. In other words, nobody likes a rate increase in their energy bill, and the movement to establish a "cost-based" non-firm rate is based on a desire to avoid as much energy cost as possible. This is economically rational behavior for companies who must compete in the global marketplace, and certainly, large C&I customers are employers in Rhode Island, which should be a significant consideration in this proceeding. The Company recognizes this fact and, in addition, is working to motivate as much use of the distribution system as possible; hence, the agreement to cap the VOS pricing. However, the non-firm customers status as economically important entities should not cloud the Commission's judgment on the need to establish a pricing structure for non-firm service that is fair *for all customers* and that recognizes that, while they are *not committed* to the system as firm customers, they rely on its availability in times when oil prices are relatively high or other factors require them to burn gas.

The Company's problem is that the change that the non-firm advocates are seeking would reduce their costs to a level that far exceeds the need to address the alleged "inequity" of the VOS system, and that would create a special discounted rate for a group of customers that, by their own admission, are highly unlikely to burn oil on their own motion when its price greatly exceeds that of natural gas. So long as oil prices are high relative to natural gas, non-firm customers should not be afforded rate treatment that is preferential to firm service customers, i.e., if the cost of their alternative fuel is so high as to be "uncompetitive" with natural gas, then these customers should be encouraged to become firm service customers and to share in the costs of the system *that they are using to meet their energy needs*. If they do not want to commit to the system as firm customers, then they can maintain their non-firm status and pay a price (VOS subject to a 150% rate cap), which provides a (significant) discount to their alternative fuel, but allows the Company to collect revenues that will offset the cost of the system for firm customers. When and if oil prices fall, the Company should have the flexibility to reduce the price of non-firm gas service to lower levels accordingly in order to attract and maintain utilization of the system. This philosophy is the basis of the Company's proposal in this proceeding, which is a VOS pricing mechanism subject to a price cap that triggers when the differential between oil and natural gas is relatively great.

As discussed below, significant debate in this proceeding has focused on the identification of a "cost-based rate" for non-firm service. The Company recognizes that, in the ratesetting context, the concept of a setting a "cost-based" rate has natural appeal where the existing VOS system may appear "usurious" or unreasonable even when a cap is applied. However, there is a substantial issue in fairly and reasonably determining the "cost to serve" non-firm customers, which is the reason that there is confusion in this docket over the

Company's development (or alleged lack thereof) of a cost-of-service based rate for non-firm service. In fact, for the reasons discussed below, the Company's proposal represents the resolution that best meets the Commission's public interest considerations and that best serves the interests of the Company's firm customers, while extending a substantial level of rate relief to non-firm customers. Accordingly, the Commission should approve the Company's recommended approach for non-firm pricing.

B. Company Proposal

The Company's existing non-firm tariff rate establishes the non-firm rate on a monthly basis, priced so that the sum of the cost of natural gas and National Grid's distribution rate provides the customer with a discount off the cost of the customer's alternative fuel. The level of discount is based on the amount of gas that a customer can use and the type of alternative fuel, with discounts currently ranging from 2.25 percent to 22 percent. The distribution rate in this calculation is also subject to a floor price (generally $0.10 per dekatherm in the summer and $0.16 per dekatherm in the winter), but there is no cap or maximum charge. Revenues generated through non-firm service are funneled back to firm service customers to offset their distribution costs. Specifically, the Commission has designed base rates to include a credit of $1.6 million, which represents the baseline level of non-firm revenues expected to occur for the benefit of firm customers. Revenues obtained over and above the $1.6 million threshold are shared between customers and the Company on a 75/25 basis, respectively. The record shows that, over the past three years, the total offset provided to firm service customers has ranged from $3.0 to $4.5 million, including the $1.6 million amount currently included in base rates.

In this case, the Company is proposing to retain and modify this structure as follows:

1. The proposed revenue requirement contains a line-item credit of $1.6 million, which reduces the cost of service for firm service customers because it reduces the amount of the revenue requirement to be recovered over firm billing units.

2. The VOS distribution price calculated for any non-firm customer would be capped at 150% of the firm distribution rate. This does not mean that the customer consistently *pays a rate* that is 150% of the comparable distribution rate. The customer would pay less if the differential between natural gas and the customer's alternative fuel is less, which has occurred frequently.

3. The Company proposed to reintroduce "Flexible Firm Service," which allows the Company to work with non-firm customers to negotiate an individual service agreement, which can include a fixed-price for a defined service period. Flexible Firm service would be available to customers using greater than 150,000 therms per year. Individual service agreements would be subject to Commission approval[288]

4. The Company proposed to eliminate non-firm sales service because competitive options for non-firm gas supply are readily available in the marketplace and the service creates unnecessary administrative burden.[289]

5. The Company proposed to change the timeline for providing a distribution rate quote for the upcoming month 10 business days in advance to the 1st of the next month. The current rules require 5-day notice.[290]

B. Company Concerns with a "Cost-Based" Rate

As noted above, considerable debate has arisen in this docket over the development of a cost-based rate to serve as the basis for a new non-firm rate. The Company does not support the creation of a cost-based rate for the following reasons:

First, a "cost-based" rate is typically set based on a cost of service study that is conducted to identify and quantify the costs to serve a particular customer class. This requires the allocation of costs incurred to meet the needs of all firm customers at peak periods. However, building and maintaining the system to meet the peak needs of the firm customers creates capacity that can be used by other customers, i.e. non-firm, at times other than peak. The

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288 Id. at 21.

289 Id. at 20-21.

290 Id. at 22.

problem that arises in conducting a cost of service study for non-firm customers is that there is an inherent conflict in allocating costs incurred to provide service to customers at peak to customers who by definition, are not served during peak periods. Allocating all of the system costs to firm customers would indicate that the system is fully paid for when the Company extends non-firm service to customers and the *actual* cost incurred by the Company to serve a non-firm customer is, in reality, limited to the Company's incremental or marginal cost, which includes little more than certain variable administrative costs.[291] The Company agrees with the testimony of SilentSherpa on this one point.

The Company strongly disagrees with the SilentSherpa on his next point, which is that the marginal cost should serve as the sole basis for the establishment of a "cost-based" rate. The marginal cost does not include the cost of constructing, maintaining and operating distribution system assets, yet the non-firm customer is certainly using those assets to receive service. The first standard of utility rate design is that rates should be just and reasonable[292]. No possible interpretation of that standard would allow the setting of a non-firm rate by excluding these costs. Therefore, a legitimate non-firm rate cannot be designed to omit *any* costs associated with the facilities that stand ready for use at the discretion of the non-firm customer. Thus, the marginal cost represents a "floor" or the least possible price that a non-firm customer should be paying under any circumstances.

In that regard, the record in this proceeding includes the decision of the Massachusetts Department of Public Utilities in D.P.U. 93-141-A (1996), wherein the Department adopted a VOS pricing model that allows gas companies to negotiate individual service agreements that must be demonstrated to *exceed* the marginal cost price. The gas companies negotiate with

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[291] Testimony of SilentSherpa.

[292] Exh. NGRID-14 (Direct Testimony of D. Heintz) at 16.

individual customers based on the market pricing that the customer would pay for its alternative fuel. The agreements can be multi-year agreements and require the Department's approval under certain circumstances (but not all circumstances).[293] From the Company's perspective, the Massachusetts model would not be acceptable here because Rhode Island has historically favored the provision of non-firm service through tariffed rates rather than allowing broad-based negotiation between the Company and non-firm customers; hence, the marginal cost study would not be useful or necessary in this context.

The alternative to a marginal cost study is an embedded cost study, which involves the allocation of costs associated with building, maintaining and operating the distribution system to the non-firm rate class.[294] Although the Company has produced at least two iterations of an embedded cost study in this proceeding,[295] the Company does not agree with the use of an embedded cost study to set rates for non-firm customers. As an initial matter, the fundamental premise of an embedded cost study is to determine cost responsibility for customers *who are committed to the system* and require the facilities to be available for their use in given time periods. Thus, the allocation of costs through an embedded cost study to non-firm customers is an inherently arbitrary task that necessitates a slew of judgments and assumptions on the assignment of costs, although those costs are not incurred by the system to serve the customers for whom the cost study is being performed. The arbitrariness of this task is underscored in this proceeding by the fact that two different cost studies produced two different results, with the

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293 Exh. RIH-2.

294 Transcript

295 See, Exh. DIV-13 (Data Request DIV-5-53); Exh. NGRID-38; Exh. NGRID-38(Revised); Exh. NGRID-39; Exh. NGRID-39(Revised).

difference simply being the level of distribution costs assigned to the non-firm class, and the resulting level of discount from firm rates that is produced.[296]

In addition, a critical concern for the Company arises in relation to the proposition that a rate class would be established for the non-firm customer base, with costs identified through the cost study actually assigned to that rate class. This possibility creates two significant concerns for the Company: (1) the assignment of distribution costs to an interruptible rate class will skew the rate design for other (firm) customer classes because it will take costs away from firm classes in an arbitrary and artificial manner with the resulting rates not reasonably representing the costs of serving firm customers in the affected rate classes, and (2) non-firm customers are not required to make any commitment to take non-firm service over a period of time in order to ensure that the costs allocated to the non-firm class will be recovered.

Even if the idea is to simply identify a "cost-based rate," but not to actually establish a new rate class designation or to assign costs to that rate class, the concept is flawed. By definition, a rate that is based on the allocation of embedded costs to non-firm customers must constitute a discount to firm distribution rates (because non-firm customers are not necessarily served on peak). The Company is fundamentally opposed to a non-firm rate that is structured as a fixed discount to firm service because (1) it will serve only to create incentives to avoid firm service where firm service would otherwise be desirable and cost-effective for the customer, and (2) it does not provide the opportunity for the Company to adjust its non-firm rate *downward* in the event that oil prices fall below natural gas and it would be in the interests of firm customers to make the capacity available at a lesser cost than oil.

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[296] Id. The primary allocation factor used to allocate distribution system demand costs is the RSUM (Relative System Utilization Method). The contribution of each class to this factor is determined by the level of its monthly volumes relative to total system volumes. Thus, changes in volume levels and timing (i.e. month of use) of that volume can impact the amount of costs allocated to the class.

In that regard, if it is more economical for the non-firm customer to take firm service than to take non-firm service or to use its alternative fuel – then the customer should be taking firm service. Non-firm service is not designed or intended simply to provide large, dual-fuel customers with a more economical option than firm service and the Commission should not establish a fixed, cost-based price for the sole purpose of creating that economic advantage. Non-firm service is intended to *attract* usage of the system where the customer is in a position to avoid using natural gas through the use of an alternative fuel source and would otherwise do so if the economics allow. If the customer is not willing or able to avoid using natural gas because the economics of the situation are not advantageous to the customer, then the customer should be taking firm service and sharing the costs of the system with smaller, firm customers.

The record shows that this concern is highlighted by the fact that the Company has experienced a significant level of migration from non-firm to firm service by large C&I customers in the past year. This migration has occurred because the firm service rate is more economic for the customer than the customer's alternative fuel. If the Commission were to establish a fixed, "cost-based" rate in this proceeding, the Company's expectation (and that of other parties) is that these customers would re-migrate to non-firm service at the earliest opportunity. To the Company, this is simply poor ratemaking policy since the rate established by the Commission will have had the effect of encouraging *less* use of the system.[297]

Although other parties in this proceeding may not agree, the Company believes that its proposal to maintain VOS pricing subject to a cap at 150% of the comparable firm rate best meets the Commission's public policy goals, as well as its directive to propose a "cost-based rate

[297] The argument was made in this case that a lower price will motivate greater throughput, which would make up for any loss in revenues resulting from the implementation of a lower rate rather than a higher rate, but there is no record evidence supporting this supposition.

design" for non-firm service in this proceeding.[298] The Company's position is that, when the customer's price of using an alternative fuel is so much higher than the cost of natural gas (as contended in this proceeding) that it renders oil "non-competitive" with natural gas, then the economical choice for the customer is to take firm gas service from the Company. In that case, it is not necessary or appropriate for the Company to provide a discount to firm service because the Company would only do so *if it would otherwise lose the throughput*. If there is no chance that the Company would lose the throughput, then there is no basis for the Company to offer a rate other than the firm service rate; this is the fundamental premise of the requirement that a non-firm customer have dual-fuel capability. If the customer wants to leave its options open, rather than taking firm service, then the customer should be paying a rate that provides a discount to the alternative fuel, but that also maintains the incentive for the customer to take firm service. By definition, this would be a price that would *exceed firm service* and that would be derived using the VOS methodology. In this case, the Company proposed to cap that price at 150% of the comparable firm rate on the theory that the firm rate represented the "cost-based rate" for that customer, and therefore, a device that capped the customer's VOS price at a multiple of the firm rate would not only reduce energy costs for that customer, but would also be rationally related to the costs of serving that customer as a firm customer. This approach recognizes that the Company's business is to generate utilization of the system and therefore pricing signals should be designed to motivate use of the system whether the price of oil is higher or lower than natural gas at any given time. This approach also recognizes that, although VOS pricing could result in a price that is higher than the firm distribution rate, it will always provide a discount to the customer in comparison to the customer's alternative fuel (except in the unusual circumstance

[298] Exh. SilentSherpa-8.

when the non-firm floor price is in effect) and it will generate a price that is lower than the firm distribution rate when the differential between oil and gas is smaller.

As a result, the Company's proposed methodology stands as the best alternative suggested in this proceeding for meeting the important ratemaking goals involved in the non-firm issue, which are (1) to motivate throughput regardless of the relative magnitude of the price differential between oil and natural gas, (2) to ensure that customers receive a benefit to offset their costs of supporting the system when throughput occurs, (3) to ensure that non-firm pricing is structured in a fair and reasonable manner given the flexibility that is afforded to the customer to utilize more economical energy resources when they are available, and (4) to ensure that the non-firm pricing structure sends pricing signals that do not undermine the integrity of the firm service rate or facilitate the avoidance of economical firm service.

C. Stipulation to Assure Revenue Neutrality

The Company has filed a Stipulation with the Division to address the potential revenue effects from the migration of customers between firm and non-firm service, entitled: Stipulation Regarding Reconciliation of Revenues from Firm and Non-Firm Dual-Fuel Customers ("Stipulation") As stated in the Stipulation, depending upon the Commission's ruling in this docket on the appropriate non-firm service rate to apply on a going forward basis, the expectation of the Company and the Division is that there could be: (i) a migration of Firm Dual-Fuel Customers from firm service to non-firm service, or (ii) additional migration of Non-firm Dual-Fuel Customers from non-firm service to firm service. In either case, the customer migration would have the effect of causing either an under-recovery or an over-recovery of the revenue amount factored into the revenue requirement calculation in this case. For that reason, the Company and the Division agreed in the Stipulation to establish a reconciliation mechanism

to assure revenue neutrality for customers and the Company, regardless of the outcome of the Commission's decision on the establishment of non-firm rates. The details and purpose of the mechanism are fully set forth in the terms of the Stipulation and will not be repeated here. The Company urges the Commission to adopt the terms of the Stipulation to assure an equitable outcome on the revenue requirement in this case, regardless of how the rates for non-firm service are ultimately established.

D. Proposed Statement of Findings

1. The establishment of a "cost-based," fixed and/or discounted distribution rate for non-firm customers is not in the public interest because it establishes an improper disincentive for dual-fuel customers to avoid taking firm service when it would otherwise be in their economic interest to do so.

2. The establishment of a "cost-based' fixed and/or discounted distribution rate for non-firm customers that involves the allocation of costs to an "interruptible" rate class is not in the public interest because it would distort the rate design for firm service customers who utilize the system on a year-round basis.

3. The current value-of-service pricing recognizes that firm customers have paid for the distribution system, offset by non-firm revenues achieved over the years and they should benefit from the use of the system in off-peak periods.

4. The Company's proposal to cap its value of service price at 150% is reasonable and in the public interest in that it will mitigate cost increases for large and extra-large C&I customers, while ensuring that no incentive is created to avoid firm service where it is otherwise economic for the customer.

5. The Company's proposal to reintroduce "Flexible Firm Service" for customers using greater than 150,000 therms per year is approved, subject to Commission approval of any individual service agreements negotiated by the Company.

6. The Company's proposal to eliminate non-firm sales service is approved.

7. The Company's proposal to change the timeline for providing a distribution rate quote for the upcoming month 10 business days in advance to the 1st of the next month is approved.

8. The reconciliation mechanism reflected in the Stipulation is a just and reasonable means to assure an equitable result on the revenue requirement by assuring revenue neutrality between customers and the Company with respect to the potential migration effects of customers moving between firm and non-firm service and is approved.

VI. RATE DESIGN ISSUES, LOW-INCOME DISCOUNT RATES AND MISCELLANEOUS FEES

The Company has proposed a rate design to recover the allowed revenue requirement and that includes the creation of a low-income discount rate that would be applied to distribution rates in order to provide a 10 percent discount to eligible customers. The Company requests that the Commission make the following findings in relation to its proposed rate design and low-income rates:

1. The Commission finds that the Company's proposed rate design, including the establishment of a low-income discount rate is in the public interest and approved.

2. The Company shall filed a compliance filing following the Commission's determinations on the allowed revenue requirement to implement rates that will be applied to usage on and after December 1, 2008, as adjusted by the Commission's earlier order regarding the extension of time to consider the Company's application.

VII. CONCLUSION

The Company is grateful for the time and effort that all of the parties have put into this proceeding. From the Company's perspective, the Commission has conducted the proceeding in a manner that has allowed for a full and fair adjudication of the issues involved and the Company appreciates the opportunity to present its case in that context.