nationalgrid

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January 22, 2010

VIA HAND DELIVERY & ELECTRONIC MAIL

Luly E. Massaro, Commission Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02889

RE: Docket 4065 – National Grid Request for Change of Electric Distribution Rates
Initial Brief

Dear Ms. Massaro:

Enclosed please find ten (10) copies of National Grid's[1] Initial Brief in the above-referenced proceeding. Please note that the Company has included an updated revenue-requirement calculation to reflect certain corrections and changes identified by the Company in the course of responding to data requests issued since the close of hearings.

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 4065 Service List

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

RHODE ISLAND PUBLIC UTILITIES COMMISSION

	)	
The Narragansett Electric Company	)	
d/b/a National Grid	)	R.I.P.U.C. 4065
	)	

INITIAL BRIEF OF
The Narragansett Electric Company
d/b/a National Grid

Submitted by:

Thomas R. Teehan
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Dated: January 22, 2010

TABLE OF CONTENTS

I. INTRODUCTION 1

II. LEGAL STANDARD OF REVIEW 5

III. BASE REVENUE: REVENUE REQUIREMENT ISSUES 6

- A. Overview 6
- B. Capital Structure 8
- C. Return on Common Equity 13
- D. Rate Base Additions through the Rate Year 18
- E. Cash Working Capital 20
- F. Union Contract Labor Expense 21
- G. Variable Pay 23
- H. Merger-Related Synergy Savings 25
- I. Storm Fund Contribution 28
- J. Storm Expense 29
- K. Injury & Damage Expense 30
- L. Allocated Cost from the Service Company 31
- M. Vegetation Management Expense 34
- N. Inspection & Maintenance Expense 36
- O. Credit Collections Expense 40
- P. Customer Advocacy Expense 41
- Q. Legal Expense 41
- R. Rate Case Expense and Amortization 43
- S. Economic Development Expense 44

IV. PROPOSED RECONCILIATION FACTORS 45

- A. Introduction 45
- B. Uncollectible Expense Recovery 45

V. REVENUE DECOUPLING RATEMAKING PLAN 56

VI. RATE DESIGN ISSUES 58

I. INTRODUCTION

On June 1, 2009, The Narragansett Electric Company d/b/a National Grid ("National Grid" or the "Company") submitted a request for an increase in base distribution revenues in order to address a deficiency in operating revenues totaling $75.3 million. The Company's request for base-rate relief follows a 10-year period of flat or declining distribution rates made possible as a result of merger-related rate agreements approved by the Commission in Docket 2930 (2000) (annual reduction in distribution revenue of $12.4 million and rate freeze through December 31, 2004) and Docket 3617 (2004) (annual revenue reduction of $10.24 million and rate freeze through December 31, 2009).

However, while distribution rates have remained relatively constant over the past ten years, the Company's operating costs have not. Distribution rates were set to incorporate relatively significant cost reductions in administrative functions, customer-service resources and field operations arising from the consolidation of Narragansett Electric Company, Blackstone Valley Electric Company and Newport Electric Corporation; but, these cost reductions were not so great as to permanently offset the cost of inflation, rising costs of employee compensation and healthcare benefits, increasing uncollectible expense or the increasing expense and investment demands associated with maintaining, repairing and reinforcing the electric-distribution system.[1] Beginning in 2006, the Company also experienced relatively substantial declines in sales growth, which has historically served as a source of funding for utility operations between rate cases.[2] The combination of increasing costs and declining sales growth has had the inevitable effect of diminishing the Company's rate of return to 1.18 percent in 2008, which is a level that is insufficient to maintain access to reasonable cost capital and support funding of utility

[1] King Transcript, at 48-53 (Nov. 2, 2009); RR-COMM-7; RR-COMM-51.
[2] Schedule NG-APM-1.

operations. Therefore, although reasonable minds may differ on the *amount* of the revenue shortfall that exists at this point in time, there is no debate that a shortfall exists and that a revenue increase is needed to support electric utility operations in Rhode Island on a going-forward basis.

There is also no debate in this case that Rhode Island residents and businesses require reliable electric service as a matter of health, welfare and safety, as well as for economic viability. Although parties to this proceeding may have differing viewpoints on the acceptable level of service reliability, or the amount of investment required to achieve or maintain service reliability over time, there is no dispute that continual investment is needed to maintain, repair, replace and reinforce the system. In fact, the record shows that the current level of service reliability (SAIDI/SAIFI) has risen in the period 2006 to 2008 to an acceptable level, contemporaneous with increased spending on reliability in that same time period.[3] The record further shows that the Company has made these needed system investments notwithstanding a serious decline in the rate of return over the past few years.[4] However, it is clear to the Company and its investors that the situation is not sustainable and that the Company's rate of return must be addressed in this case if the Company is to continue to invest in its electric operations in Rhode Island.

In that regard, the rate of return realized by the Company following this case will be a function of two inter-related factors, which are: (1) the level of cost recovery (including a reasonable return) provided by the revenue requirement ultimately approved by the Commission in this case, and (2) the ability of the Company to collect the authorized level of revenues each year following the rate case. The record shows that investors' view of Narragansett Electric's

[3] DIV 11-3; DIV 14-11; RR-COMM-51.
[4] COMM 1-11.

overall financial stability and investment quality is extremely important.[5] The record also shows that investors are actively engaging the Company to emphasize the need to achieve a better rate of return.[6]

Conversely, it is in the interests of customers to establish rates that provide the Company with a fair and reasonable rate of return, because capital investment in Rhode Island can be maintained only so long as reasonable-cost capital is available to the Company. In turn, reasonable-cost capital is available to the Company only to the extent that the Company is able to realize and retain earnings (generated through utility rates), or to attract debt and equity investors. Although the expert testimony presented by the Division and the Company in this case establish a range of 10.1 percent and 11.6 percent, respectively, as an adequate return on common equity (assuming a capital structure with 47.50 to 50.05 percent equity), the testimony of the Company and the Division is in synch in recognizing that the Company will not maintain access to reasonable-cost capital if it cannot provide debt-holders and equity investors with an adequate return on the capital they have invested. Moreover, the imposition of a return on common equity or a capital structure that is relatively low in comparison to other electric utilities will put the Company in the position of having to seek base-rate relief on a continual basis because it will become impossible to absorb cost increases that have the effect of depressing an already low rate of return.

Recognizing that the investment community's expectations will need to be addressed if access to reasonable-cost capital is to be maintained, the Company is also fully cognizant and sensitive to the fact that the state of the economy is poor and Rhode Island residents and businesses are suffering. The Company knows that, given this state of affairs, the Commission's

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[5] Cannell Rebuttal Testimony; COMM 7-5; DIV 31-11 (see, also, COMM 1-10; DIV 4-22; DIV 11-38 and DIV 31-11; DIV 31-12).

[6] COMM 7-5.

instinct will necessarily (and appropriately) be to apply a heightened sensitivity to the interests of customers in terms of determining the costs that will result from this proceeding. However, the level of revenue and rate of return authorized by the Commission in this case is of importance to customers as well as the Company because both constituencies have a direct interest in maintaining investment in Rhode Island, maintaining service reliability, and in maintaining the availability of reasonable cost capital to fund operations. Therefore, the impetus to trim the Company's base-rate request and ratemaking proposals should be balanced with the recognition that adequate cost recovery, revenue stability, and the avoidance of relatively frequent rate cases are in the public interest.

In this initial brief, National Grid sets forth its legal analysis and proposed statement of findings in relation to its June 1, 2009 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 presents the legal standard of review applicable to the Commission's ratemaking decisions in this case.
- Section III discusses the proposed revenue requirement, with a focus on the issues that constitute the difference between the Division's position and the Company's adjusted rebuttal position, including return on equity and capital structure.
- Section IV discusses the Company's proposals for pension and PBOP expense reconciliation and uncollectible expense reconciliation.

- Section V discusses the Company's Revenue Decoupling Ratemaking Plan ("RDR Plan"), which encompasses (1) a revenue decoupling mechanism, and (2) certain annual "cost-side" rate adjustments allowing for inflation and timely capital-cost recovery.

- Section VI discusses the Company's rate-design proposals at issue in this proceeding.

II. LEGAL STANDARD OF REVIEW

In rendering its findings on the Company's revenue requirement and ratemaking proposals in this case, the Commission is obligated to make decisions "fairly and substantially supported by legal evidence." Newport Electric v. P.U.C., 624 A.2d 1098, 1101 (R.I. 1993); Valley Gas v. Burke, 518 A.2d 1363, 1365 (R.I. 1986); Roberts v. Narragansett Electric Co., 490 A.2d 506, 507 (R.I.1985); Roberts v. New England Telephone & Telegraph Co., 487 A.2d 136, 138 (R.I.1985); New England Telephone & Telegraph Co. v. Public Utilities Commission, 446 A.2d 1376, 1380 (R.I.1982); Chamber of Commerce Federation v. Burke, 443 A.2d 1236, 1239(1982); Michaelson v. New England Telephone & Telegraph Co., 121 R.I. 722, 404 A.2d 799 (1979); New England Telephone & Telegraph Co. v. Public Utilities Commission, 118 R.I. 570, 575, 376 A.2d 1041, 1044 (1977); and Rhode Island Consumers' Council v. Smith, 111 R.I. 271, 277 (1973). In addition to being "fairly and substantially supported by legal evidence," the Commission's findings must also be "sufficiently specific" to enable the Court "to ascertain if the facts upon which they are premised afford a reasonable basis for the result reached." Bristol County Water Co. v. Public Utilities Commission, 117 R.I. 89, 101-02, (1976); Rhode Island Consumers' Council v. Smith, 111 R.I. 271, 277 (1973). Since the Court does "not search the record for evidence that supports the Commission's decision or speculate as to the true reasons for its decision," the Commission is also obligated to "clearly set forth the findings and evidentiary facts upon which its decision rests." Bristol County Water Co. v. Public Utilities Commission, 117 R.I. 89, 101-02, (1976).

III. REVENUE REQUIREMENT ISSUES

A. Overview

In its initial filing, the Company calculated a revenue deficiency of $75,285,321 million, which included recovery through base distribution rates of $65,533,534 and recovery of commodity-related administrative and uncollectible costs of $9,751,787 through Standard Offer Service ("SOS") rates.[7] On rebuttal, the Company's calculation of the base-revenue deficiency was reduced to $63,586,000 (excluding SOS recovery), and further reduced to $63,267,000 in response to Division Data Request 27-1.[8] Lastly, through additional discovery in this proceeding, the Company has adjusted its calculation of the base-revenue deficiency to $62,229,000, as shown in Schedule NG-RLO-R-1, Update 2, which is provided as Appendix 1 to this Initial Brief. The Division's surrebuttal testimony calculated a base-revenue deficiency of $25,543,000, also excluding SOS recovery. In Appendix 1, the Company has modified the Division's surrebuttal position to $25,633,000, reflecting the amortization of updated rate-case expenses and a reduced IS leasing expenses identified by the Company in discovery. With the adjustments set forth in Appendix 1, the difference between the Company's updated position and the Division's adjusted surrebuttal position is approximately $36,597,000:[9]

Operating Expenses	$18.2 million[10]
Return on Rate Base	$11.3 million[11]
Income Taxes	$ 4.2 million
Distribution-Related Bad Debt Expense	$ 2.9 million
Total Difference	**$36.6 million**

7 O'Brien Direct Testimony, at 7.

8 O'Brien Rebuttal Testimony at 3; Schedule NG-RLO-R-1, at 1 (line 27, column (f)); Attachment 1 to DIV 27-1, at 2 (line 27, column (f)).

9 Effron Surrebuttal Testimony at Schedule DJE-10S.

10 Includes depreciation and amortization, loss on reacquired debt and taxes other than income taxes.

11 Includes impact of differences between Company and Division in ROE, capital structure and rate base.

Thus, the difference between the positions of the Company and the Division are the Division's operation and maintenance ("O&M") expense adjustments and a difference in the allowed return on rate base relating to: (1) the forecasted balance of net plant in service through the end of the rate year, (2) the appropriate return on common equity, (3) the percentage of common equity used in the capital structure, and (4) cash working capital.[12]

With respect to O&M expense, there are several items that comprise the difference between the Company's updated rebuttal calculation and that of the Division. These items are:

	Division Recommendation	in Millions
1.	Union Contract Labor	$1.36
2.	Incentive Compensation	$1.20
3.	Net Merger Synergy Savings (Company Share)	$0.59
4.	Annual Storm Fund Contribution	$1.04
5.	Reduce TY Storm Damage Expense	$1.40
6.	Economic Development Program	$1.00
7.	Service Company Allocations	$3.10
8.	Vegetation Management Adjustment	$1.86
9.	I&M Strategy Adjustment	$2.09
10.	Credit & Collection Initiative	$0.38
11.	Injury and Damage Expense	$2.50
12.	Rate-Case Amortization	$0.29
13.	Customer Advocate Expense	$0.18
14.	Legal Fees	$0.42
15.	Dep. Expense, Taxes Other than Inc. & Other	$0.76[13]
	Total Operating Expenses Subject to Dispute	**$18.17**

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 final costs,

12 Effron Surrebuttal Testimony at Schedule DJE-1S.

13 The difference in depreciation expense and other items such as income taxes and taxes other than income taxes is entirely related to differences in O&M expense and rate year plant in service. The Commission's final determination on these items will determine the expense level, and therefore, these items are not discussed herein.

including those incurred by the Commission and the Division that are chargeable to the Company, can be included in final rates.

CAPITAL STRUCTURE, RETURN ON EQUITY AND RATE BASE

B. Capital Structure

- *Company Testimony*

As of the test year, the Company's actual capital structure is composed of a large proportion of common equity (77.99%), exclusive of goodwill and accumulated other comprehensive income.[14] However, as indicated in the Company's initial filing on June 1, 2009, the Company is working to issue approximately $550 million of new long-term debt to repay short-term debt and make dividend payments in order to reduce its common equity ratio, exclusive of goodwill, to 50.05% for rate-setting purposes.[15] The actual capital structure of the Company also includes one issue of preferred stock and $58.5 million of outstanding long-term debt assumed when National Grid purchased the assets of the New England Gas Company and merged them into The Narragansett Electric Company.[16] Thus, the *actual capital structure* following the issuance would be comprised of 50.05% common equity, 44.78% long-term debt, 4.98% short-term debt and 0.19% preferred stock, which is the capital structure proposed by the Company in this case.[17]

In terms of the cost of long-term debt to be used for rate-setting purposes, the Company is proposing to use the actual cost of long-term debt as established by the issuance for the entire ratio of long-term debt (44.78%) included in the capital structure.[18] As stated above, a portion of this long-term debt was assumed at the time that the gas operations were acquired; however, the

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14 Moul Direct Testimony at 2-3.
15 Id. at 4.
16 Id. at Schedule NG-PRM-1, page 1 of 2.
17 Id.
18 Moul Direct Testimony at 4.

cost of that debt is currently being recovered through gas distribution rates set by the Commission in Docket 3943.[19] Thus, the Company proposes to use the effective cost rate of the new issuance for the entire debt ratio. For the preferred stock, the Company proposed to use the actual dividend rate of 4.50%.[20] For short-term debt, the Company proposes to use a cost rate of 2.50%, which is the average short-term debt interest rate projected for the 2010 rate year.[21]

- *Division Testimony*

The Division recommended that the Commission use a proxy capital structure composed of 47.33% long-term debt, 4.98% short-term debt, 0.19% preferred equity and 47.50% common equity.[22] The difference between the Company's capital-structure proposal and the Division's recommendation is that the Division seeks to include a larger percentage of long-term debt in the capital structure than would actually exist following the planned issuance (and conversely, a lesser percentage of common equity). Although Division Witness Kahal testified that "a reasonable target range for electric utility common equities today would be roughly 45 to 50 percent," Mr. Kahal recommends a common equity ratio of just 47.50% based primarily on the arguments that (1) the Company's anticipated debt issuance represents "just a plan or set of intentions," and (2) that Company Witness Moul has not shown that 50 percent is more appropriate than 47.50 percent in achieving a "cost minimizing capital structure."[23] Lastly, Division Witness Kahal recommends a long-term cost of debt of 5.6 percent and a short-term

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[19] Id.; COMM 14-5. It should be noted that the effect of *excluding* the long-term debt assumed in the New England Gas Company transaction would be to increase the equity component of the capital structure. Thus, the Company has included the debt in the capital structure, but excluded its cost.

[20] Moul Direct Testimony at 4.

[21] Id.; Schedule NG-PRM-1, at 1, fn.2.

[22] Kahal Surrebuttal Testimony at Schedule MIK-1, page 1 of 2.

[23] Kahal Direct Testimony at 16; Kahal Surrebuttal Testimony at 4.

cost of debt of 1.6 percent.[24] Division Witness Kahal does not object to using 4.50 percent as the dividend rate for the preferred stock outstanding.

- *Legal Analysis*

On December 9, 2009, the Division approved a settlement between National Grid and the Division authorizing the issuance of up to $550 million of long-term debt prior to March 31, 2010. National Grid, D-09-49, Order No. 19847 (2009) (Settlement Agreement at Paragraph 1).[25] The Company is working diligently to complete this issuance so that the results may be incorporated into rates resulting from this proceeding. This issuance will determine both the ratio of long-term debt (and conversely the ratio of common equity) existing in the Company's actual capital structure and the cost of long-term debt for rate-setting purposes. Completion of the issuance will allow for the inclusion of the final amounts and cost of long-term debt in the revenue requirement.

As described above, the Company is requesting that the Commission set rates in this proceeding using the actual capital structure, cost of long-term debt and preferred-stock rate that will exist after the approved debt issuance. The actual capital structure will be known and measurable at the time that rates are set and the Commission's precedent is to use a company's actual capital structure where a reasonable capital structure exists for ratemaking purposes. Even when the Commission has approved a departure from an actual capital structure, it has imputed a capital structure on par with the Company's recommended 50.05 percent. See, e.g., Blackstone Valley Electric, Order No. 13877 (1992) (using actual capital structure); The Narragansett

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24 Kahal Surrebuttal Testimony at 2.

25 Based on the Company's actual capital structure as of November 2009, the Company will need to pay a dividend of approximately $330 million and use the remaining $220 million to pay down short-term debt in order to achieve a debt/equity ratio of 50/50. These figures may change to a slight degree based on the actual capital structure through January 31, 2010. This is because the amount of retained earnings generated between November and the end of January will impact the size of the dividend payment. See, COMM 15-1.

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 Division's recommendation to use a proxy-group generated equity ratio of 47.50 percent is based on two propositions, which essentially are that the planned debt issuance is speculative and that the Company has not demonstrated that an equity component of 50.05 percent is "cost minimizing." However, the facts are that the issuance is no longer speculative and is anticipated to occur prior to the finalization of rates in this proceeding. Secondly, there is no legal or ratemaking standard that requires the Company to demonstrate that its capital structure is "cost minimizing," as suggested by Division Witness Kahal. In fact, Mr. Kahal testified that "a reasonable target range for electric utility common equities today would be roughly 45 to 50 percent," which encompasses the Company's actual equity ratio.[26] His recommendation of 47.50 percent simply represents an arbitrarily selected midpoint of that range.[27] However, where there is an actual capital structure in place, and where that capital structure is reasonable for ratemaking purposes (and Division Witness Kahal has testified that an actual equity ratio of 50 percent would be reasonable), there is no valid basis for the imposition of a lower equity ratio.

On January 12, 2010, the Commission posed a 15th set of discovery in this proceeding, which asked several questions regarding the use of National Grid plc's capital structure for ratemaking purposes in this proceeding. No party is recommending the use of the National Grid

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26 Kahal Direct Testimony at 6, 18.
27 Id. at 18.

plc capital structure and there is no testimony or evidence on the record supporting its use or in any way indicating that it could or would be reasonable or appropriate. Moreover, because no party has made such a recommendation, the issue has not been litigated in this proceeding.

These facts are important because the Commission is legally obligated to make decisions that are "fairly and *substantially* supported by legal evidence." See, e.g., Newport Electric v. P.U.C., 624 A.2d 1098, 1101 (R.I. 1993); Valley Gas v. Burke, 518 A.2d 1363, 1365 (R.I. 1986) (emphasis added). In addition, the Commission's longstanding precedent is to use a company's actual capital structure, or if the actual capital structure is unreasonable for ratemaking purposes, then to use a proxy that puts the utility on par with comparable electric utilities in the marketplace. Thus, there is neither Commission precedent, nor "substantial evidence" in the record for the proceeding to support the imposition of National Grid plc's capital structure. The legal evidence "fairly and substantially" supports a capital structure with an equity component ranging from 47.50 to 50.05 percent. Accordingly, the imposition of National Grid plc's capital structure cannot be legally justified in this case.

- *Requested Commission Findings*

1. The Commission should adhere to its established ratemaking precedent and render a determination to use the Company's actual capital structure and cost of long-term debt resulting from the issuance of long-term debt pursuant to the Division Docket D-09-49.

2. Assuming the issuance of up to $550 million of long-term debt, the authorized capital structure used for setting rates in this proceeding shall be comprised of 44.78 percent long-term debt, 4.98 percent short-term debt, 0.19 percent preferred stock and 50.02 percent common equity.

C. Return on Common Equity

- *Company Proposal*

The Company has proposed a weighted average cost of capital of 8.98 percent and a return on common equity of 11.60 percent.[28] The cost of common equity was derived by the Company using capital market and financial data for seven electric or combination electric and gas utility companies, which currently have some form of revenue-decoupling mechanism in place.[29] 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.[30] Focusing on the market-based model approaches (i.e., DCF, Risk Premium and CAPM), the Company calculated that the average equity return produced is 11.66 percent.[31] Therefore, the Company proposed a cost of common equity of 11.6 percent.[32] Company Witness Moul also testified that he evaluated the appropriate cost of common equity using a group of companies without a revenue decoupling mechanism in place and this analysis showed that the Company's authorized return on common equity should be 30 basis points higher if revenue decoupling is not allowed.[33]

- *Division Testimony*

The Division's witness recommended a weighted average cost of capital of 7.54 percent for National Grid with a return on common equity of 10.1 percent.[34] Division Witness Kahal stated that, in calculating his recommended return on common equity, he relied primarily on the

28 Moul Direct Testimony at 6; Schedule NG-PRM-1, page 1.
29 Id. at 5-6.
30 Id.
31 Id. at 8.
32 Id.
33 COMM 31-4.
34 Kahal Surrebuttal Testimony, MIK-1, at page 1 of 2.

DCF model applied to a group of electric distribution companies and to a second group of natural gas distribution utilities, with the result ranging from 9.7 percent to 10.7 percent for the combined gas and electric group.[35] The recommendation of 10.1 percent represents the midpoint of that range.[36] Although the Division argued that the implementation of revenue decoupling would shift risk away from the Company, it provided no quantification of any adjustment.[37]

- *Analysis*

In terms of the mechanics of the calculations put forward by Company Witness Moul and Division Witness Kahal, there are a number of judgments that each witness has made to produce a recommended return on equity ranging from 10.1 to 11.6 percent. However, there are two considerations relating to the Commission's final determination on ROE in this proceeding that argue for an ROE greater than 10.1 percent:

First, while the Company appreciates the fair and balanced approach taken by Division Witness Kahal, there is a methodological issue involved in his calculation. Specifically, Division Witness Kahal's recommendation for the return on common equity is based on his analysis of the DCF model employing two proxy groups, with one group composed of nine gas companies and one group composed of seven electric companies; however, he has not applied the DCF analysis on a symmetrical basis for his gas and electric proxy groups.[38] For the gas company proxy group, Division Witness Kahal calculates a total return range under the DCF analysis of 9.7 to 10.2 percent and a midpoint range of 10.0 percent.[39] The range of 9.7 to 10.2 percent is derived by first calculating a dividend yield estimate of 4.7 percent (based on the average of nine gas utilities), and then adding an earnings-per-share growth rate. For the earnings-per-share growth

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35 Kahal Direct Testimony at 7.
36 Id.
37 Id. at 10.
38 Id. at 31.
39 Id. at 37.

rate, Division Witness Kahal calculated a rate of 5.24 percent (based on an average of four data sources), and then added a *symmetrical deadband of 25 basis points* before adding the growth rate to the dividend yield. More specifically, he added an earnings growth rate of 5 percent (5.24 percent minus 25 basis points) and 5.5 percent (5.24 plus 25 basis points) to the 4.7 percent dividend yield to produce his DCF range of 9.7 to 10.2 for the gas company proxy group.[40]

For the electric company proxy group, Division Witness Kahal calculated a range of 9.7 to 10.7 percent, with a midpoint range of 10.2.[41] Precisely as he did with his gas proxy group, Division Witness Kahal derived the range by first calculating a dividend yield estimate of 5.9 percent (based on an average of seven electric utilities).[42] Also as he did with the gas utilities, Division Witness Kahal then calculated an earnings-per-share growth rate of 4.87 percent (based on an average of the same four data sources).[43] However, instead of using a symmetrical deadband of 25 basis points to estimate the growth rate like he did for the gas companies, Division Witness Kahal *reduced* the calculated earnings-per-share growth rate by more than 100 basis points before adding it to the dividend yield, which had the singular effect of pulling down the earnings-per-share growth rate, and consequently the DCF result for the electric proxy group.[44] Specifically, with an *asymmetrical reduction of 100 basis points* to the average growth rate, the earnings per-share-growth rate added to the dividend yield by Division Witness Kahal is 3.8 percent and 4.8 percent (i.e., 4.87 percent minus 1.07 percent and 0.7 percent), which in turn, creates a DCF result of range of 9.7 to 10.7, when added to the dividend yield of 5.9 percent.

Division Witness Kahal conceded that, had he used the same, symmetrical 25 basis point range as he used for the gas companies, the earnings per share growth rate would have ranged

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40 Tr. at 135-139 (November 12, 2009).
41 Kahal Direct Testimony at 42.
42 Tr. at 142 (November 12, 2009).
43 Id. at 142-143.
44 Kahal Direct Testimony at 42; Tr. at 146, lns. 6-12 (November 12, 2009).

from 4.62 to 5.12 percent, which would have resulted in a DCF result of 10.6 to 11.1 percent, instead of 9.7 to 10.7.[45] Division Witness Kahal further conceded that, if the same mathematical methodology was used for the gas and electric proxy group calculations, the result of his DCF calculation would be 10.4 percent.[46]

Second, the record shows that the range of ROEs presented in this case is reasonable and in line with regulatory standards. For example, the Company's response to Division Data Request 31-10 presented a copy of a report on Major Rate Case Decisions, dated October 2, 2009, prepared by the Regulatory Research Associates. This document reports that average rates of return on common equity for electric utilities has averaged 10.43 percent with no decision in 2009 falling below 10.00 percent, except in the case of United Illuminating (CT), which has been universally recognized as having a significant negative impact in financial markets.[47] These results are validated in the Company's response to DIV-12.

The Company has indicated throughout this proceeding that it is vital that the Commission set a fair and reasonable rate of return 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. 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.[48] The record further shows that market analysts are pinpointing the needed return at greater than 10.5, so that given all other cost and financial considerations affecting the Company, the *earned* ROE will exceed 10.5 percent.[49] Moreover,

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45 Tr. at 143-144, 151-152 (November 12, 2009).
46 Id. at 152.
47 DIV 31-10, Attachment at page 2-7.
48 Cannell Rebuttal Testimony; COMM 7-5; DIV 31-11 (see, also, COMM 1-10; DIV 4-22; DIV 11-38 and DIV 31-11; DIV 31-12).
49 Id.

the Company's testimony shows that the ROE should be 11.6 percent, but in any event, should be adjusted upward by 30 basis points if revenue decoupling is not approved.[50] Lastly, the Division's testimony supports an ROE in excess of 10 percent, and would be even higher had Division Witness Kahal used a consistent methodology for computing the DCF range for his gas and electric company proxy groups. For this reason, and based on the weight of the record evidence establishing a range of 10.1 to 11.6 percent, the Commission should establish a return on common equity that is in line with industry standards.

Lastly, although there is no substantiation for such a decision in the record for this proceeding, the Commission has recently inquired as to the imposition of National Grid plc's capital structure for ratemaking purposes. The Company's response explained that increasing the debt ratio to 62 percent would require a 1.31 percent increase to the Company's proposed 11.6 percent rate of return on common equity due to the higher degree of financial risk associated with this exceptionally high debt ratio.[51] However, even if made, this adjustment would not address the negative impacts that have the potential to result from a credit rating downgrade if the Commission were to set rates based on a 62 percent debt ratio.

The Company's response to COMM 15-6 shows that, by the benchmarks published by Standard & Poor Corporation ("S&P"), a utility is deemed to have a "highly leveraged" financial profile if its debt ratio exceeds 60 percent.[52] Based on S&P's ratings criteria a debt ratio of this magnitude would be representative of low to non-investment grade (i.e. junk bond) credit quality. In contrast, the current financial profile of Narragansett Electric is "significant," which encompasses a debt ratio in the range of 45 percent to 50 percent, and is consistent with the Company's proposed capital structure in this proceeding and its current A- credit rating.

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[50] DIV 31-4.
[51] COMM 15-6.
[52] Moul Rebuttal Testimony at 8.

Therefore, a 62 percent debt ratio is entirely incompatible with Narragansett Electric's current A- credit rating and could result in a ratings downgrade, which would increase the cost of new long-term debt issued by the Company and, depending on the severity of the downgrade, impair its ability to access the capital markets. This is not a result that is in the interests of customers.

- *Recommended Commission 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 11.6 percent based on a proxy group of comparable regulated electric companies, operating with a revenue decoupling mechanism in place. The Division's calculation is at 10.1 percent. Therefore, the Commission should set the return on common equity consistent with the record evidence in this proceeding.

2. The record shows that, without a revenue decoupling mechanism in place, the Company's allowed ROE should be set approximately 30 basis points higher, all else being equal.

D. Rate Base Additions through the Rate Year

- *Summary of Company Proposal*

Based on the updated rebuttal testimony of Company Witness O'Brien provided as Schedule NG-RLO-R-1, Update 2, the Company calculated a rate base for the rate-year ending December 31, 2010 of $616,435,000, which is based on a five-quarter average for the rate year with $1,232,478,000 for electric plant in service.

- *Discussion and Review of Record Evidence*

The Division argued that the Company's actual rate of capital spending following the test year is lower than the Company's forecasted spending, and that the Company is overstating its capital additions based on those actual expenditures. Therefore, the Division recommended a reduction in forecasted capital additions through the rate year of $31,877,000, which constitutes a proposed reduction of $19,953,000 to average rate year plant in service. The Division also proposed an increase in accumulated depreciation amounting to $5,286,000, for an increase in average accumulated depreciation for the rate year of $2,331,000. Therefore, the Division's proposed net plant-related rate-base adjustments amount to ($37,163,000), for a total proposed average rate-year rate base adjustment of ($22,284,000).

In rebuttal testimony and at the evidentiary hearings, Company Witness Pettigrew confirmed that actual capital spending in 2009 was below the budgeted amount through the fiscal year end (year ending March 31, 2010), although not to the substantial extent of the $31.9 million reduction through the end of the rate year asserted by the Division.[53] Specifically, Company Witness Pettigrew confirmed that: (1) in FY2007 and FY2008, the Company's actual spending exceeded the forecasted budget on a full fiscal year basis; (2) the only year in the past three that the Company had fallen below the budgeted amount was FY2009, with the shortfall totaling only $2.5 million, and (3) the spending lag in FY2010 was attributable to a single substation project in Newport, Rhode Island, which is currently experiencing delays because of land-use issues.[54] Lastly, Company Witness Pettigrew testified that the Company does not spend its capital budget on an even monthly basis and that a greater level of spending may occur toward the latter part of the fiscal year.[55] Given the testimony of Company Witness Pettigrew, it is clear that actual spending will be less than what the Company originally forecast, but not as far short as suggested by the Division.

As in Docket 3943 in 2008, the Division's recommended disallowance is based solely on a linear spending trend, which is likely to underestimate the Company's spending through the end of the rate year given the circumstances explained by Company Witness Pettigrew. Based

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53 Pettigrew Rebuttal Testimony at 20-21; Tr. 2, at 28 (November 3, 2009).
54 Id.
55 Pettigrew Rebuttal Testimony at 20-21.

on its knowledge of the work flow, the Company's assessment of its capital spending shortfall is far less than the $31.9 million shortfall asserted by the Division, especially given that the shortfall is primarily attributable to one large capital project delayed for reasons beyond the Company's control.[56] Therefore, the effect of following the Division's recommendation would simply be to penalize the Company for a non-linear spending pattern over the course of the year. In the final result, the Company is not seeking to include any more or less capital spending in rates than what actually occurs through the end of the Rate Year, and therefore, an abstract debate about the possible amount of capital spending actually occurring through December 31, 2010 is not necessary. Instead, the Company proposes to apply the mechanism developed in Docket 3643 to reconcile collections to the actual spending amount. See, Docket 3943, Order No. 19563, at 24-25**.**

- *Recommended Commission Findings*

1. The Commission should set rates to incorporate net plant additions through the end of the Rate Year and allow the Company to reconcile its actual net plant in service to that amount (whether greater or less) through the same mechanism allowed by the Commission in relation to Docket 3943.

E. Cash Working Capital

The Division claims that the lead or lag in payment should reflect the time between the payment of municipal taxes and the recovery of the tax expense from customers.[57] The Division further claims that, because the Company's expenses are based on accrual accounting both for book and ratemaking purposes, the lead or lag in payment should be based on the accrual of the expense over the course of the year, rather than the "fiscal year of the taxing authorities.[58] However, the Company does not agree that the point of accrual of the expense is the appropriate

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56 Id. at 21.
57 Effron Surrebuttal Testimony at 15.
58 Id.

point to be measured in determining the lead or lag in payment. The Company correctly matches the service periods for municipal taxes and conforms that portion of the cash working capital calculation to the remaining portions. In the case of municipal taxes, the Commission should determine that the service period for the municipal taxes is the tax period for the actual taxes being paid by the Company (i.e., the 12-months ended June 30 rather than the rate year). In most cases, the service periods are within the Company's test period (for example, payroll-service periods occur weekly, bi-weekly or monthly within the test year), but some costs (like municipal taxes) occur outside of the test period. In those cases, it is appropriate to use the period the municipality provides service (July 1 to June 30) and not the test period. Therefore, the payment lag for municipal taxes should be based on the period the municipality provides the service it is charging for.

OPERATING EXPENSES

F. Union Contract Labor Expense

The Division is disputing the inclusion of approximately $1.363 million of labor expense arising from a contractual commitment made by the Company with its collective bargaining units.[59] While not disputing that the Company is contractually committed to incur this cost, the Division claims that the cost should be excluded from the approved revenue requirement because "[t]he model contemplated in the union contracts is clearly one with more employees and relatively fewer contractors," therefore "it is only logical to conclude that the increase in staffing will be at least offset by reductions to outside contractor expense."[60]

There are two main problems with this recommendation: (1) the union contracts refer to the substitution of employees for a specific type of contractor (i.e., "platform contractors,") and

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59 Effron Direct Testimony at 7-8; Effron Surrebuttal Testimony at 2-3.

60 Effron Surrebuttal Testimony at 3.

do not govern, address or limit the use of other types of contractors, and (2) the Division has presented no analysis of costs or the trade-offs in cost between internal and external labor, if any. Consequently, there is no record evidence to support the Division's "logic" on this issue.

To the contrary, the record shows the following: (1) Company Witness Pettigrew testified that, based on the volume of work that the Company expects to undertake (for both maintenance and capital), it will be increasing the overall number of contractors working on the system and the increase in union labor will not offset or reduce the use of outside contractors;[61] (2) Company Witness Dowd testified that union contracts refer to "platform contractors," who represent only a small subset of the total contractors utilized by the Company and a small "slice" of the overall contractor expense incurred by the Company,[62] and (3) Company Witness Dowd testified that the magnitude of work undertaken on the Rhode Island distribution system is a matter of management discretion, as is the hiring of contract labor, so that the Company would not be precluded from moving forward with its planned/increased work scope.[63]

In terms of the testimony of Division Witness Effron, the record shows the following: (1) when making his recommendation, he did not have an understanding of the term "platform contractors," as used in the union contract; (2) he does not have knowledge of the categories of contractors or number of contractors used by the Company other than platform contractors; (3) he does not have knowledge of the expense of contractors in proportion to platform contractors and whether that cost has increased since the inception of the union contract in 2007, and (4) there is no prohibition against the hiring of outside contractors contained in the union contract.[64]

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[61] Tr. at 155-56 (November 3, 2009).
[62] Tr. at 97-98 (November 5, 2009).
[63] Tr. at 98 (November 5, 2009).
[64] Tr. at 208-210 (November 5, 2009).

As a result, there is no record evidence in this proceeding supporting the Division's logic that the cost of the increase in union labor will be offset by reductions in contractor expense. The Company is contractually committed to the cost; the Company has explained that the contract provision has limited applicability; the Company has confirmed that its contractor costs will not be reduced because of increasing work requirements, and there is no other evidence that this cost will be offset in whole or in part by reduced contractor expense. Accordingly, there is no basis for the disallowance of this cost.

G. Variable Pay

The Division is recommending the disallowance of $1,204,000, which represents 50 percent of the Company's cost of incentive compensation paid to employees.[65] The Division asserts that this portion of incentive compensation should be denied by the Commission on the basis that it relates to the attainment of financial goals such as earnings or return on equity, which are goals that are not serving the interests of customers.[66] Division Witness Effron further asserts that, if the incentive compensation program is effective, then the program should pay for itself.[67] However, aside from the simple assertion that variable pay earned as a result of the achievement of financial goals is not appropriate for recovery from customers, the Division offers no justification for disallowance of these costs. Conversely, the record shows substantial evidence supporting its inclusion in the cost of service.

Specifically, the record in this case shows that (1) incentive compensation paid to all "Band A" employees, who are employees with the most direct responsibility for the financial goals of the corporation, is excluded from the cost of service;[68] (2) incentive compensation is not

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65 Effron Direct Testimony at 5-6; Effron Surrebuttal Testimony at 1-2.
66 Id.
67 Effron Surrebuttal Testimony at 2.
68 Tr. at 159-160 (November 5, 2009).

a bonus; it is the variable component of an employee's compensation, which is designed to motivate the employee to work to the benefit of the Company and its customers in a variety of ways;[69] (3) without a variable pay component, 100 percent of an employee's compensation would be allowable in rates;[70] (4) Division Witness Effron conceded that employees who were paid 100 percent of their compensation in base (non-variable) salary would be spending some portion of time working on goals that would benefit shareholders;[71] (5) the Company's total compensation levels, including variable pay, are set to be comparable with total compensation levels of competing employers, and therefore, the disallowance of 50 percent of this cost puts the Company at a competitive disadvantage for skilled employees;[72] (6) Division Witness Effron does not have experience in structuring employee compensation programs, does not recall reviewing the Company's (Towers Perrin) compensation study and has not performed his own evaluation of prevailing employee-compensation standards in order to support his recommendation;[73] (7) Division Witness Effron is not disputing the reasonableness of the Company's overall employee compensation expense, including variable pay;[74] (8) Division Witness Effron conceded that, if the variable compensation is disallowed, it would reduce the Company's earned return all else being equal,[75] and (9) Division Witness Effron conceded that "customer-oriented" goals include cost reduction, which also would have the effect of increasing a company's earnings.[76]

In fact, the Division has no basis for disallowance of $1,204,000 in cost that will be incurred by the Company other than the single assertion that the pay is linked to the achievement

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69 Tr. at 199 (November 5, 2009).
70 Tr. at 199 (November 5, 2009).
71 Tr. at 200 (November 5, 2009).
72 Dowd Rebuttal Testimony at 4-5.
73 Tr. at 194-196 (November 5, 2009).
74 Tr. at 198 (November 5, 2009).
75 Tr. at 203 (November 5, 2009).
76 Tr. at 203-204 (November 5, 2009); Tr. at 6-7 (November 6, 2009).

of earnings or the rate of return. The Division disregards the fact that the variable pay component represents an accepted compensation structure that is prevalent in today's economy; that the Company must establish compensation programs consistent with opportunities in the marketplace to attract and retain skilled personnel, which is in the interests of customers; that the Company's total compensation is set at the median of industry standards (i.e., *below higher levels available in the market place*) even with variable pay included; that even "customer-oriented" goals accepted by the Division have the effect of increasing earnings; that a lack of earnings and a reasonable rate of return will factor into the cost of capital, which is borne by customers; that lots of programs contained in rates may be cost beneficial (i.e., generate benefits that cover the cost), and if all of these programs were disallowed from rates, the Company would be unable to earn its rate of return because it would not be recovering the cost of running the system, including the costs incurred labor resources. Lastly, validity of the Division's claim is undermined by the implication that, if the Company just restructured the plan to specifically refer to "cost reduction" instead of "the achievement of earnings," which are inextricably related concepts, the Division would not object to its inclusion in rates. For all of these reasons, there is no basis for the disallowance of a valid and reasonable cost incurred by the Company to provide efficient utility service.

H. Merger-Related Synergy Savings

The Division is disputing the calculation of costs to achieve ("CTA") and net merger synergies to be included in rates in relation to the National Grid/KeySpan merger and recommending the disallowance of $1,176,000 in relation to that calculation.[77] In the past, the Commission has allowed a 50/50 sharing of savings achieved in "O&M" cost reductions, net of

[77] Effron Direct Testimony at 8-11; Effron Surrebuttal Testimony at 22-24.

the cost of achieving those savings amortized over a 10-year period.[78] 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. There is no dispute in this case over the 50/50 sharing of net benefits between the Company and customers.[79] Although the Company followed this rule in calculating the revenue requirement adjustment resulting from the merger, the Division's claim is that the National Grid/KeySpan merger occurred in late 2007, and therefore, the accounting for the costs and savings experienced in 2008 and 2009 should differ from previous cases involving a straight 10-year amortization period for the costs to achieve.[80]

The Division's recommended downward adjustment to the revenue requirement of $1,176,000 arises from a reduction in the amount of CTA included in the calculation. Specifically, the Company's calculation is that a total of $8,600,000 in annual steady-state cost reductions are anticipated to result from the merger, of which $2,400,000 is captured in the test-year O&M totals. Therefore, for the revenue requirement, the Company subtracts the annual amortization of $2,100,000 of CTA from the annual steady state savings of $8,600,000, resulting in net steady state synergy savings of $6,250,000. This amount is then shared 50/50 between customers, resulting in a total of $3,250,000 in net savings (or $8.6 million in savings less $2.1 million in costs divided by 2), built into rates for the benefit of customers.[81] The Division argues that the Company actually incurred $8,610,000 in CTA in 2008 and 2009, and since the savings realized (and retained) in those years exceeds that amount, then the Company should be allowed to recover only the remaining CTA, which total $7,395,000 or $924,000 per year over 8 years

[78] See, e.g., New England Gas Company, Docket 3401, Order No. 17381 (2002).
[79] See, e.g., Tr. at 216 (November 5, 2009).
[80] Effron Direct Testimony at 22-23; Effron Surrebuttal Testimony at 10-11.
[81] O'Brien Direct Testimony at 46-47.

(i.e., a 10-year period, less 2008 and 2009). The net effect of including CTA amortization of $924,000 in the revenue requirement instead of the Company's proposed $2.1 million is a reduction to the revenue requirement of $1,176,000.

Essentially, the Division's recommendation is to apply the Commission's established standard for inclusion of merger-related cost savings in rates with a 50/50 sharing between the Company and customers, net of the costs to achieve those savings, but starting with the "unrecovered" costs and savings *occurring in 2010* (and going forward for eight years), rather than starting with a 10-year amortization of *total* anticipated costs and savings as if the merger had just occurred. Although the Company does not disagree with the premise of building an amount into rates that represents what will actually be achieved in the eight-year period going forward from 2010, the calculation put forth by Division Witness Effron is only partially correct.[82] Specifically, because his calculation has the effect of reducing the annual amortization of costs, the annual amount of net synergy savings that will be experienced each year, and that would be shared, would automatically increase. However, he has not re-computed this 50/50 allocation of savings between the Company and customers. In other words, by reducing the annual cost amortization to $924,000 (from $2,100,000), he has increased the savings available each year by the $1,176,000 he is proposing to take out of rates. To be consistent with the 50/50 sharing rule, this amount would have to be shared with the Company ($1,176,000/2 = $588,000).[83]

Consequently, the Company agrees that a reasonable and appropriate resolution to this dispute would be to reduce the Company's proposed revenue requirement by a total of $588,000

[82] Tr. at 216-219 (November 5, 2009).

[83] This amount is also calculated by taking total annual savings of $8,200,000, less $924,000 in costs to achieve, or $7,676,000, divided by 2, which equals $3,838,000 in annual savings for customers and for the Company instead of the $3,250,000 calculated by the Company and included in the case. Tr. at 216-219 (November 5, 2009).

rather than the $1,176,000 recommended by the Division. The amount of $588,000 represents the additional savings available to be shared as a result of commencing the merger calculation in 2010 based on the costs and savings to be incurred over the next 8 years.

Lastly, the Division took issue with the proposal for including the Company's share of merger-related savings in rates in future rate proceedings.[84] In the surrebuttal testimony of Division Witness Effron, the Division recommended that, in any rate case more than four years from the present case, the Company would have to present proof of continuing savings in order to include the shared savings line item in its revenue requirement.[85] The Company agrees with this proposition.

I. Storm Fund Contribution

The Company has proposed to continue accruing an annual contribution to the Storm Fund of $1,041,000 and the Division is proposing to end this contribution.[86] As explained by Company Witness O'Brien, a reasonable resolution to this dispute would be the following: (1) suspend the annual accrual through rates, which would reduce the revenue requirement by $1,041,000 as suggested by the Division, and (2) establish a threshold for reinstatement of the annual accrual that would be triggered in the event that the fund were to decline below $20 million.[87] As indicated by Company Witness O'Brien, the $20 million represents one third of the cost incurred for the Company's Massachusetts operations in 2008 for a single storm event, coincident with the fact that the Rhode Island operations are approximately one-third the size of

[84] Effron Direct Testimony at 23; Effron Surrebuttal Testimony at 11.
[85] Effron Surrebuttal Testimony at 11.
[86] Effron Direct Testimony at 16.
[87] Tr. at 31-33 (November 5, 2009). The Company has not reflected this proposal in the updated cost of service provided herewith as Appendix 1.

the Massachusetts operation.[88] This would alleviate costs for customers now, but would not jeopardize the availability of funds should a significant weather event occur in the future.

J. Storm Expense

The Division is recommending that the Commission reduce the revenue requirement by $1,395,000 to "normalize" the amount of storm expense to be included in rates, with the "normalized" amount equal to the five-year average of expense.[89] The Division derived this reduction by averaging the Company's recorded storm expense for the five-year period 2004 through 2008, which equals $3,105,000, and then deducting the five-year amount from the test year amount of $4,410,000.

The Company strongly disagrees with the contention that the amount of $3,105,000 is "normalized" or is representative of the amount that will be incurred for this expense in the future. As an initial matter, Division Witness Effron claimed in his Direct Testimony that the reason he was "normalizing" storm expense is because the amount originally reported by the Company, or $5,168,000 was substantially higher than past years.[90] When the Company corrected the amount from $5,168,000 to $4,410,000, the annual expense amount came into line with past years, the argument shifted to the "fluctuation" between years, rather than the expense being significantly higher than other years.[91] However, the "fluctuation" referenced by Division Witness Effron during the period 2004 through 2008 is within the range of $2.9 million to $4.4 million, with the exception of 2004, which totaled $437,000. Thus, the primary reason that the five-year average deviates from the test-year expense is that the storm expense recorded in 2004 was only $437,000, which is approximately *654 percent less* than the next lowest year ($2.9

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88 Id.
89 Effron Surrebuttal Testimony at 5-6.
90 Effron Direct Testimony at 18; Tr. at 222-223 (November 5, 2009).
91 Tr. at 223 (November 5, 2009).

million in 2007).[92] The record also shows that, excluding 2004, the Company's storm expense was less than the $3.1 million amount recommended by the Division in only one of the remaining four years (i.e., $2.9 million in 2007).[93] Lastly, Division Witness Effron acknowledged that he had not performed any analysis of the numbers reported to determine the number of storms reflected in the expense so that he has no basis to assert that the expense reported in 2004 is accurate, reasonable or appropriate for inclusion in a "normalizing" calculation.[94]

The Company does not agree that there is any basis for adjusting the test-year storm expense in this case. The Division has made no claim that the Company's test-year storm expense is inaccurate or unreasonable, except that the cost fluctuates over time as does every other cost that the Company incurs. If the Commission were inclined to adopt the Division's recommendation to "normalize" this expense, the Commission should exclude the data for 2004 because the 2004 amount is uncharacteristically low as compared to other years, such that factoring this amount into the averaging calculation substantially distorts the resulting "normalized" amount.

K. Injury & Damage Expense

The Division is recommending that the Commission reduce the Company's test-year level of injury and damage expense by $2,500,000 to eliminate the impact of an increase in the reserve associated with a single personal injury event that occurred on the Company's system. As an initial matter, the Company has indicated that the reserve amount associated with this single event was $2,225,000, rather than $2,500,000.[95] The record also shows that this incident

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92 Tr. at 230 (November 5, 2009).
93 Tr. at 228 (November 5, 2009).
94 Tr. at 226 (November 5, 2009).
95 RR-COMM-19.

involves a work-site injury resulting from contact with an energized overhead line, which unfortunately has the potential to re-occur. In fact, the Company showed that the total expense level for Injury & Damage expense was on par with prior years, and therefore, there is no basis for excluding the $2,225,000 in 2008.[96]

L. Allocated Cost from the Service Company

The Division is recommending the disallowance of $3.1 million in costs allocated to the Company from the Service Company. Of this amount, $2.3 million was recorded in Account 583 and is associated with the cost of the New England Overhead GIS Survey Project. The remaining $800,000 pertains to Account 588 and represents 50 percent of the costs associated with the Company's electric transformation initiative. However, the record does not support either of these adjustments.

With respect to Account 583, Division Witness Smith advocates for the reduction of $2.3 million based on a claim that the Company's going forward GIS expense will be less than the 2008 expense and, allegedly, will be reduced to zero in 2010, when rates go into effect.[97] Based on this faulty conclusion, Division Witness Smith's recommendation is that the Commission should disallow the cost of the New England Overhead GIS Survey because it is not a recurring expense.[98] In her surrebuttal testimony, Division Witness Smith adds that the GIS expenditure was not justified by a cost/benefit analysis.[99]

In fact, the record shows that the Company will incur going forward costs in relation to GIS surveys. Company Witness Pettigrew testified that: (1) costs incurred in the past were associated with a survey of the overhead distribution system, and that the Company already had a

96 RR-COMM-22.
97 Smith Direct Testimony at 15-16.
98 Smith Direct Testimony at 17.
99 Smith Surrebuttal Testimony at 2.

new, significant survey underway with respect the underground distribution system, which will cause the Company to incur costs through 2010 and beyond;[100] (2) although the costs of the Company's GIS program varies from year to year, the costs incurred during the test year are representative of the costs the Company will incur on an ongoing basis;[101] (3) the GIS is a mapping database that plays a day-to-day role in the operations of the Company and is utilized extensively by control center personnel through an Outage Management System to operate the system and restore customers in a timely manner when an outage occurs;[102] (4) specific benefits of the GIS program for Rhode Island customers include an increased capability to respond more quickly to customer service requests, improve outage response and restoration times, more accurately communicate outage and restoration information to customers, and reduce the risk to public safety due to the testing of stray voltage on poles;[103] (5) operational enhancements that are not "profit producing" are not susceptible to a "cost-benefit" type analysis because the benefit occurs in the form of upgraded technological capability rather than cost saving efficiencies that may occur, therefore the analysis undertaken by the Company for these types of projects is focused cost control;[104] (6) nearly 97 percent of the costs associated with the New England Overhead GIS Survey in 2008 were for services performed by outside contractors;[105] (7) competitive procurement procedures were used to hire outside contractors to develop the project,[106] and (8) it was more cost effective for the Company to participate in this effort through

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100 Pettigrew Rebuttal Testimony at 21-22.
101 Id.
102 Id. at 22-23.
103 DIV 22-2.
104 DIV 22-2.
105 DIV 17-3; These services involved the collection of field data for overhead electric distribution assets, updating the data in National Grid's GIS, and performing Quality Assurance/Quality Control for field data and data delivered in GIS. Id.
106 Tr. at 154-155 (November 23, 2009).

the Service Company than to undertake the process on its own.[107] As a result, the record evidence presented by the Company does not support the claims made by Division Witness Smith on this issue, i.e., costs are recurring and the costs are reasonably and prudently incurred in order to provide safe and reliable service to customers. Consequently, there is no record support for the disallowance of these costs.

Similarly, there is record support for the disallowance of the costs recorded to Account 588. Division Witness Smith states that a total of $800,000 associated with the Company's electric transformation efforts should be disallowed from Account 588, unless the Company is able to show that (1) there are net benefits for customers, (2) that the program was performed on a "least cost basis" and (3) that the program will cost the same or more on a going forward basis than it did in the test year.[108] However, the Company addressed each one of these elements on the record for the proceeding, which means that there is no basis for exclusion pursuant to Division Witness Smith's recommendation.

Specifically, the Company produced substantial documentation, including a cost-benefit analysis showing that net benefits in the form of reduced O&M and capital expense accrue to the benefit of customers as a result of these expenditures.[109] In addition, Company Witness Pettigrew testified that the transformation program was performed at the lowest cost by following competitive bid processes, using project management skills, tracking all costs and benefits and utilizing a third-party consultant hired through a formal bid process.[110] Lastly, the Company submitted documentation showing that the costs to be incurred on a going-forward

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107 Tr. at 154-155 (November 23, 2009).
108 Smith Direct Testimony at 18.
109 DIV 10-1; DIV 11-32; DIV 17-4, and DIV 22-4.
110 Pettigrew Rebuttal Testimony at 24-25.

basis for the transformation program will be higher than the amount incurred in 2008.[111] As a result, the Company has met the "test" recommended by Division Witness Smith for inclusion of these costs in the revenue requirement, and there is no evidentiary basis for their disallowance.

M. Vegetation Management Expense

The Division is opposing the Company's request for an adjustment to the revenue requirement for increased rate year vegetation management expenses. The Company's initial request of $1,985,000 was subsequently reduced to $1,857,000 based on a reduction to rate year vegetation management expense as per Schedule NG-JP-2 (Revised), filed on November 2, 2009. In contesting the Company's rate year amount, Division Witness Hahn stated that the amount was "speculative" and not "known and measurable" and the Company has not presented adequate justification for the increased spending.[112] However, these claims are not supported by record evidence.

Specifically, Company Witness Pettigrew testified that 60 percent of Rhode Island is covered by forestation and greater than 30 percent of all outages on the overhead distribution system are caused by trees.[113] Company Witness Pettigrew further testified that Rhode Island experiences a four-year growing cycle and the record shows that the Company's vegetation-management costs are primarily driven by the cost of meeting that growth cycle.[114] Company Witness Pettigrew further testified that the Company has made substantial and permanent changes to its vegetation management program and the cost of these permanent work changes is not fully or fairly reflected in the cost of service without the test year adjustment.[115] He also testified that, in 2008, the Company had undertaken an extensive procurement exercise to

111 DIV-10-2; DIV 11-32; DIV 22-4.
112 Hahn Direct Testimony at 9; Hahn Surrebuttal Testimony at 10.
113 Tr. at 96, 136, 138 (November 3, 2009).
114 Tr. at 73-75, 96-97 (November 3, 2009); 114; RR-COMM-8; Schedule NG-JP-2 (Revised).
115 TESTIMONY.

identify qualified, cost-effective contractors, which included the issuance of an RFP and the costs that are included in the test-year adjustment are a function of those contractual costs.[116] Lastly, the Company provided a significant amount of information on the contracts it has recently executed with three outside vendors for vegetation management services, including details on the competitive procurement process undertaken to select these vendors, the scope of their work and the performance metrics that they must meet.[117]

The Division's articulated concern was that the Company's vegetation management costs are not known and measurable and not adequately justified. However, the record shows that the Company's costs are based directly on executed, flat-rate contracts covering a designated amount of work – therefore, the costs are identifiable and accurate.[118] Moreover, the Division has cited no basis for the conclusion that the increased spending is not justified, other than citing to the fact that the Company's SAIDI/SAIFI performance in the test year met the applicable performance benchmark notwithstanding a lower level of spending for vegetation management than proposed in this case.[119] In fact, the Company's SAIDI/SAIFI performance (2006 through 2008) is aligned with the increase in vegetation management spending, which makes sense because vegetation management is the single most cost-effective tool used by the Company to maintain service reliability on system that is primarily overhead.[120] Because the Company has demonstrated that the costs are known and measurable, and because the adjusted test-year cost is representative of the amount of cost the Company will incur in the future, the Commission should allow recovery of this cost through the revenue requirement.

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116 Tr. at 79, 97-98, 142.

117 COMM 7-14; COMM 7-16; DIV 14-1; DIV 14-21; COMM 12-1; COMM 14-1; COMM 14-2; COMM 14-3.

118 Cite.

119 Cite.

120 DIV 11-2 (spending); **Cite for SQI.**

N. Inspection & Maintenance Expense

Similarly, the Division is opposing the Company's request for an adjustment to the revenue requirement of $2,094,000 for increased expense relating to the Inspection and Maintenance Program ("Program"), as well as the Company's proposal to reconcile actual spending to the amount approved in this case on a going forward basis. In recommending against this amount, Division Witness Hahn stated that, although the spending was within the Company's management discretion and can improve reliability and avoid certain outages, the following problems exist with the Company's proposal: (1) the Company has not provided sufficient detail about the inspection plan, (2) the Company has not explained how work performed through the I&M Strategy will differ from what is done now; (3) the potential benefits have not been quantified, (4) the Company has not demonstrated that all of the costs are "truly incremental,"[121] and (5) the amount of the test-year adjustment is "speculative" and not of a sufficient amount to warrant an adjustment in this case, or reconciliation on a going forward basis.[122] However, the Company has addressed each one of these concerns on the record, as follows:

First, contrary to the assertions of Division Witness Hahn, the Company has provided a substantial level of detail regarding the activities that will be conducted through the I&M Strategy. For example, Schedule NG-JP-R-1 is a copy of the Company's I&M Strategy, which provides (1) a description of the strategy; (2) tabular information on the breakdown of asset categories included in the Rhode Island program; (3) detailed lists of the work to be completed for each asset class, including the cycle timing; (4) a detailed explanation of the benefits expected from the program; and (5) a description of implementation issues, risk assessments, and

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121 Hahn Direct Testimony at 7.
122 Hahn Direct Testimony at 7-9; Hahn Surrebuttal Testimony at 10.

other information. A detailed description of the activities to be conducted through the I&M Strategy is also provided in the direct and rebuttal testimony of Company Witness Pettigrew. From an overall perspective, the I&M concept is not complicated nor unique in the electric distribution industry – the program establishes a systematic process and schedule for the inspection and repair of all major distribution assets, so that repairs and replacements can be accomplished on a more cost-effective basis (i.e., as part of a work plan) than possible when inspections, repairs and replacements occur only at such time that performance has degraded to a level that repair or replacement becomes imperative. The testimony submitted by Division Witness Hahn does not address this detailed information in any substantive manner; therefore, his claim that the Company's proposal should be rejected for a lack of detail is not consistent with the record evidence.

Second, the record does not support the Division's assertion that the Company has failed to explain how work performed through the I&M Strategy will differ from what is done now. The record is clear that the Company will aggregate several current programs within the I&M Strategy, and then will expand the scope of the work performed substantially beyond what exists today. Specifically, Company Witness Pettigrew testified that, while the types of asset-management activities conducted by the Company in the past through the Feeder Hardening Program may be the same or similar to the types of activities that will be conducted through the I&M Program, the Company has not conducted those types of activities on the scale or with the systematized schedule that will apply through the I&M Program. In terms of "scale," the Company explained that there will be a significant change in the number inspections that will be performed on a year-to-year basis, meaning that, while the Company has performed inspections on equipment components, such as overhead poles, cross-arms, insulators, transformers and other distribution assets in the past, the Company has generally inspected those components only when a specific reason called for an inspection. The I&M Strategy will involve inspection of the entire system every five years. The record shows that, in order of magnitude, the Company traditionally inspected and maintained 350 miles of the Rhode Island overhead system annually under the Feeder Hardening Program, which going forward would involve the inspection and maintenance of 1,000 miles annually.[123]

Similarly, in terms of "schedule," the Company will make a significant change in the timing of inspections that will be performed on distribution asset; instituting systematic inspection and maintenance of all overhead, underground and sub-transmission line assets on a five-year cycle, with 20 percent of the system completed each year. Prior to the implementation of the I&M Program, systematic inspections were not conducted as part of the Annual Work Plan because work activities, including inspections and maintenance activities, were generally scheduled on a component-by-component basis in response to deficient operating performance or component failure. As a result, distribution assets may not be inspected for long periods of time so long as those components were not exhibiting any performance issues. The testimony submitted by Division Witness Hahn does not address the expanded work scale in any substantive manner; therefore, his claim that the Company's proposal should be rejected for a lack of explanation as to how the program differs from what is done now is consistent with the record evidence.

Third, Division Witness Hahn's assertion that the Company has not provided a cost-benefit analysis is misguided. The record shows that operational enhancements that are not profit producing are not susceptible to a cost-benefit type analysis because the benefit occurs in the form of upgraded technological capability, improved service quality, safety or increased

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[123] Tr. at **[x]** (November 3, 2009).

service reliability rather than cost savings.[124] Schedule NG-JP-R-1 describes the service quality, reliability and safety benefits resulting from implementation of the I&M Strategy.[125] Aside from simply asserting that a cost-benefit analysis should be performed, Division Witness Hahn does not address this issue in a substantive manner.

Fourth, contrary to assertions by Division Witness Hahn, the Company has demonstrated that the costs associated with the I&M Strategy are "truly incremental." As Company Witness Pettigrew testified, the definition espoused by Division Witness Hahn seems to be that incremental costs do not exist going forward so long as the Company incurred some level of cost in the test year for activities that may be undertaken through the I&M Program. However, the *number* of inspection and maintenance activities that will be undertaken through the I&M Program through the rate year are incremental to the number of activities performed in the test year and differ from the test year in substantial amount. Therefore, while the test-year spending amounts include spending through the Feeder Hardening Program, as well as the cost of other activities undertaken to maintain the system, it does not include the cost of the full scale and scope of activities that will occur through the I&M program. Division Witness Hahn has not addressed the cost recovery issue in relation to the cost of incremental work that will be performed.

This point is significant because Division Witness Hahn lastly asserts that the rate-year cost that the Company proposes to include in the cost of service are speculative and not significant enough to warrant a post test year change. However, the Company has derived the cost based on known costs for specific activities multiplied by the number of activities to be

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124 DIV 22-4.

125 Schedule NG-JP-R-1 at page 8 of 17.

performed in the annual work plan. This calculation is not speculative in nature, nor does Division Witness Hahn address this calculation in any manner.

Nor is there any ratemaking standard that would preclude a post test year change based simply on the magnitude of the cost change, as implied by Division Witness Hahn. By adjusting the test-year amount of I&M expense by $2,094,000, the Company is effectively seeking to normalize the cost of the I&M Strategy for inclusion in rates to the level needed to fully implement the program on a five-year cycle. This magnitude in cost change is *greater than* cost changes sought by Division Witness Effron in normalizing storm expense ($1,395,000). As a result, the assertion that the I&M cost change is not of sufficient magnitude for a post test-year change to the cost of service is not consistent with the Division's own testimony. The Division emphasized that implementation of the I&M Strategy is within management discretion and will involve activities that should improve service reliability; the rate-year costs are derived consistent with a specified work plan and known costs, and the proposed cost change is consistent with accepted ratemaking practice. As a result, the Division has not offered any sound basis for rejection of this cost. Accordingly, the Commission should support the Company in its efforts to institute a long-range operating strategy that will benefit customers through service reliability and cost-effective repair and replacement.

O. Credit Collections Expense

The Division is opposing the Company's adjustment of $376,000 for increased credit and collection activities on the basis that "the efforts should pay for themselves" to the extent that write-offs are reduced.[126] However, there is an inherent conflict in the Division's positions in this case, which first reduces the bad-debt ratio (and related expense) on the theory that the

[126] Effron Direct Testimony at 10.

Company should be more aggressive in making calls and collection visits and then disallows the costs associated with those activities. The Division does not claim that the cost calculation is inaccurate; that the costs are unreasonable or that the costs will not be incurred on a going forward basis. The Division's only claim is that there will be a benefit of increased collections and reduced bad debt as a result of these expenditures, which is not a basis for inclusion or exclusion from the cost of service. The Company is allowed to recover costs that it incurs to provide utility service and is not limited to recovery of only those costs that provide no benefit to the overall system; in fact, this would be an absurd ratemaking result. Accordingly, the Commission should allow this expense in rates.

P. Customer Advocacy Expense

The Division is opposing the Company's adjustment of $182,000 plus related taxes for the addition of two consumer advocates on the basis that the Company has not demonstrated that these employees are necessary or appropriate.[127] However, contrary to the assertions of the Division, the Company has demonstrated in this proceeding that this minimal level of cost will produce important benefits for low-income consumers and has proved to be a successful program in the Company's other jurisdictions.[128]

Q. Legal Expense

The Division is requesting the disallowance of $419,000 in legal expense associated with a litigation matter in federal court between Narragansett Electric and Constellation Energy Commodities Group, Inc ("Constellation"), on the basis that the cost of the proceeding included

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127 Effron Direct Testimony at 8-9.
128 RR-COMM-35.

in the test year is not recurring.[129] The Company strongly objects to the disallowance of these costs on substantive and policy grounds.

First, from a policy perspective, the legal costs were incurred to defend against claims by Constellation that would have resulted in significant costs to National Grid's customers in Rhode Island. As stated in the Commission's Order No. 19466 in Docket 3969, at page 3 (October 2008), the evidentiary record in that case showed that the potential liability for customers ranged from $296 million to $400 million. The settlement arrangement approved by the Commission Docket 3969 was made possible by the Company's vigorous defense and resulted in the payment of a substantially lower amount. Ultimately, the savings to customers associated with the successful defense against Constellation's claims far outweighed the relatively moderate legal costs incurred by the Company for outside representation by Hinckley Allen & Snyder ("Hinckley Allen").

Second, in terms of legal costs, the Company originally indicated that $592,946.20 was paid to Hinckley Allen in 2008 (listed in response to COMM-1-93), of which approximately $419,000 related to the Constellation matter. With additional research, the Company determined that the amount paid to Hinckley Allen in 2008 in relation to the Constellation matter was $289,329, rather than $419,000. The difference between the total amount paid to Hinckley Allen of $592,946 and the amount related to the Constellation matter of $289,329, or $303,617, related to several smaller matters.

Thus, the legal costs incurred to defend against the Constellation claims were not significant as compared to total legal costs in any particular year, including 2008. The Company began incurring costs associated with the Constellation matter in 2006, with the bulk of the cost occurring in 2007 and 2008. Since the acquisition of the Rhode Island assets of the New

[129] RR-COMM-20.

England Gas Company and the subsequent merger with KeySpan, the Company has necessarily made greater use of outside counsel to address the increased legal requirements of the larger company. As a result, the Constellation matter represented a relatively small portion of the overall legal expense: or, 9.88 percent in 2006, 13.19 percent in 2007, and 16.47 percent in 2008, and therefore, is simply part of the ebb and flow of costs that the Company will experience from year to year as completed matters are replaced with new matters. Therefore, there is no basis for excluding this litigation cost – the costs were incurred to defend the interests of customers and the costs are not of a magnitude to justify arbitrary removal from the cost of service. In fact, if the completion of an individual case is a reason to disallow the cost of a case, the Company would be unable to justify any level of legal costs, which is an absurd result, but the logical outcome of the Division's recommendation.

R. Rate Case Expense and Amortization

In the Company's initial filing in this proceeding, the Company provided a schedule of estimated rate-case expenses, which totaled $1,730,000.[130] The Company proposed a two-year amortization of these costs in rates with the annual amortized amount incorporated in the revenue requirement totaling approximately $865,000.[131] In response to Data Request COMM-12-13, the Company indicated that its updated cost estimate was $2,176,717, or $1,088,358 for revenue requirement purposes if amortized over two years. The Division is recommending a five-year amortization.[132]

The Company has two points to make on this issue: First, the Company proposes that the Commission allow the Company to finalize rate-case expenses as part of the compliance filing so that the Company's updated and final expenses may be included and so that the Division's

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130 Exh. NG-RLO-2, at page 18.

131 Id.

132 Exh. EFFRON DIRECT at 9--10; EFFRON SURREBUTTAL at 3.

expenses, which are not yet available to the Company, may be included. Second, the Company requests that the Commission allow for a three-year amortization of rate-case expense, which is the same amortization period allowed for the Company's gas operations in Docket 3943. Although the Company believes that a two-year amortization period is more reflective of the likelihood that the Company will experience more frequent cases to fund infrastructure investments and economic pressures on operating expenses, the three-year amortization period is reasonable resolution to the issue in dispute since the Division's recommendation of five years is based solely on the fact that the Company has not had a distribution rate case since the 1990s,[133] which completely ignores the fact that the Company has been subject to long-term rate plans and rate freezes in the intervening time period.

S. Economic Development Expense

The Division opposes the inclusion of $1 million in the revenue requirement for the Company's proposed economic development program. The record shows that utilities are recognized as effective and appropriate economic development partners by the large number of utilities who provide these services. There are currently some 65 investor-owned utilities that participate in the Utility Economic Development Association, covering a large portion of the U.S. and parts of Canada.[134] The Company believes that an economic development program would benefit Rhode Island customers, which include commercial and industrial interests that may be struggling in this economy. That said, the Company views the implementation of this program as a policy determination for the Commission rather than a ratemaking dispute with the Division.

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133 EFFRON SURREBUTTAL at 3.
134 COMM 16-3.

IV. PROPOSED RECONCILIATION FACTORS

A. Introduction

In this case, the Company is proposing the following reconciliation factors: (1) the Standard Offer Adjustment Provision (commodity-related bad debt recovery); (2) the Distribution Adjustment Provision (distribution-related bad-debt recovery); (3) the Pension/OPEB Adjustment Provision; (4) the Revenue Decoupling Mechanism, and (5) the Inspection and Maintenance Cost Adjustment Provision (the "I&M Adjustment").[135] The I&M Adjustment is discussed above in Section III.L and the Company's Revenue Decoupling Mechanism is discussed below in Section V. There is no dispute in this case over the implementation of the Pension/OPEB Adjustment Provision, and therefore, the Company will not address that provision in this brief. Therefore, in this section, the Company will address its proposals for distribution and commodity-related bad debt recovery.

B. Uncollectible Expense Recovery

The Company has made proposals for the recovery of distribution-related bad-debt recovery and commodity-related bad-debt recovery.

For *distribution-related* bad-debt recovery, the Company proposes to calculate the expense level recoverable through base rates using a two-year average of actual write-off experience of 1.10 percent.[136] The Company is further proposing that, if actual expense in the future exceeds the amount included in base rates by greater than $500,000, the Company would be eligible to apply to Commission for recovery of the actual amount in excess of the amount included in rates if certain circumstances are satisfied. Those circumstances would include a showing that: (1) the Company has made 510,000 outbound calls and 41,000 field visits; and

135 COMM 6-1.
136 O'Brien Direct Testimony at 11.

(2) the increase is due to factors beyond its control, such as regulatory, judicial, or legislative changes; market forces beyond the Company's control, including elevated levels of Standard Offer Service rates , elevated and sustained unemployment rates, or a change in public policy directives affective collection practices.[137] The Company believes that this is a reasonable proposal given that Commission ratemaking practice allows recovery of distribution-related bad-debt expense through base rates, and additional recovery is not possible without (1) a showing of cause and response by the Company, and (2) further Commission review and approval. As a result, adopting this proposal does not allow cost recovery above the amount included in base rates in accordance with Commission precedent, unless the circumstances warrant after Commission review and approval.

For *commodity-related* bad-debt recovery, the Company is proposing to transfer recovery from base rates to the Standard Offer Service rate (along with recovery of certain administrative costs relating to commodity service).[138] Under the Company's proposal, the amount allowed for bad-debt recovery through the SOS rate would be the actual amount of commodity-related bad-debt expense incurred by the Company each year.[139] The Division is not contesting the transfer of commodity-related bad debt from distribution rates to the SOS rate. However, as opposed to the fully reconciling mechanism proposed by the Company, the Division is proposing that the Commission institute a bad-debt recovery mechanism similar to that adopted for the Company's gas operations, which allows recovery in an annual amount equal to the bad-debt ratio set by the Commission in this case multiplied by the amount of annual commodity revenues.

Although the Division's proposed mechanism could be workable, it would have to be based on a legitimate uncollectible ratio, which would fairly provide cost recovery over time for

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137 Wynter Direct Testimony at 14-20.
138 Id. at 10-14.
139 Id.

commodity-related bad debt. The Company vigorously objects to the Division's recommendation that the Commission set the allowed bad-debt ratio at 0.71 percent, as calculated by Division Witness Gay, rather than using a an average of the Company's actual bad-debt ratio (five years for the gas company). The Company's concern arises from the fact that there are significant flaws in the analysis presented by Division Witness Gay, which the Company would summarize as follows:

1. *Division Witness Gay overestimates the Company's influence over the rate of uncollectible accounts by substantially discounting the effect of commodity costs and other factors on a customer's ability to pay*. For example, Division Witness Gay states in his direct testimony that "it does not appear that recent increases in commodity prices are the primary factor in the increases in uncollectible expense."[140] Putting all else aside, the conclusion defies logic in that (a) commodity costs account for two-thirds of the customer's bill, and (b) his testimony on the Company's accounts receivable states that "the larger the balance due, the more difficult it is for the typical customer to pay."[141] Moreover, his alleged support for the conclusion that, *over the last two and one-half years,* the Company's average monthly bills and average charge-off balances for customer accounts did not increase or decrease in lockstep with changes in commodity prices.[142] A significant flaw in this claim is that Division Witness Gay evaluated average monthly bills and average charge-off balances for customer accounts in the period January 2007 through February 2009, which is a period that excludes a significant ramp-up in standard offer rates occurring between 2005 and 2006.[143] In fact, the record shows that the significant ramp-up in standard offer rates coincided with an increase in the commodity charge-

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140 Gay Direct Testimony at 7.
141 Id. at 10, lns. 24-25.
142 Gay Surrebuttal Testimony at 4, lns. 11-16 (emphasis added).
143 Schedule NG-RLW-2; Tr. at 53-54 (December 1, 2009).

off rate from 0.66 percent to 1.05 percent, which is the single-greatest increase in the bad-debt ratio occurring over the five-year period 2004 through 2008 (and by comparison the change in the bad-debt ratio from 2006 to 2008 is flat).[144] Therefore it is evident that, by excluding the period prior to 2007 from his analysis, Division Witness Gay has skewed the analysis so that he is comparing standard offer rates to average charge-offs in a period where both components are relatively flat.

This point was highlighted at the evidentiary hearing presenting the testimony of Division Witness Gay. For example, Division Witness Gay conceded that the change in standard offer rates increased by 100 percent in the period May 2003 through February 2009 (i.e., $0.45 cents per kWh to $0.9 cents per kWh), which is not reflected on his Attachment 1 because he has excluded data for the period prior to 2007.[145] Division Witness Gay also stated that he evaluated the relationship between commodity prices and charge-off rates by examining the impact of price increases on monthly customer bills.[146] However, he compared the change in commodity prices to the change in the average customer bill in the months of May 2007, 2008 and 2009, which showed only a three percent change in the average bill from year to year (because electricity usage is relatively flat year-to-year in May).[147] Division Witness Gay conceded that, had he performed the same comparison for August 2007 and 2008, which is a month of relatively high electricity usage, the change in the average bill from 2007 to 2008 would be approximately 40 percent, not three percent.[148] As a result, it is clear that his analysis is flawed: by choosing a month of relatively flat electricity usage, customer bills did not reflect changes in commodity

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144 Schedule NG-RLW-1, page 1 of 2; Tr. at 56 (December 1, 2009).
145 Tr. at 61 (December 1, 2009).
146 Gay Direct Testimony at 7, lns. 21-24.
147 Tr, at 63-64, 68 (December 1, 2009).
148 Id. at 68.

prices that would be evident in periods of higher customer usage. Accordingly, no credence can be given to this analysis.

2. *Division Witness Gay's assertion that the Company's actions are the driving factor in the charge-off rate experience, and not commodity prices or other factors, is not based on any evaluation of a customer's ability to pay*. In making his claim that the Company's actions are the primary driver of bad-debt cost, Division Witness Gas conducted no study or analysis of the factors affecting customer ability to pay. For example, Division Witness Gay conceded that he had no idea of whether the average income of Rhode Island workers had grown since 2003, or whether increases (if any) matched the 100 percent increase in commodity costs.[149] He also conceded that, "if prices of anything increase, there is a certain percentage of customers that are going to have more difficulty in paying their bills."[150] He testified that he did not evaluate income, rates of income increases or discretionary income, economic type data nationwide or in the State of Rhode Island in considering the impact of rising commodity rates on charge-off rates (i.e. a customer's ability to pay).[151] When asked about the impact of significant increases in other household products and services such as food, gasoline, natural gas heating bills, he testified that "when one or other or many of those obligations increase on a monthly or yearly basis, it becomes more difficult for many customers, for many persons or many households and businesses to pay those bills."[152] Lastly, he testified that he did not have any knowledge of the Rhode Island unemployment rate, although he would not dispute the statement that job loss is likely to affect a customer's ability to pay their electric bill.[153] Accordingly, the claims made by Division Witness Gay that the Company's management of "its delinquent portfolio of accounts

149 Id. at 68.
150 Id. at 72-73.
151 Id. at 73-74.
152 Tr. at 74-75 (December 1, 2009).
153 Id. at 75.

receivable" is the driving factor in the charge-off rate is not substantiated by any valid research or information regarding a customer's ability to pay, or how the ability to pay affects the charge-off rate. Accordingly, these contentions should be disregarded by the Commission.[154]

2. *Mr. Gay's assertion that the Company under-performed on the collection of revenues is based on faulty analysis that is overly dependent on calculations of "average" impacts and that presents a distorted view of the actual facts as known to the Company in conducting collection operations.* The testimony presented by Division Witness Gay is centered squarely on the allegation that the Company under-performed in 2008 in managing its accounts receivable, which is attempts to substantiate with a series of tables from beginning to end of his testimony. These tables present a picture of the Company's receivable accounts that is derived through layers of averaging calculations, which have the effect of significantly distorting the facts regarding the status of the Company's accounts receivables. In the end result, his recommended reduction in the charge-off rate is based on a gross over-simplification of accounts, which is not supported by any consideration of customer-specific circumstances. Two critical examples of this effect are as follows:

First, in attempting to analyze the Company's "Accounts Receivables versus Performance" for non-residential customers, Division Witness Gay calculated an average balance per account in April 2008 of $3,173 for the "delinquent portfolio" (or $25,650,420 divided by 8,083 non-residential customers who are "eligible for disconnect").[155] However, to calculate this average, he included all amounts less than 60 days due, including current bills.[156] If the total amount *over 60 days due* was divided by the 8,083 non-residential customers eligible

154 Gay Direct Testimony at 10.
155 Exh. GAY DIRECT at 13 (table on lines 11-12).
156 Tr. at 109 (December 1, 2009).

for disconnect, the “delinquent” balance shown would be $792 per customer.[157] This is important because represents in the same chart that the Company has only shut off 78 customers with average balances of $997, which makes it appear that the Company’s “delinquent portfolio” included a slew of customers who were not shutoff, despite having an account balance of $3,173. Once the math is corrected to exclude current bills, it is clear that the Company shut off 78 customers with an average balance of $997, and that the average delinquent balance for these 8,083 customers was *less than that amount*, or only $792, which is highly susceptible to collection through normal protocols rather than the more severe shut-off alternative. Also, it should be noted that the figure of 78 disconnects *is for one month of the year*, and therefore, is not comparable to the delinquent balance amount, which arises over multiple months.

Similarly, in attempting to analyze the Company’s “Accounts Receivables versus Performance” for residential customers, Division Witness Gay calculated an average “delinquent balance” per account in April 2008 of $673 (or $34,595,574 divided by 51,395 non-residential customers).[158] However, to calculate this average, he included all amounts less than 60 days due, including current bills.[159] If the total amount *over 60 days due* was divided by the 51,395 residential customers eligible for disconnect, the arrearage balance shown would be $282 per customer.[160] As with non-residential accounts, this point is important because he represents in the same chart that the Company has only shut off 934 customers with average balances of $587.[161]. Since his measurement of the Company’s performance is to compare the average delinquent balance with the average balance on accounts that were disconnected,[162] this faulty

157 Tr. at 113 (December 1, 2009)
158 Gay Direct Testimony at 13 (tables on lines 11-12); Gay Direct Testimony at 16.
159 Tr. at 126 (December 1, 2009).
160 Tr. at 126 (December 1, 2009).
161 Gay Direct Testimony at 17, (see table for #of disconnections).
162 See, e.g., Gay Direct Testimony at 15 (lns 1-5); page 18 (at lns. 10-14).

calculation makes it appear that numbers of customers were not shut off with an account balance of $673 or more. Once the math is corrected to exclude current bills, it is clear that the Company shut off 934 customers with an average balance of $587, and that the average overdue balance for these 51,395 customers was *less than that amount*, or only $282. As with the non-residential accounts, it is important to note that the figure of 934 disconnects *is for one month of the year*, and therefore, is not comparable to the "delinquent" amount, which is a multi-month amount.

There are equally faulty assumptions underlying his final recommendation. For example, in calculating his recommended charge-off rate of 0.71 percent, Division Witness Gay reduces actual net write-offs in 2008 for *non-residential* customers ($2,788,025) by **$1,246,140** (or **258** accounts X **$805** average bill X **6** months).[163] However, he conceded that: (a) the 258 accounts included in his calculation were "voluntarily terminated," meaning that the accounts have requested a service termination and *may not have had any arrearage balance*, having only defaulted on a current bill issued after their termination;[164] (b) he did not check specific account level history or payment history on an individual account basis for these 258 customers;[165] (c) he disregarded the fact that voluntarily terminated accounts may not have had any arrearage balances, because the average account balance of *the non-residential group* was $8,200 and its "not likely that any of the [voluntarily terminated] customers had an $8,000 current bill";[166] (d) although, he then testified that of the Company's 1,034 non-residential accounts (encompassing the 258 voluntarily terminated customers), 246 accounts had arrearage balances of less than $25 (which may have pertained disproportionately to the 258 voluntarily terminated

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[163] Gay Direct Testimony at 25, fn.5 (the text set forth in footnote 6 should have been contained in footnote 5, relating to non-residential customers rather than protected customers)(Tr. at 97-98).

[164] Gay Direct Testimony at 24, lns. 18-19; page 24 (footnote 5); Tr. at 90 (December 1, 2009).

[165] Tr. at 94 (December 1, 2009).

[166] Tr. at 90-91 (December 1, 2009).

customers);[167] (e) he then testified that the highest balance in the non-residential group was $559,000, which along with other large accounts would have the direct effect of skewing the average non-residential customer balance to the artificially high level of $8,200.[168] Because he did not ascertain whether any of the 258 voluntarily terminated accounts had arrearage balances; because there were 246 customers in the non-residential group that had arrearage balances less than $25 and could have largely represented voluntarily terminated customers; because he has no specific information that these 258 accounts had arrearages of up to six months even if arrearages existed, and because his assumption regarding the $8,200 average monthly bill is skewed upward by the inclusion of substantial arrearage balances, his conclusion that the Company's 2008 non-residential writeoffs could have been reduced by $1,246,140 as a result of better accounts receivable management is completely without merit and should be rejected by the Commission.

Similarly, his recommendation on the exclusion of charge-offs for the residential class suffers from the same fatal flaws as the non-residential analysis. Specifically, in calculating his recommended charge-off rate of 0.71 percent, Division Witness Gay reduces actual net write-offs in 2008 for residential customers ($8,747,620) by **$3,618,136** (calculated as **5449** accounts X **$83** average bill X **8** months).[169] However, he conceded that: (a) the average bill amount of $83 was computed by dividing the number of residential bills into residential sales revenue for each month and then averaging the resulting (12) monthly amounts (i.e, this amount is not the actual average bill amount for the 5,449 customers included in the calculation and he has not

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167 Tr. at 91-92 (December 1, 2009).

168 Tr. at 92 (December 1, 2009).

169 Gay Direct Testimony at 25, fn.5 (the text set forth in footnote 6 should have been contained in footnote 5, relating to non-residential customers rather than protected customers)(Tr. at 97-98).

validated the reasonableness of the assumed $83 amount with real data);[170] (b) the group of 5,449 customers he has included in the calculation includes 2,138 customers that he claims have account balances greater than 13 months. However, this alleged 13-month period is derived by dividing an average balance per account of $1,196 by the $83 proxy for the average monthly bill and subtracting 30 days (i.e., the 13-month period is not based on actual arrearage time periods, nor is validated by comparison to actual periods);[171] (c) the group of 5,449 customers also includes 3,311 accounts that voluntarily terminated and according to his averaging routine had an average balance per account of $1,181, and a past due period calculated as greater than 13 months;[172](d) however, as with the non-residential accounts, Division Witness Gay did not examine the circumstances of the individual accounts and did not determine whether the voluntarily terminated accounts *had any arrearage balance at all*, or if an arrearage balance existed whether it was more than 30-60 days in duration, which is not generally the case with a voluntarily terminated account. Given the overlapping averaging calculations, and the fact that all of his conclusions regarding the Company's performance were based on an inaccurate calculation including current bill amounts, and the fact that he has based this adjustment on voluntarily terminated accounts, there is no validity to his calculations. Accordingly, there is no validity to his claim that a total of by $3,618,136 in charge-offs should be excluded from the Company's actual 2008 charge-off amounts and the Commission should reject this claim.

3. *Mr. Gay's calculation of the bad-debt ratio of 0.71 percent is based on an assumption that the Company should be shutting off all residential customers with arrearages greater than 150 days and all commercial and industrial customers with arrearages greater than 90 days, regardless of the circumstances of the account.* The essence of the recommendation

170 Tr. at 70-71 (December 1, 2009).
171 Gay Direct Testimony at 15, lns. 13-15, fn. 4.
172 Gay Direct Testimony at 15, lns. 21-23.

made by Division Witness Gay is that the Commission should establish a charge-off ratio for ratemaking purposes, which is based on the assumption that residential customers with arrearage balances should be shut off after 150 days and non-residential customers with arrearage balance should be shut off after 90 days, regardless of the customer's circumstances. This proposition defies all common sense given that the Commission's regulations impose the obligation to handle customer accounts on an individualized basis with attention paid to customer circumstances, credit quality and payment history or willingness to commit to a payment plan, even if that plan is ultimately broken. In addition, the charge-off rate of 0.71 percent is well on the low side of the Company's experience since 2004 and well below the annual rate or five-year average of other utilities in New England that recover bad-debt expense in a comparable manner.[173] Moreover, Division Witness Gay testified that current economic conditions are likely having a negative effect on the charge-off rate as this proceeding is occurring.[174] Therefore, the only result of a Commission decision to impose a 0.71 charge-off rate for ratemaking purposes is to (1) deny the Company recovery of a reasonable level of bad-debt cost for no valid reason; and (2) strongly encourage the Company to ramp-up service disconnects to unprecedented levels, which is not a desirable result for the Company or its customers.

C. Transmission-Related Uncollectible Expense

In this case, the Company and the Division are in agreement that it would be appropriate for the Company to recover transmission-related uncollectible expense through the transmission rate that is set by the Commission to recover Narragansett Electric's transmission costs. However, it appears to the Company that the Division is asserting that recovery of transmission-related uncollectible expense should be denied in this case and set aside until some point in the

173 Schedule NG-RLW-1; RR-COMM-41.
174 Gay Direct Testimony at 9.

future when transmission rates may be reset for some other reason.[175] However, as with the Standard Offer Service charge, it is wholly within the Commission's discretion and authority to change the retail transmission rate to include recovery of transmission-related bad debt costs. Conversely, there is no valid reason for the Commission to defer recovery of transmission-related uncollectible expense to some future date.

On cross-examination, Division Witness Effron agreed that the Federal Energy Regulatory Commission ("FERC") sets the transmission rates to be charged by New England Power Company)"NEP") to all of its wholesale transmission customers, including Narragansett Electric and that NEP does not serve any retail customers.[176] Division Witness Effron further agreed that, in setting rates for NEP, FERC's scope of review would be the costs incurred by NEP and not the costs incurred by Narragansett Company to provide transmission services to retail customers.[177] Division Witness Effron also agreed that, to the extent that Narragansett Electric passes on its wholesale transmission costs to retail customers, it would be through a rate approved by the Commission.[178] Lastly, Division Witness Effron testified that he "can't think of any reason why it wouldn't be appropriate" for the Commission to provide for recovery of transmission-related uncollectible expense through retail transmission rates in this case.[179] Accordingly, the Commission should transfer recovery of transmission-related uncollectible expense from base distribution rates to the retail transmission rate in this proceeding.

V. REVENUE DECOUPLING RATEMAKING PLAN

In this proceeding, the Company has proposed to implement a revenue decoupling mechanism ("RDM" to facilitate the recovery of the revenue requirement approved by the

175 Effron Surrebuttal Testimony at 4.
176 Tr. at 188-190 (November 5, 2009).
177 Tr. at 189-190 (November 5, 2009).
178 Tr. at 191 (November 5, 2009).
179 Tr. at 193 (November 5, 2009).

Commission in this case. The RDM is one part of a Revenue Decoupling Ratemaking Plan (the "RDR Plan"), which encompasses (1) the RDM in order to reconcile billed revenue to the annual revenue target, or "ATR," set by the Commission (i.e., the allowed revenue requirement, unless other adjustments are allowed); and (2) other "cost-side" adjustments to account for the effects of inflation beyond those reflected in the rate case and cumulative net capital spending (above amounts supported in base rates) based on actual recent levels of capital additions made by the Company.[180]

There are volumes of information contained in the record regarding the purpose and effect of revenue decoupling and the RDR Plan in its entirety. However, at bottom, the RDM is designed to accomplish two main objectives, which are: (1) to neutralize the impact of sales loss attributable to the Company's energy efficiency programs, as well as systematic conservation efforts occurring throughout the economy, and (2) to provide a level of stability in the Company's revenues so that it can adequately manage operations with the need for frequent rate cases. The record shows that the RDM is entirely severable from the RDR Plan, and could be implemented by the Commission without allowing for the remaining recommendations.[181]

In that regard, there are two main points that the Company would like to make in relation to the RDM. First, Schedule NG-APM-1 (page 1 of 1) shows that, excluding any increase in energy efficiency savings, the Company experienced a relatively long trend of increasing sales growth in the 10-year period 1996 through 2005, with residential sales growth of 0.5% to over 4% occurring in every year except 1997 (by -0.3%) and 2000 (by -1.0%), and commercial sales growth of 1% to 4% occurring in every single year. By contrast, the Company experienced declining sales growth for both residential and commercial customers in two out of three years in

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180 Tr. at 9 (December 9, 2009); Tierney Direct Testimony.

181 Tr. November 4, 2009.

the period 2006 through 2008. Although the industrial growth rate exhibited several more years of negative sales growth, the declines in 2006 through 2008 are greater than any other year. The Company cannot recover its costs through rates if the customer consumption used to calculate those rates is declining.

Second, it is important to note that the Company has presented detailed information in this case demonstrating that the impact of the RDM mechanism is likely to be relatively small, excluding the cost side adjustments. On that point, the Company submitted the results of study, authored by Ms.Pamela Lesh for the Regulatory Assistance Project ("Lesh Report"). The Lesh Report is a comprehensive assessment of revenue decoupling mechanisms adopted by state commissions and utilities around the country. Based on the author's review of all revenue decoupling mechanisms in operation in the U.S., she concludes that "Decoupling adjustments tend to be small, even miniscule. Compared to total residential retail rates, including gas commodity and variable electricity costs, decoupling adjustments have been most often under two percent, positive or negative, with the majority under 1 percent.[fn] Using Energy Information Administration (EIA) data for 2007 on gas and electric consumption per customer and average rates, this amounts to less than $1.50 per month in higher or lower charges for residential gas customers and less than $2.00 per month in higher or lower charges for residential electric customers."[182] The Company also submitted detailed analysis on the anticipated rate impacts of the RDM in response to Division Data Request DIV 6-19 (f).

VI. RATE DESIGN ISSUES

The Company has proposed a rate design to recover the allowed revenue requirement and that adheres to the following principles: (1) to reflect the results of the allocated cost-of-service study as closely as possible; (2) to promote the efficient use of resources, ultimately resulting in

182 Tierney Rebuttal Testimony at 28.

lower bills to customers; (3) to produce rates for customers and revenues for the Company that are reasonably stable and predictable while reflecting the nature of the costs they are designed to recover; and (3) to mitigate against extreme rate impacts on customer subgroups. Based on these principles, the Company proposes the following:

- A Minimum System Study should not be required from Company in next base rate case; investment in distribution line costs are appropriately classified in Accts 364 and 368 on a demand basis.
- Direct assignment of investment in transformer costs in Acct. 368 to rate classes based on a study of customers served by each transformer (direct position) is appropriate.
- Delivery-related uncollectible expense should be allocated (1) to classes where costs originate, or (2) to all classes on basis of (test year) Total Delivery Revenues, or (3) all classes on the basis of rate year delivery revenue.
- SOS-related administrative costs should be allocated to classes where costs originate resulting in $6.6M allocated to the Small Customer Group and the remaining costs allocated on equal basis from the Small Customer Group and the Large Customer Group
- Commodity-related Cash Working Capital should be allocated on the basis of Commodity Revenue.
- $5.4 million in Customer Information & Services expenses (Accounts 907 and 913) should be allocated based on the number of customers.
- Shortfall arising from cap on Lighting & Propulsion classes should be allocated exclusively to C&I Large Demand Class.
- Economic development costs should be recovered from C&I customers based on kWh deliveries.
- Rate A-60 should receive its proportionate share of the residential increase.
- C&I Large Demand Class should first be brought to its cost of service before allocating Commission adjustments to other rate classes
- Low-income subsidy should be recovered from all customer rate classes.
- Allocation of transmission costs should be based on coincident peak and, if so, that this allocation be performed annually as part of the Company's annual retail rate filing.
- Elimination of G-62/B-62 rate class should be allowed.
- If revenue decoupling is approved, Commission should consider whether back-up rates should be eliminated.
- The Company's proposed customer charges should be approved.

Proposed Commission Findings on Rate Design

1. The Commission finds that the Company's proposed rate design is in the public interest and approved.

2. The Company shall file 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 March 1, 2010, as adjusted by the Commission's earlier order regarding the extension of time to consider the Company's application.

Respectfully submitted,

NATIONAL GRID

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Dated: January 22, 2010

The Narragansett Electric Company d/b/a National Grid
Comparative And Updated Revenue Requirement
For the Twelve Months Ended December 31, 2010

Changes From Schedule NG-RLO-R-1 as Filed (Rebuttal Filing)
($ in Thousands)

Line #	Description	Reference Or Factor	Amount on As Filed Schedule	Revised Amount	Change	Discussion	Notes
	(a)	(b)	(c)	(d)	(e)	(f)	
1	The following adjustments are required to Schedule NG-RLO-R-1 to reflect impacts on the accounts noted in column (a) which were not included in the original Schedule as filed.						
2	**Revenue Deficiency as filed in Company's Rebuttal (Schedule NG-RLO-R-1):**				**$63,586**		
3	Adjustments filed in Division Data Request 27-1:						
4	*Rate Base:*						
5	Cash Working Capital	Pg 2, C (d), L 11	($338)	($324)	$14	True Up to CWC amount shown in Updated Schedule NG-RLO-2	1/
6	Times Weighted Cost of Capital				8.98%		
7	Cost of Service Change Due to Rate Base				$1		
8	*Expenses:*						
9	Uncollectible Expense	Pg 3, C (d), L 23	$0	($25)	($25)	Impact of Changes in Uncollectibles from Net Revenue Increase change	1/
10	Facilities Rent	Pg 3, C (d), L 25	($46)	($44)	$2	Impact of IFA on change	1/
11	Other O & M Expense	Pg 3, C (d), L 28	$0	$4	$4	Impact of Inflation on other adjustments	1/
12	Load Response Credit	Pg 3, C (e), L 20	$0	($300)	($300)	Inclusion of credit recorded in 2009 that should have been included in the test year	1/
13	Cost of Service Change Due to Change in Expenses		($46)	($365)	($319)		
14	**Revenue Deficiency filed in Division Data Request 27-1:**	Page 1, C (h), L 27			**$63,267**		
15	*Expenses:*						
16	Vegetation Management	Pg 3, C (g), L 12	$8,809	$8,681	($128)	Reduction in Rate Year Vegetation Management Expense	2/
17	Net Synergy Savings - CTA Amortization	Pg 3, C (g), L 21	$2,100	$924	($1,176)	Elimination of CTA for years 1 and 2; 8 year amortization	2/
18	Net Synergy Savings - 50/50 Sharing	Pg 3, C (g), L 22	$3,250	$3,838	$588	Adjustment to Sharing Amount Reflecting Division's Adjustment to CTA Amortization	2/
19	IS Leasing Expense	Pg 3, C (g), L 27	($412)	($583)	($171)	Reduction in Rate Year IS Leasing Expense	2/
20	Rate Case Amortization	Pg 3, C (g), L 9	$865	$726	($139)	Reflects updated rate case costs (Comm 12-13) amortized over 3 years per Company Brief position. Rate case costs to be updated for final Company and Division costs.	2/
21	Uncollectible Expense	Pg 3, C (g), L 23	$0	($12)	($12)	Impact of Changes in Uncollectibles from Net Revenue Increase change	2/
22	Cost of Service Change Due to Change in Expenses		$14,612	$13,574	($1,038)		
23	**Revenue Deficiency filed as Appendix to Initial Brief:**	Page 1, C (h), L 27			**$62,229**		

1/ Adjustments reflected in response to Division Data Request 27-1.
2/ Adjustments reflected as part of Company's Initial Brief.

The Narragansett Electric Company d/b/a National Grid
Comparative And Updated Revenue Requirement
For the Twelve Months Ended December 31, 2010

Cost of Service
($ in Thousands)

Line #	Description	Reference Or Factor	Company As Filed	Division Adjustments	Division As Filed	Company Adjustments: Updates & Corrections	Company Adjustments: Rebuttal	Revised Company Position	Additional Company Adjustments	Revised Company Position for Brief	Division Surrebuttal Position	Difference Company and Division
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
					(a) + (b)			Sum (c) to (e)		(f) + (g)		Sum (I) - (h)
1	Rate Base	Pg 2, L 19	$ 623,949	$ (38,343)	$ 585,606	$ (638)	$ 31,467	$ 616,435	$ -	$ 616,435	$ 583,873	$ (32,562)
2												
3	Weighted Cost of Capital		8.98%	-1.20%	7.78%	0.00%	1.20%	8.98%	0.00%	8.98%	7.54%	-1.44%
4												
5	Return on Rate Base	L 1 * L 3	56,031	(10,493)	45,538	-	379	55,356	-	55,356	44,001	(11,355)
6												
7	Income Tax Expense	P 2, L 40	18,999	(4,366)	14,632	(235)	4,366	18,764	-	18,764	14,589	(4,175)
8												
9	Total Return and Income Taxes	L 5 + L 7	75,029	(14,859)	60,170	(235)	4,745	74,119	-	74,119	58,589	(15,530)
10												
11	Operating Expenses											
12	Operation & Maintenance	P 3, L 26	147,534	(22,184)	125,350	(188)	21,884	147,046	(1,038)	146,008	125,698	(20,310)
13												
14	Depreciation	P 3, L 28	41,466	(688)	40,778	(9)	688	41,457	-	41,457	40,779	(678)
15												
16	Amortization	P 3, L 29	686	-	686	-	-	686	-	686	686	-
17												
18	Taxes Other Than Income Taxes	Pg 3, L 30	24,060	(962)	23,098	(879)	962	23,181	-	23,181	23,102	(79)
19												
20	Total Operating Expenses	Sum L 12 to L 18	213,746	(23,834)	189,912	(1,076)	23,534	212,370	(1,038)	211,332	190,265	(21,067)
21												
22	Total Cost of Service	L 9 + L 20	288,775	(38,693)	250,082	(1,311)	28,279	286,489	(1,038)	285,451	248,855	(36,597)
23												
24	Revenues From Current Rates	P 3, Line 3	223,242	-	223,242	(20)	-	223,222	-	223,222	223,222	-
25												
26												
27	Revenue Deficiency 1/	L 22 - L 24	$ 65,533	$ (38,693)	$ 26,840	$ (1,291)	$ 28,279	$ 63,267	$ (1,038)	$ 62,229	$ 25,633	$ (36,597)

1/ Excludes Commodity-related uncollectibles of $9,751,787.

The Narragansett Electric Company d/b/a National Grid
Comparative And Updated Revenue Requirement
For the Twelve Months Ended December 31, 2010

Rate Base, Return and Taxes
($ in Thousands)

Line #	Description	Reference Or Factor	Company As Filed	Division Adjustments	Division As Filed	Company Adjustments: Updates & Corrections	Company Adjustments: Rebuttal	Revised Company Position	Additional Company Adjustments	Revised Company Position for Brief	Division Surrebuttal Position	Difference Company and Division
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
					(a) + (b)			Sum (c) to (e)		(f) + (g)		Sum (I) - (h)
	RATE BASE											
1	Electric Plant in Service		$ 1,232,747	$ (20,222)	$ 1,212,525	$ (269)	$ 20,222	$ 1,232,478	$ -	$ 1,232,478	$ 1,212,525	$ (19,953)
2	Plant Held for Future Use		204		204			204		204	204	-
3	Contributions in Aid of Construction		(103)		(103)			(103)		(103)	(103)	-
4	Accumulated Depreciation		(516,525)	(2,397)	(518,922)	(66)	2,397	(516,591)		(516,591)	(518,922)	(2,331)
5												
6	Net Plant	Sum L 1 to L 4	716,323	(22,619)	693,704	(335)	22,619	715,988	-	715,988	693,704	(22,284)
7												
8	Materials & Supplies		6,376		6,376			6,376		6,376	6,376	-
9	Prepayments		2		2			2		2	2	-
10	Loss on Reacquired Debt		4,592		4,592			4,592		4,592	4,592	-
11	Cash Working Capital		17,789	(8,848)	8,941	(324)	8,848	17,465		17,465	7,187	(10,278)
12	Sub-Total	Sum L 8 to L 11	28,759	(8,848)	19,911	(324)	8,848	28,435	-	28,435	18,157	(10,278)
13												
14	Accumulated Deferred Income Tax		(113,088)	(6,876)	(119,964)	21		(119,943)		(119,943)	(119,943)	-
15	Customer Deposits		(3,283)		(3,283)			(3,283)		(3,283)	(3,283)	-
16	Injuries & Damages Reserve		(4,762)		(4,762)			(4,762)		(4,762)	(4,762)	-
17	Sub-Total	Sum L 14 to L 16	(121,133)	(6,876)	(128,009)	21	-	(127,988)	-	(127,988)	(127,988)	-
18												
19	RATE BASE	L 6 + L 12 + L 17	$ 623,949	$ (38,343)	$ 585,606	$ (638)	$ 31,467	$ 616,435	$ -	$ 616,435	$ 583,873	$ (32,562)
20												
21	Weighted Cost of Capital		8.98%	-1.20%	7.78%		1.20%	8.98%		8.98%	7.54%	-1.44%
22												
23	After-Tax Return Requirement	L 19 * L 21	56,031	$ (10,494)	45,537			55,356		55,356	44,001	(11,355)
24												
25	Weighted Return on Equity		5.81%		4.81%			5.81%		5.81%	4.81%	-1.00%
26												
27	Equity Return	L 19 * L 25	36,251	(8,107)	28,144			35,815		35,815	28,061	(7,754)
28												
29	Flow Thru Items		(1,269)	-	(1,269)			(1,269)		(1,269)	(1,269)	-
30												
31	Taxable Income Base	L 29 + L 29	$ 34,982	$ (8,107)	$ 26,875			$ 34,546		$ 34,546	$ 26,792	$ (7,754)
32												
33	Taxable Income	L 31 / 0.65	$ 53,819	$ (12,473)	$ 41,346			$ 53,147		$ 53,147	$ 41,219	$ (11,928)
34												
35	Calculated Income Tax	L 33 * 0.35	$ 18,837	$ (4,366)	$ 14,470			$ 18,602		$ 18,602	$ 14,427	$ (4,175)
36	Rounding											
37	Unfunded DIT Catch-Up		650		650			650		650	650	-
38	Amortization of ITC		(488)		(488)			(488)		(488)	(488)	-
39												
40	Total Income Tax Expense	Sum L 35 to L 38	18,999	(4,366)	14,632	(235)	4,366	18,764		18,764	14,589	(4,175)
41												
42	Total Return & Income Taxes	L 27 + L 40	$ 75,029	$ (14,860)	$ 60,169	$ (873)	$ 4,366	$ 74,119		$ 74,119	$ 58,589	$ (15,530)

The Narragansett Electric Company d/b/a National Grid
Comparative And Updated Revenue Requirement
For the Twelve Months Ended December 31, 2010

Operating Revenue and Expenses
($ in Thousands)

Line #	Description	Reference Or Factor	Company As Filed	Division Adjustments	Division As Filed	Company Adjustments: Updates & Corrections	Company Adjustments: Rebuttal	Revised Company Position per DIV 27-1	Additional Company Adjustments	Revised Company Position for Brief	Division Surrebuttal Position 3/	Difference Company and Division
			(a)	(b)	(c) (a) + (b)	(d)	(e)	(f) Sum (c) to (e)	(g)	(h) (f) + (g)	(i)	(j) Sum (I) - (h)
	OPERATING REVENUES											
1	Distribution Revenue		$ 215,543	$ -	$ 215,543	$ -	$ -	$ 215,543	$ -	$ 215,543	$ 215,543	$ -
2	Other Revenue		7,699		7,699	(20)	-	7,679		7,679	7,679	-
3	Total Revenue	L 1 + L 2	$ 223,242	$ -	$ 223,242	$ (20)	$ -	$ 223,222	$ -	$ 223,222	$ 223,222	$ -
4												
5	OPERATING EXPENSES											
6	Salaries & Wages		$ 46,372	$ (1,204)	$ 45,168	$ -	$ 1,204	$ 46,372	$ -	$ 46,372	$ 45,168	$ (1,204)
7	Contracted Minimum Staffing		1,363	(1,363)	-		1,363	1,363		1,363	-	(1,363)
8	Customer Assistance Advocacy		182	(182)	-		182	182		182	-	(182)
9	Rate Case Expense Amortization		865	(519)	346		519	865	(139) 1/	726	435 1/	(291)
10	Customer Contact Activities		376	(376)	-		376	376		376	-	(376)
11	Economic Development Program		1,000	(1,000)	-		1,000	1,000		1,000	-	(1,000)
12	Vegetation Management Program		8,809	(1,985)	6,824		1,985	8,809	(128)	8,681	6,824	(1,857)
13	Inspection & Maintenance Program		4,676	(2,094)	2,582		2,094	4,676		4,676	2,582	(2,094)
14	Affiliate Charge - GIS in a/c # 583		5,315	(2,300)	3,015		2,300	5,315		5,315	3,015	(2,300)
15	Affiliate Charge - Transformation a/c # 588		1,600	(800)	800		800	1,600		1,600	800	(800)
16	Storm Fund Accrual		1,041	(1,041)	-		1,041	1,041		1,041	-	(1,041)
17	Storm Damage Annual		4,932	(2,001)	2,931	(522)	2,001	4,410		4,410	3,015	(1,395)
18	Injuries & Damages		7,055	(2,500)	4,555		2,500	7,055		7,055	4,555	(2,500)
19	Legal Fees		1,756	(419)	1,337		419	1,756		1,756	1,337	(419)
20	ISO Load Research Credit		-	(300)	(300)			(300)		(300)	(300)	-
21	Merger Synergy Savings - CTA Amortization		2,100	(1,176)	924		1,176	2,100	(1,176)	924	924	-
22	Merger Synergy Savings - Savings Sharing		3,250		3,250			3,250	588	3,838	3,250	(588)
23	Uncollectible Expense		5,020	(2,924)	2,096	(25)	2,924	4,995	(12)	4,983	2,087	(2,896)
24	Merger CTA Adjustment		(4,031)		(4,031)	399		(3,632)		(3,632)	(3,632)	-
25	Facilities Rent		554		554	(44)		510		510	510	-
26	IS Leasing Expenses		(412)		(412)			(412)		(412)	(412)	-
27	Incremental Reduction to IS Leasing Expenses								(171) 2/	(171)	(171) 3/	-
28	Other O&M Expense		55,711		55,711	4		55,715		55,715	55,711	(4)
29												
30	Total Operating Expenses	Sum L 6 to L 28	147,534	(22,184)	125,350	(188)	21,884	147,046	(1,038)	146,008	125,698	(20,310)
31												
32	Depreciation		41,466	(688)	40,778	(9)	688	41,457		41,457	40,779	(678)
33	Amortization		686		686			686		686	686	-
34	Taxes Other Than Income Taxes		24,060	(962)	23,098	(879)	962	23,181		23,181	23,102	(79)
35	Operating Expenses Before Income Taxes	Sum L 31 to L 33	213,746	(23,834)	189,912	(1,076)	23,534	212,370	(1,038)	211,332	190,265	(21,067)
36												
37	Income Tax Expense		18,999	(4,366)	14,633	(235)	4,366	18,764		18,764	14,589	(4,175)
38	Total Operating Expenses	L 34 + L 36	$ 232,745	$ (28,200)	$ 204,545	$ (1,311)	$ 27,900	$ 231,134	$ (1,038)	$ 230,096	$ 204,854	$ (25,242)

1/ Company adjustment in column (g) reflects the amortization of the Company's updated estimate of rate case expenses of $2,176,717 as filed in response to Commission Data Request 12-13. Division Surrebuttal Position adjusted to reflect 5 year amortization of total rate case costs from Commission Data Req 12-13. Final amounts to be included upon conclusion of this proceeding. Difference between Company and Division positions reflects the amortization of rate case expenses over 3 years by the Company and 5 years by the Division.

2/ Reflects an incremental reduction by the Company to IS Leasing Costs as filed in response to Commission Data Request 13-7.

3/ Division Surrebuttal position adjusted to include the adjustment to reduce IS Leasing costs as per footnote 2 above.