STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE: APPLICATION OF THE NARRAGANSETT ELECTRIC COMPANY d/b/a NATIONAL GRID FOR APPROVAL OF CHANGE IN ELECTRIC AND GAS BASE DISTRIBUTION RATES — DOCKET NO. 4323

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REPORT AND ORDER

I. Introduction

On April 27, 2012, Narragansett Electric Company, d/b/a National Grid ("National Grid" or "Company") filed for an increase in its electric and gas distribution rates for the rate year ending January 31, 2014.[1] The filing consisted of 11 volumes of testimony which are summarized below. National Grid previously filed an application to increase its electrical rates on June 1, 2009 (Docket 4065). It also filed for an increase in gas distribution rates on April 1, 2008 (Docket 3943). This is the first consolidated rate case filed by the Company in that it addresses both the electric and gas operations of the Company. To promote clarity, and in order to properly distinguish the gas and electric operations of the Company, the following terminology shall apply throughout this Order. The term "Company" shall refer collectively to both the gas and electric operations. The terms Narragansett Electric Company (or Narragansett Electric) and Narragansett Gas Company (or Narragansett Gas) shall refer to either the electric or gas operations of the Company. The Company requested an increase of $31.4M and $19.9M, respectively, to its electric and gas base distribution rates. This request was based on a proposed electric revenue requirement of $270,471,182, a proposed gas revenue requirement of $173,128,689 and return on equity ("ROE") of 10.75%. The proposed revenue requirements were based on the Company's actual capital structure as of December 31, 2011.[2] The monthly electric bill impact associated with the Company's original rate filing was $3.97 for a typical residential customer.[3] The annual gas bill impact for a typical residential heating customer was $98.00.

On October 19, 2012, the Company filed a settlement agreement resolving all of the contested issues among the signatories. The signatories to the settlement agreement were

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[1] The effective date of the proposed rate increase is February 1, 2013.

[2] The Company's capital structure as of December 31, 2011 consisted of 1.20% short term debt; 49.00% long-term debt; 0.20% preferred equity and 49.60% common equity. The capital structure proposed in the original filing was based on a long term debt issuance of $150 million and excluded goodwill and other comprehensive income. RBH-8, p. 1.

[3] Typical residential customer is based on monthly consumption of 500 kWh. At the time of the initial filing, the typical residential gas customer was based on an annual consumption of 922 therms. In the Amended Settlement, average annual gas consumption is based on 846 therms.

National Grid, the Division and the U.S. Navy.[4] On November 14, 2012, the Company filed an Amended Settlement Agreement ("Settlement Agreement" or "Settlement") primarily to address storm costs incurred by the Company after Hurricane Sandy which surfaced in Rhode Island 10 days after the October 19 settlement agreement was filed. In comparison to the Company's original request filed April 27, the Settlement Agreement contained significant reductions in base rates, ROE, revenue requirements, revenue deficiencies and bill impacts. The Parties agreed to an electric distribution revenue requirement of $260,531,133, roughly $9.9 million lower than the Company's originally requested revenue requirement of $270,471,182. The settled upon revenue requirements were based on the Company's actual capital structure as of June 30, 2012 and authorized a base distribution rate increase of approximately $21.5 million for the Company's electric operations.[5] The bill impact associated with the electric distribution rate increase authorized in the Settlement Agreement was $2.56 per month. The reduced revenue requirement and revenue deficiency are due in part to the agreed upon lower return on equity of 9.5% and other concessions which reduced the Company's rate year cost of service for both electric and gas. For the electric revenue requirement, the Parties agreed to a lower uncollectible expense due to a lower write-off rate (1.25% versus 1.35%); lower weighted average cost of capital (7.28% versus 7.85%); and modifications to storm cost recovery and other cost recovery mechanisms discussed below.

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[4] The Wiley Center intervened in the matter on June 22, 2012; however, it did not file testimony. The Wiley Center had notice and an opportunity to contest the Settlement Agreement but did not do so. Commission Rules prohibit a settlement agreement from being defeated based on the absence of one party's signature. Rule 1.24(b)(3). RIPUC Rules of Practice and Procedure. The absence of Wiley Center's signature is non-dispositive to the decision in this matter.

[5] The Company's capital structure as of June 30, 2012, excluding goodwill and accumulated other comprehensive income, consisted of 0.76% short-term debt; 49.95% long-term debt; 0.15% preferred equity and 49.14% common equity. This capital structure reflects the anticipated $200 million long-term debt issuance approved by the Division on October 31, 2012 in Division Dkt. No. D-12-12 (4.88% interest rate and .75% debt expense). The debt issuance is to occur before May 31, 2013. If the impact of actual debt rates and issuance costs on cost of service exceeds $100,000 (electric) or $50,000 (gas), the Company will make a filing to adjust base rates within 60 days of the debt issuance. Settlement, pgs. 7-8, 16; MDL-3-ELEC-S, p. 61; Letter of Tom Teehan, p.2 (11/14/12); Division Order No. 20853 (Dkt. D-12-12).

For the Company's gas operations, the Parties agreed to a distribution revenue requirement of $167,159,844 which is a $5.9 million reduction from the $173,128,689 revenue requirement requested by the Company in its original filing. This resulted in a base distribution rate increase of approximately $11.3 million for the Company's gas operations.[6] The agreed upon gas distribution revenue requirement and revenue deficiency are based on a 9.5% ROE, as opposed to the 10.75% ROE originally requested by the Company. Additional modifications to the original proposal also contributed to the reduction in the Company's rate year revenue requirements. The bill impact associated with the gas increase was approximately $55.00 per year for an average gas residential heating customer.[7] The bill impacts for both the electric and gas distribution increases authorized in the Settlement Agreement were considerably lower than the bill impacts originally proposed by the Company ($3.97/mo. (electric) and $98.00/yr. (gas)).

The Commission approved the Amended Settlement Agreement, filed November 14, 2012, at an open meeting held on December 20, 2012.[8] Following is a summary of the pleadings and travel of this case, including the testimony that was filed prior to the settlement, the Amended Settlement Agreement, the hearing and decision.[9]

II. National Grid's Application for Approval of Change in Electric and Gas Base Distribution Rates

A. Direct Testimony of Timothy F. Horan

[6] MDL-3-GAS-S, pgs.1-2; Letter of Tom Teehan, p.2 (11/14/12).
[7] Based on average annual consumption of 846 therms. Settlement, Teehan Letter, p.2; PMN-8-5, p.1.
[8] For simplicity, the term "Parties" shall refer to the parties who signed the Amended Settlement Agreement, or National Grid, the Division and the Navy.
[9] For purposes of efficiency, this Order will not summarize the discovery filed in this docket. Throughout the period of suspension and prior to the filing of the Amended Settlement Agreement on November 14, 2012, approximately 500 data requests were issued by/between the parties.

Timothy F. Horan is President of National Grid's Rhode Island and New Hampshire jurisdictions.[10] He has held this position since 2011. Mr. Horan's testimony on behalf of National Grid consisted of a general overview of the Company's proposals and a summary of the organizational changes which have occurred within the Company since the last gas and electric rate cases were filed. Mr. Horan explained that the Company is seeking an increase of approximately $31M to the revenue requirement associated with the Company's electric operations and an increase of approximately $20M to the gas revenue requirement.[11] The revenue requirements are based on the test year ending December 31, 2011 and are supported by a lead lag study, allocated cost of service study and sales forecasts.[12] Mr. Horan cited the Company's need to recover annual operating costs as the principal basis for the Company's rate filing.[13] Mr. Horan emphasized the Company's obligation to provide safe and reliable service and the importance of that obligation in the current economic climate.[14] While customers may be particularly leery of a rate increase at this particular point in time, Mr. Horan explained that the Company's obligation to provide safe and reliable service is no less pronounced. In fact, Mr. Horan argued that the struggling economy only emphasized the Company's obligation to provide safe and reliable electric and gas service. He described this service as the backbone of the Rhode Island economy, citing tropical storm Irene as an example of the public's dependence on gas and electric service.[15] He said that the sheer volume of customers served by the Company

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[10] Mr. Horan is a retired U.S. Army Reserves Colonel and holds a B.S. Degree in Management Engineering from Worcester Polytechnic Institute and a MBA from Regis University. National Grid 1, Testimony of Timothy F. Horan, pgs. 2-4.
[11] National Grid 1, Timothy F. Horan Direct, p. 25.
[12] Id., pgs. 24-25.
[13] Id., p.4, 6.
[14] Id., p.
[15] Id., p.6.

(approximately 476,000 electric customers and 250,000 gas customers) demonstrates the crucial role of the Company in the local economy.[16]

As of January 31, 2011, National Grid reorganized its U.S. operations to consist of local state jurisdictions led by regional presidents. This structure was designed to foster efficiency in the Company's operations and improve customer responsiveness and interaction.[17] To that end, as regional President, Mr. Horan's primary responsibilities are to ensure the Company's provision of safe and reliable service in the most cost-effective manner; improve communication with local stakeholders; and build effective relationships with local government.[18] To assist Mr. Horan in achieving these objectives are four program managers serving the different geographical sections of the state.[19] Mr. Horan claimed that the new organizational structure of the Company would allow it to be more actively engaged in the local community.[20] In support of this claim, he pointed out that he has considerable management authority over the ISR programs implemented in 2011. He argued this is proof that the jurisdictional organization provides a beneficial framework for the development of the annual ISR plans because it enables the Company and the Division to collaborate in the development of the plans.[21] He also attributed the Company's response to Tropical Storm Irene to the jurisdictional model. Although he did not directly characterize the Company's restoration efforts following Irene as commendable, he suggested they were commendable, or at least positive. He referred to the Company's "steady progress in addressing the severe damage and restoring customers' power during the course of the week that followed, with 70 percent of customers restored by Tuesday, August 30, and 90

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[16] Id., pgs. 14-15.
[17] Id., pgs. 9.
[18] Id., p. 11.
[19] Id., p.15.
[20] Id.
[21] Id., p. 19.

percent of customers restored by Thursday, September 1."[22] He also referred to the lack of serious injury to either Company employees or the public during the Irene restoration efforts.[23] According to Mr. Horan, the advantage gained from the jurisdictional organization of the Company in the wake of Storm Irene was that the Company was able, with local officials, to "quickly launch a meaningful and robust review" of the Company's storm response efforts.[24] As another example of how the Company's jurisdictional model has improved the efficiency of the Company's operation, Mr. Horan cited the Company's participation in the Renewable Energy Siting Partnership ("RESP"). Mr. Horan described RESP as a project initiated by U.R.I., funded by the OER, to disseminate information on the Company's interconnection process, net metering and system reliability plan.[25] According to Mr. Horan, the efforts of the RESP have been facilitated by the jurisdictional management model in Rhode Island.[26] Finally, Mr. Horan cited the Company's participation in various community organizations, including the United Way of R.I., the Good Neighbor Energy Fund, as an example of how the jurisdictional model has "provided a platform for [Mr. Horan's] participation on behalf of the Company…" ultimately promoting "learning and understanding between the Company and its local constituencies."[27] Mr. Horan concluded his comments regarding the jurisdiction model by saying, "[W]e see the Rhode Island jurisdictional organization as being the key ingredient in aligning shareholder and customer interests to the benefit of each, and our commitment to the model reflects this perspective."[28]

Mr. Horan cited the Company's new billing system as an example of the Company's

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[22] Id., p. 20.
[23] Id.
[24] Id.
[25] Id., p. 21.
[26] Id., p. 21.
[27] Id., p. 22.
[28] Id., pgs. 23-24.

excellent service to customers. He explained that on January 23, 2012, the Company converted an outdated billing system used for its gas customers to the newer Customer Service System which is the billing system that the Company uses for its electric customers.[29] The Company now has the same billing system for both gas and electric customers. Mr. Horan said that the new system would work better and have fewer technical problems, thereby reducing the Company's on-going technical support costs.

B. Direct Testimony of Robert B. Hevert- ROE and Capital Structure

1. ROE

National Grid retained expert witness, Robert B. Hevert, to file testimony in support of an appropriate return on equity ("ROE") and capital structure for ratemaking purposes.[30] The ROE must be established in rate base proceedings in order to determine the overall rate of return a utility is allowed to earn. The rate of return is based on a utility's weighted average cost of capital, one component of which is the cost of equity. Unlike the other components of a utility's capital structure which are readily discernible (i.e., cost of debt and preferred stock), the cost of equity must be estimated based on market analysis.[31] Mr. Hevert testified that a 10.75% ROE would be necessary in order for the Company to provide an appropriate return to its equity investors.[32]

Mr. Hevert arrived at the 10.75% ROE by applying multiple analytical models to three carefully selected proxy groups of comparable utilities and taking into consideration the Company's business risk profile. Mr. Hevert applied two forms of the Discounted Cash Flow

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[29] Id., pgs. 22-23.
[30] Mr. Hevert holds a Bachelor's Degree in Business and Economics from the University of Delaware and an MBA with a concentration in Finance from the University of Massachusetts. Mr. Hevert is Managing Partner for Sussex Economic Advisors, LLC. and Executive Advisor to Concentric Energy Advisors, Inc. National Grid 1, Testimony of Robert B. Hevert, p. 1.
[31] National Grid 1, Testimony of Robert B. Hevert, p. 28, lines 12-16.
[32] National Grid 1, Executive Summary of Robert B. Hevert, p. i, 75.

("DCF") Model, two forms of the Capital Asset Pricing Model ("CAPM"), as well as the Bond Yield Plus Risk Premium approach to the proxy group companies. He also considered the following factors impacting the risk profile of the Company: the existing regulatory environment, the small size of the Company relative to the proxy groups, the Company's capital expenditure plans and overall prevailing economic conditions. Mr. Hevert's analysis also included consideration of legal precedent including the Hope and Bluefield decisions and the R.I. Decoupling Statute.[33]

Mr. Hevert first selected two proxy groups, one comprised of electric utilities and another comprised of gas utilities. The companies were selected according to Value Line's respective classifications of "Electric Utilities" and "Gas Distribution."[34] From those two lists of Value Line utilities, Mr. Hevert eliminated companies based on self-developed screening criteria intended to narrow the lists to only those utilities that are most similar to the Company. Mr. Hevert then selected a combination proxy group which consisted of companies having a combination of electric and gas operations similar to that of the Company. The Company's total regulated operations, according to Mr. Hevert, consist of 73% electric operations and 27% natural gas operations.[35] In estimating an appropriate ROE for the Company, Mr. Hevert applied the previously mentioned analytical models (DCF, CAPM and Bond Yield Plus Risk Premium) to all three proxy groups. To ensure the reasonableness of his results, and consistent with prevailing practice in ratemaking proceedings, Mr. Hevert applied multiple forms of these models to the proxy groups. He also applied weightings to those results consistent with the

[33] Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944); Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia, 262 U.S. 679 (1923); R.I.G.L. §39-1-27.7.1.
[34] National Grid 1, Testimony of Robert B. Hevert, p. 21, line 9 and p. 23, line 3.
[35] National Grid 1, Testimony of Robert B. Hevert, p. 20, lines 6-9. Mr. Hevert derived this ratio based on 3-year historical levels of the Company's operating income and plant in service. Id.

Company's combination of gas and electric operations (73% electric/27% gas) to further ensure the reasonableness of his analyses.

1. <u>Discounted Cash Flow ("DCF") Analyses</u>

As previously noted, in keeping with industry standards, Mr. Hevert applied multiple approaches of the DCF Model to three proxy groups to arrive at the recommended 10.75% ROE. Specifically, Mr. Hevert applied the Constant Growth DCF Model and the Multi-Stage DCF Model to the proxy groups. The Constant Growth DCF Model expresses the cost of equity as the sum of the expected dividend yield and long-term growth rate.[36] It is based on the theory that a stock's current price represents the present value of all expected future cash flows.[37] The Constant Growth DCF Model is defined mathematically as follows:

$$k = \frac{D(1+g)}{P_o} + g$$

where:

k = the discount rate or required ROE

P_o = the current stock price;

D = the expected dividend yield; and,

g = the expected long-term growth rate.[38]

Mr. Hevert calculated the ROE using the above formula and inserting the following inputs for price and dividend terms. For the current stock price (P_o), Mr. Hevert used the average daily closing prices for the 30, 90 and 180 trading days ended March 16, 2012.[39] For the expected dividend yield (D_o), he used the annualized dividend per share as of March 16, 2012.[40]

[36] Id., p. 31.
[37] Id., p.31.
[38] Id., pgs.31-32.
[39] Id., p. 35.
[40] Id., p.35.

For expected long-term growth rates, Mr. Hevert used Zacks, First Call and Value Line consensus growth estimates.[41]

Mr. Hevert described the Multi-Stage DCF Model as an extension of the Constant Growth DCF Model.[42] Like the Constant Growth DCF Model, the Multi-Stage DCF Model defines the cost of equity as the discount rate that sets the current stock price equal to the discounted value of future cash flows.[43] In the Multi-Stage DCF Model, however, applicable growth rates are considered over three distinct stages and in each stage. In the first two stages, cash flows are defined as projected dividends, and in the final stage, cash flows are defined as both dividends and the expected terminal stock price.[44] The dividend is the product of the projected earnings per share and the expected dividend payout ratio.[45] The terminal stock price is the present value of the remaining cash flows in perpetuity.[46] Mr. Hevert cited several benefits of the Multi-Stage DCF Model, including the fact that it acknowledges the possibility of lower payout ratios during periods of high capital expenditures.[47] The fact that the Multi-Stage DCF Model does not rely solely on Value Line for dividend growth rate projections but on consensus earnings forecasts was also cited as a benefit.[48] Finally, Mr. Hevert claimed that the multistage model assumptions could be compared to market based metrics to ensure reasonableness.[49]

Mr. Hevert used the following inputs in his Multi-Stage DCF analysis. In stage one, he used Value Line's payout ratios and took the average of the projected growth rates of Value Line,

[41] Id., p. 35.
[42] Id., p. 35.
[43] Id., p.35.
[44] Id., p.36.
[45] Id.
[46] Id.
[47] Id., p.37.
[48] Id.
[49] Id.

Zacks and First Call and used this average as the earnings per share growth.[50] In stage two, for the long-term GDP growth, Mr. Hevert used the compound growth rate in the real GDP for the period from 1929 through 2011.[51] Mr. Hevert ran the model using three separate inflation rates. He used an inflation rate of 2.45% based on spread yields between long-term nominal Treasury Securities and long-term Treasury Inflation-Protected Securities. He used an embedded inflation rate of 2.82% based on the embedded inflation in Zero-Coupon Inflation Index Swaps, and he used the average of the compound annual CPI growth rate and the annual GDP Index growth rate of 2.20% and the annual Gross Domestic Product Price Index growth rate of 1.94% projected by the Energy Information Administration.[52] The results of Mr. Hevert's DCF analyses are presented in Paragraph 4 below, along with his other model results.

2. <u>Capital Asset Pricing Model ("CAPM") Analysis</u>

Mr. Hevert also estimated the ROE by applying the Capital Asset Pricing Model to the proxy group companies. Using this model, Mr. Hevert estimated the ROE by determining the return an investor would derive from a risk-free asset, i.e. U.S. Treasuries, plus a risk premium.[53] The risk premium is the amount an investor expects to be compensated for taking on non-diversifiable risk.[54] CAPM is based on the theory that investors should only be concerned with non-diversifiable risk. Mr. Hevert calculated the ROE of the proxy companies using the following CAPM formula:

$$K_e = rf + \beta(r_m - rf)$$

where:

K_e = the required market ROE;

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[50] Id., p.38.
[51] Id., p. 38, Table 9 and p.39, lines 1-2.
[52] Id., p.39.
[53] Id., p.42.
[54] Id., p.42.

β = the Beta of a security;

r_f = the risk-free rate of return;

r_m = the required return on the market as whole; and,

The term $(r_m - r_f)$ represents the market risk premium.[55]

The Beta represents the risk of a security relative to the market as a whole and was calculated as follows.

$$B = \frac{Covariance\ (r_e, r_m)}{Variance\ (r_m)}$$

Mr. Hevert used the Beta coefficients reported by Bloomberg and Value Line which reflect 24 months and 60 months of data, respectively; however, he placed greater weight on the Bloomberg data because it did not include data from the financial market dislocation period (2008-2009).[56] For the Risk-Free Rate, Mr. Hevert used both the current 30-day average yield on 30-year Treasury bonds (3.16%) and the near-term projected 30-year Treasury yield (3.42%).[57] Mr. Hevert testified that it would not have been appropriate to use the current yield on Treasury bonds as the Risk-Free Rate with a historical market risk premium, because the current Treasury yield is affected by increased risk aversion and volatility, stemming from the financial market dislocation in 2008, that is not reflected in the historical market risk premium.[58] He claimed that use of the current Treasury yield would have understated the ROE.[59]

Mr. Hevert ran the CAPM model using two separate market risk premiums. He ran the model using a risk premium equal to the expected return on the S&P 500 index minus the current

[55] Id., pgs.42, line 17 through p.43, line 4.
[56] Id., p.44, 47.
[57] Id., p.45.
[58] Id., p.44, line 19 through p. 45, line 1.
[59] Id., p.45.

30-year Treasury Bond Yield.[60] He also ran the model using a risk premium that was calculated based on a constant Sharpe Ratio. The constant Sharpe Ratio measures the standard deviation of a security or the ratio of the risk premium relative to the risk. This ratio informs investors how much additional return he or she receives for holding a risky asset as opposed to a risk-free asset.[61] Mr. Hevert calculated the Sharpe Ratio using the following formula:

$$S(X) = \frac{(R_\chi - R_f)}{Std\ Dev\ (X)}$$

where: X = the investment;

R_χ = the average return of X;

R_f = the best available rate of return of a risk free security; and

$Std\ Dev$ = the standard deviation of r_χ

After determining the Sharpe Ratio, Mr. Hevert multiplied the Sharpe Ratio by the expected market volatility. For this calculation, he used two separate indexes—the Chicago Board Options Exhange's (CBOE's) three-month volatility index and the same thirty-day average of settlement prices of futures on the CBOE's one-month volatility index ("VIX") for July 2012 through September 2012.[62] Mr. Hevert's CAPM model results are presented in Paragraph 4 below.

3. **Bond Yield Plus Premium Analysis**

In addition to the DCF Model and CAPM, Mr. Hevert used the Bond Yield Plus Risk Premium Model to calculate a required ROE in this docket. Mr. Hevert described the Bond Yield Plus Risk Premium Model as a risk premium approach to estimating the cost of equity. Specifically, he testified that this model is based on the previously discussed notion that equity

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[60] Id., p.45. Mr. Hevert calculated the expected return on the S&P 500 using the Constant Growth DCF model.
[61] Id., p.46.
[62] Id., p.46, line 14 through p.46, line 2.

holders expect to be compensated for taking on the added risk associated with their investments.[63] In short, investors demand a risk premium for taking on added risk. Risk premium approaches estimate the cost of equity by adding the risk premium to the yield on a particular class of bonds.[64] This model, however, unlike CAPM which determines risk premium relative to the market as a whole, attempts to determine the equity risk premium based on actual authorized returns for electric and gas utilities.[65]

Mr. Hevert measured the risk premiums for 528 electric and 432 gas utilities for the period 1992 through March 16, 2012. He found that the average risk premium for electric utilities during this time period was 5.53% for electric and 5.41% for gas utilities.[66] He also found that an inverse relationship existed between interest rates and risk premiums, such that when interest rates rose during this period, risk premiums decreased.[67] He then applied the current 30-day average, as well as the near and long-term projections of the 30-year Treasury Bond Yield and found that risk premiums increased considerably resulting in ROEs ranging from 10.21% and 10.94% for electric utilities and between 9.92% and 10.80% for gas utilities.[68] Mr. Hevert then combined the bond yield plus risk premium results according to the Company's ratio of electric and gas operations (73% electric, 27% gas) and arrived at a range of ROEs between 10.06% and 10.90%.[69]

4. Model Results

Applying the aforementioned models to the three proxy group companies produced a number of mean ROE results. The Constant Growth DCF Model produced mean ROEs ranging

[63] Id., p.49.
[64] Id., p.49.
[65] Id., p.49.
[66] Id., RBH-4.
[67] Id., p.50, lines 2-3.
[68] Id., p.51, line 7 through p.52 line 7.
[69] Id., P.52.

from 9.50% to 9.80%.[70] The Multi-Stage DCF Model produced mean ROE s ranging from 10.32% and 10.49%.[71] The CAPM results using Bloomberg Beta estimates produced a range of ROEs from 9.40% to 11.03% and using Value Line Beta estimates, the range of ROEs was between 9.32% and 10.78%.[72] The Bond Yield Plus Risk Premium Analysis produced a range of weighted average ROEs (based on the Company's ratio of electric and gas operations of 73% - 27%) between 10.06% and 10.90%.[73] As previously discussed, Mr. Hevert considered these analytical results in the context of several factors which led him to ultimately recommend a 10.75% ROE. These factors are discussed below.

5. Other Factors Supporting Mr. Hevert's 10.75% ROE

a. Regulatory Environment

In addition to analyzing the results of his analytical models, Mr. Hevert took into consideration many factors affecting the risk profile of the Company. One of those factors was the regulatory environment in which the Company operates. Mr. Hevert reviewed the results of two surveys which ranked regulatory jurisdictions in terms of their credit supportiveness. The surveys were conducted respectively by Standard and Poor's ("S&P") in 2010 and Regulatory Research Associates ("RRA") in 2011. In the S&P survey that Mr. Hevert reviewed, jurisdictions were ranked on a scale of 1 through 5 with 1 equating to "least credit supportive" and 5 equating to "most credit supportive." The RRA survey awarded a ranking that consisted of either below average, average or above average, in addition to a numerical score ranging from 1 to 3, 1 being the highest. Mr. Hevert noted that Rhode Island's S&P and RRA regulatory scores

[70] Id., p.41.
[71] Id.
[72] Id., p. 48, Table 11 (Combination Proxy Group).
[73] Id., p.52.

were 2.00 and Average/3 (4), respectively.[74] He then calculated the average S&P and RRA ratings for the proxy group companies and compared them with Rhode Island's regulatory scores. The average S&P rating was for the proxy group companies was 2.82.[75] The average RRA rating for the proxy group companies was between Average/1 and Average/2 or 5.31.[76] The fact that Rhode Island ranked lower than the average regulatory rankings of the proxy group indicated to Mr. Hevert that the financial community attributed a higher regulatory risk to the Company than to the proxy group.[77] Mr. Hevert reasoned that this perception on the part of investors of a higher regulatory risk associated with the Company would support a higher ROE within the range of results produced by his analyses.[78]

b. Size Effect

Mr. Hevert cited the "long accepted" theory known as the size effect which states that small firms require a higher return on equity because of inherent characteristics which make them riskier to investors.[79] Some of these inherent characteristics are a small firm's ability relative to larger firms to endure revenue impacts resulting from weather, migration, economic downturns or other adverse events.[80] The argument is that smaller firms have a lesser ability to withstand these adverse events. Mr. Hevert cited a 2002 article from the Journal of Asset Management and a 1995 Public Utilities Fortnightly in support of the size effect argument. Using size premiums developed by Morningstar, Inc., Mr. Hevert then compared the size premium associated with the median market capitalization of the combination proxy group which was .94% to the size

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[74] Id., p.55, line 19 and p.57, lines 3-5.
[75] Id., p.55.
[76] Id., p.57.
[77] Id., p.57.
[78] Id., p.57.
[79] Id., p.58.
[80] Id., p.60.

premium for the implied market capitalization of the Company which was 1.74%.[81] Mr. Hevert claimed that the difference between these two premiums, 80 basis points, further supports a return on equity for the Company which is higher than the proxy group mean.[82] In urging the Commission to consider the size effect premium in its determination of an appropriate ROE, Mr. Hevert referred to this legislative proscription contained in the 2010 Decoupling Act:

> Actions taken by the commission in the exercise of its ratemaking authority for electric and gas rate cases shall be within the norm of industry standards and recognize the need to maintain the financial health of the distribution Company as a stand-alone entity in Rhode Island.[83]

Mr. Hevert said that in light of this legislative mandate, it was important for the Commission to consider the size effect premium in its determination of an appropriate ROE. [84]

c. Capital Expenditures

Another risk factor that Mr. Hevert included in his ROE determination arises out of the Company's capital expenditures planned in the next several years which he described as "significant."[85] Mr. Hevert did not specifically identify the capital expenditure plans or refer to a projected budget for these plans, although this was addressed in the testimony of Michael Laflamme.[86] He testified, however, that the Company's level of capital expenditures planned for years 2013 and 2014 would outpace depreciation levels by approximately 3.08 times.[87] No figures were offered in support of this comparison, but Mr. Hevert added that the level at which the Company's capital expenditures surpassed depreciation (3.08 times over 2013 and 2014) was higher than that of utilities in general. Citing a 2011 article from Barclays Capital, Mr. Hevert

[81] Id., p.60, line 20 through p.61, line 11.
[82] Id., p.60, lines 16-17.
[83] R.I.G.L. §39-1-27.7.1(b).
[84] Id., p.59, lines 8-19.
[85] Id., p.61, line 22 through p.62, line 1.
[86] Michael Laflamme's testimony is summarized on pages 47-57 of this Order.
[87] Id., p.63, lines 15-17.

said that in the utility industry as a whole, capital expenditures are typically only 2.00 times depreciation expense.[88] This significant discrepancy would suggest to investors that the Company is subject to an increased risk of depleted future cash flows, a fact which Mr. Hevert argued further supports a ROE on the higher end of the proxy group mean.[89]

d. <u>Economic Considerations</u>

Mr. Hevert emphasized the importance of considering current economic conditions in his ROE analysis. The ROE determination must consider the current state of the economy not only to ensure the reasonableness of the financial model results but to ensure the Company's continued ability to attract capital.[90] Mr. Hevert compared current and historical yield spreads and discussed the ramifications of the current widening trend in spreads. He testified that the 90-day moving average spread as of March 16, 2012 between Moody's Baa-rated utility bond index and Moody's A-rated utility bond index is 45 basis points higher than the comparable average credits spread during the pre-recession period between January of 2006 through November 2007.[91] The wide yield spread is primarily the result of lower Treasury yields caused by increased investments in government issued bonds due to market instability. Mr. Hevert testified that these wide yield spreads were indicative of a heightened sense of risk aversion on the part of investors which should equate to a higher ROE within the range of mean results produced by the financial models.[92] In short, he argued that investors typically demand increased returns in exchange for taking on risk, especially in unstable markets.[93]

<u>e. Legal Considerations</u>

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[88] Id., p.63.
[89] Id., p.64.
[90] Id., p.17.
[91] Id.
[92] Id., p.16.
[93] Id., p.15, lines 4-5 and p.16, lines 11-12.

Mr. Hevert cited the standards established in Hope and Bluefield. Hope and Bluefield refer to two U.S. Supreme Court decisions which have collectively become a benchmark in regulatory proceedings for determining the fairness or reasonableness of a return on equity.[94] As noted by Mr. Hevert, the Hope and Bluefield decisions define the fairness of a return on equity in terms of 3 separate standards. First, the ROE must be consistent with returns on equity in other businesses of similar risk. Second, an allowed ROE must be sufficient to support the utility's credit quality and access to capital. Finally, in evaluating the fairness of an allowed return on equity, the regulatory body should be concerned with the end result as opposed to the means of arriving at the return.[95] Urging the Commission to base its ROE determination on the Hope and Bluefield standards, Mr. Hevert maintained that the ROE established in this docket should achieve the following goals:

1) It should be sufficient to attract capital at reasonable terms, thereby enabling it to continue providing safe and reliable service;

2) It should be sufficient to support the financial soundness of the Company's operations; and,

3) It should be commensurate with the returns on equity in enterprises of comparable risks.[96]

In summary, the ROE established in this docket should enable the Company to finance capital expenditures at reasonable rates and maintain its financial flexibility over the period during which rates will remain in effect.[97] Mr. Hevert underscored the importance of the Company's need to attract capital and maintain financial integrity in light of the current economic conditions discussed above.

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[94] Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944); Bluefield Waterworks & Improvement Co., v. Public Service Commission of West Virginia, 262 U.S. 679 (1923).
[95] National Grid 1, Testimony of Robert Hevert, p.8, lines 4-10.
[96] Id., p.8, lines 12-
[97] Id., lines 17-19.

Mr. Hevert also cited the Decoupling Act in support of his ROE analysis. Citing the following statutory language from the statute, Mr. Hevert testified that he made no adjustments to his ROE estimate based on the rate mechanisms proposed by the Company in this proceeding:[98]

> The existence of any of the ratemaking mechanisms set forth in this section shall not be relied upon or cited for the purpose of making any adjustments in the determination of the distribution company's cost of capital.[99]

2. Capital Structure

Mr. Hevert argued in support of a proposed capital structure for ratemaking purposes that reflects the Company's actual capital structure as of December 31, 2011. The Company's actual capital structure as of December 31, 2011 was 49.60% common equity; 49.00% long-term debt, 1.20% short-term debt and 0.20% preferred equity.[100] Based on this capital structure, Mr. Hevert calculated the overall weighted average cost of capital of the Company to be 7.85% for the Company's electric distribution operations and 8.24% for gas distribution operation.[101] Citing the Decoupling Act once again, Mr. Hevert argued that the statutory mandate requiring the Commission to recognize the financial health of the Company as a "stand-alone entity" is consistent with the Company's proposed capital structure since the Company finances its rate base on a stand-alone basis and is a separately rated company carrying credit ratings from both S&P and Moody's.[102] In addition, Mr. Hevert argued that the Commission's use of the Company's actual capital structure for ratemaking purposes would not only be consistent with Rhode Island law but would ensure that costs borne by ratepayers are directly tied to capital

[98] Id., p.10.
[99] Id., p.9.
[100] Id., p.64.
[101] Id., p.68; RBH-10.
[102] Id., p.68, line 13 through p.69, line 13. R.I.G.L. §39-1-27.7.2.

dedicated to regulated utility operations.[103] Mr. Hevert advanced two other arguments in support of using the Company's actual capital structure for ratemaking purposes.

Mr. Hevert argued that use of the actual capital structure was necessary to preserve the Company's A- corporate credit rating.[104] According to S&P, companies maintaining an A- credit rating should have a total debt to capital ratio of 45% to 50%.[105] Furthermore, S&P recommends that the equity ratios of companies with A- credit ratings should be between 50% to 55%.[106] Mr. Hevert argued that setting the Company's equity ratio lower than the actual 49.60% would jeopardize the Company's A- credit rating. He added that a lower credit rating would result in higher borrowing costs which would ultimately be borne by the ratepayer.[107]

Additionally, Mr. Hevert compared the Company's proposed capital structure to the mean capital structure components of the proxy group and concluded that the proposed capital structure was reasonable. Below is an illustration of Mr. Hevert's capital structure comparison:

	The Company's Capital Structure	Proxy Group Capital Structure
Equity ratio:	49.60%	50.60%
Long-term debt ratio:	49.00%	46.15%
Short-term debt ratio:	1.20%	2.92%
Preferred Equity ratio:	0.20%	0.34%[108]

Finally, Mr. Hevert emphasized the significant impact of the ROE and capital structure established in this docket on the Company's ability to access capital and fund operations with internal cash flows. He said that sufficient cash flows will be necessary to meet investor

[103] Id., p.68.
[104] Id., p.70.
[105] Id., p.71.
[106] Id., p.72.
[107] Id.,p.73.
[108] Id, p.74; RBH-7.

expectations and sustain the Company's credit ratings, especially in the present state of the economy.[109]

C. **<u>Direct Testimony of Maureen P. Heaphy- Employee Compensation, Benefits, Pension, Other Post-Employment Benefits ("OPEB")</u>**

Maureen P. Heaphy, Vice President of U.S. Compensation, Benefits and Pensions for National Grid Corporate Services LLC, presented testimony on behalf of National Grid regarding employee and pension costs.[110] Ms. Heaphy's testimony was related to both the electric and gas operations of National Grid, and more specifically, the overall revenue requirement recommended by Michael Laflamme. Ms. Heaphy's testimony detailed the O&M expense portions of the Company's proposed revenue requirements of $270,471,182 (electric operations) and $173,128,689 (gas operations) pertaining to employee compensation, benefits and pension programs.[111] Ms. Heaphy testified that the overall employee compensation package within the Company's proposed revenue requirement is both competitive and cost-effective.[112] She explained the impact of the Company's restructuring plan on its total compensation, benefits and pension programs and testified that these expenses were reasonable and necessary for the Company to continue providing safe and reliable service to customers.[113]

Ms. Heaphy reported that as a result of the Company's 2011 restructuring plan approximately 1,400 management positions would be eliminated.[114] She also reported that prior to the Rate Year which begins on February 1, 2013 and ends on January 31, 2014, approximately 137 "non-enduring" positions would be eliminated, and the following vacancies would be filled: 118 vacancies in management; 26 incremental positions within the U.S. Foundations Program;

[109] Id., pgs.74-75.
[110] National Grid 1, Direct Testimony of Maureen P. Heaphy, p.1.
[111] National Grid 1, Direct Testimony of Michael D. Laflamme, p.22, line 13 and p.7, line 2; MDL-3-ELEC; MDL-3-GAS.
[112] Id., Testimony of Maureen P. Heaphy, p.2, lines 11-15.
[113] Id., p.3.
[114] Id., p. 5.

and 19 union positions.[115] Ms. Heaphy referred to the testimony of Michael Laflamme for further details concerning these vacancies.[116]

1. Wages and Benefits

In addition to earning a fixed and variable pay, National Grid employees receive medical, dental insurance, life insurance, a 401k plan, pensions, OPEBS, vacations and holiday.[117] Maureen Heaphy explained that but for a few exceptions, these wages and benefits are the same for all employees of National Grid's U.S. operations.[118] In order to ensure the competiveness of its employee compensation and benefits package, the Company closely monitors the existence of other employee compensation/benefit packages offered in the market.[119] In addition, the Company retained a private consulting firm, Towers Watson, to study the competitiveness of the wages and benefits offered to National Grid's management employees.[120] Towers Watson compared National Grid's employment package (management wages and benefits) to a peer group of 38 other companies and concluded that National Grid's employment package was below the median value of the peer group's employment package but within the zone of reasonableness.[121] Specifically, the study revealed that National Grid's total compensation package was between 90 and 110% of the peer group's median level of total compensation.[122] The salaries and benefits of 4,429 National Grid management employees (85.75% of National Grid's total management population as of October 31, 2011) were reviewed in this study.[123] The peer group consisted of utilities which conduct both electric and gas operations, non-energy

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[115] Id., p. 607.
[116] Id., p. 5, 6.
[117] Id., p.8, line 21 through p.9 line 1.
[118] Id., p.4.
[119] Id., p.9,15.
[120] Id., p. 9.
[121] Id.,p.9, line 21 through p.10, line 8.
[122] Id.; Id., p.10, lines 19-20. The term compensation package refers to compensation, benefits and pension. Id., p. 9, line 22.
[123] Id., p. 11; MPH-3.

utilities (i.e. telecommunications, water) and general businesses "with significant workforces in the United States."[124] The peer group companies are considered by National Grid to be companies that it competes with for its labor force.[125]

Ms. Heaphy described the Company's variable pay plan, referred to as the Annual Performance Plan, and explained how it was reflected in the proposed revenue requirement.[126] Ms. Heaphy described the Company's variable pay as a "pay-at-risk" plan whereby employees receive an incentive based on the attainment of certain goals designed to promote the interests of customers and regulators and achieve the highest level of individual performance.[127] The term "pay-at-risk" is intended to denote the fact that National Grid's employees earn variable pay only upon the achievement of clearly defined goals.[128] The goals vary depending on the employee but generally fall within one of six categories. In addition to financial and individual goals, employees are expected to pursue goals relating to customer responsiveness, safety and reliability, stewardship and optimization of cost of service measures.[129] Ms. Heaphy testified that the Company had modified the Annual Performance Plan so that it provided a "clearer linkage" to the customer.[130] She testified that 20% of the variable pay for Band B and C management employees is tied to safety and reliability, stewardship, customer responsiveness and cost of service optimization goals.[131] The remaining 80% of the variable pay for Band B and C employees was based on individual and financial objectives (individual goals- 40% and financial goals-40%).[132] 50% of the variable pay of Band D through F employees is devoted to

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[124] Id., p.10.
[125] Id., p.10.
[126] Id., p.17.
[127] Id., pgs. 17-21.
[128] Id., p.20.
[129] Id., p.17.
[130] Id., p.17.
[131] Id., p.18.
[132] Id., p.18.

achieving goals relating to safety and reliability, stewardship, customer responsiveness and cost of service optimization. The other 50% is based on individual goals.[133] Ms. Heaphy did not provide variable pay goals for Band A management employees. The goals associated with the variable pay for union workers is similar in terms of its focus on customer satisfaction and safety and reliability.[134] Ms. Heaphy acknowledged the Commission's ruling with regard to variable pay in Docket 4065. Specifically, in response to the Commission's prior decision to disallow 50% of the Company's variable pay, due to its nexus to financial goals, Ms. Heaphy asserted that the Company is not seeking recovery for any variable pay relating to the achievement of financial goals.[135]

Ms. Heaphy addressed wage increases for both union and non-union employees. She testified that National Grid's employees were projected to receive two wage increases prior to the end of the rate year-- a 3.37% increase on July 1, 2012 and a 3% increase on July 1, 2013.[136] Ms. Heaphy reported that the 3.0% increase was being provided to the entire workforce, and the 3.37% increase was for engineers and first line supervisors who are currently paid below market wages.[137] She reported that union workers received 2.5% wage increases in 2011 and 2012.

Ms. Heaphy testified that the Company's health and welfare program costs were reasonable and cited a number of cost-containment features of these programs. She cited the fact that the Company's health and welfare benefit plans (union and non-union) are self-insured which enables the Company to save considerably on administrative expenses.[138] The specific terms of the plans, including coverage for preventive check-ups and screenings, are furthermore

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133 Id., p.17.
134 Id., p.23, line 19 - p. 24, line 14.
135 Id., p.21.
136 Id., p.22.
137 Id., p.22.
138 Id., p.24. The Company's union health and welfare plans are also self-insured. Id., p.25, line 10.

designed to promote wellness and mitigate healthcare costs.[139] The Company also received a volume discount on prescription drug coverage by hiring CVS Caremark, the primary pharmacy benefits manager for all of National Grid's U.S. operations, to handle prescription coverage for union health and welfare plans.[140] In addition to these savings, Ms. Heaphy reported a number of changes to health coverage which the Company implemented in January of 2011 and 2012 to reduce healthcare costs.[141] Among these changes are increased co-pays for office visits and brand drugs, required union employee contributions for medical and dental plans and reduced medical opt-out credits for union employees.[142] Ms. Heaphy reported that the Test Year Expense had been adjusted to reflect projected annual increases of 9% and 7% in costs associated with medical and dental benefits respectively.[143] According to Ms. Heaphy, these projections were based on "national projections for healthcare trends and on the projections gathered by Towers Watson."[144] No further detail was provided in support of the projected healthcare cost increases.

2. Pension Adjustment Mechanism ("PAM")

Ms. Heaphy testified briefly in support of the Company's proposed pension adjustment mechanism ("PAM"). A detailed explanation of the PAM is provided in Paragraph D(4) below; however, for purposes of this section, the PAM is an adjustment mechanism that would reconcile the Company's annual pension and other post-employment retirement benefit ("OPEB") costs.[145] Ms. Heaphy claimed that the pension adjustment mechanism would ensure that customers are not

[139] Id., p. 24, line 23 - p. 25, line 4.
[140] Id., p. 25. The Company began receiving prescription drug coverage from CVS Caremark as of January 1, 2012. Id., p. 25.
[141] Id., pgs. 25 – 27.
[142] Id.
[143] Id., p. 27.
[144] Id., p. 27.
[145] National Grid's proposed PAM is reviewed in Mr. Doucette's Direct Testimony on pgs.35-38.

over-billed for these expenses which, by nature, are particularly difficult to predict because they rely heavily on forward looking estimates of future costs.[146]

3. Pension/Retirement Benefits

Ms. Heaphy testified that the Company had made concrete efforts to control pension costs since the last rate case. She stated that existing management employees would continue to participate in the cash balance pension plan; however, as of January 1, 2011, the benefits are calculated according to one formula, as opposed to the two separate formulas which were used prior to the 2011 restructuring.[147] National Grid's contribution ranges from 4% to 8% of total cash compensation but is based on the age and years of service of the employee.[148] Furthermore, as of January 1, 2011, all newly hired management employees will no longer be entitled to the traditional defined benefit pension plan. Instead, all new management employees will participate in a defined contribution plan (401k) in which the Company will contribute based on the same formula used in the cash balance pension plan.[149] Similar to the cash balance pension plans for existing management employees, the Company's contribution to the defined contribution plans of newly hired management employees will range from 4% to 8% based on the age and years of service of the employee.[150] Ms. Heaphy testified that the 401k plan would provide flexibility and portability which are attractive to the contemporary mobile workforce.[151] Finally, Ms. Heaphy testified that the Company had consolidated all of its 401k administration with Vanguard and its pension administration with Towers Watson.[152]

4. Other Post Retirement Benefits ("OPEB")

[146] Id., p. 28.
[147] Id., p. 34.
[148] Id., p. 34.
[149] Id., p. 34, line 21 through p. 35, line2.
[150] Id., p. 354.
[151] Id., p. 35.
[152] Id., p. 35.

Ms. Heaphy provided examples of how the Company had managed OPEB costs since the last rate case was filed in 2009. She reviewed the Company's OPEB benefits, including revisions to benefits, and explained how these revisions generated cost savings. Since the 2009 merger of National Grid with KeySpan, National Grid has attempted to align retirement and post-retirement benefits offered by the legacy KeySpan with National Grid's management benefit plans in a cost-effective manner without compromising the competitiveness of the plans.[153] In the process of aligning the KeySpan and National Grid OPEBs, the Company has taken several cost control measures which are summarized below.

As of July 2, 2010, the administration of all active and retiree benefit plans was consolidated with a single vendor.[154] With regard to post-retirement medical benefits, National Grid will continue to share the cost of pre- and post-65 medical coverage of employees hired before January 1, 2011, with contributions based on the number of service years at retirement.[155] Ms. Heaphy implied there may be exceptions to the Company's cost sharing of post-65 coverage but did not provide further specification of any such exceptions.[156] Employees hired after January 1, 2011 are entitled to retiree medical coverage upon attaining the age of 60 and 10 years of service. The Company pays 50% of the cost of the medical coverage for retirees up to the age of 65; however, after age 65, retirees must pay the full cost of their medical coverage.[157] This change is expected to produce cost savings over time.[158] The Company also made changes to the life insurance plan offered to retirees. As a result of the KeySpan merger, as of May 1, 2012, the retiree life insurance benefit will be $20,000 for both pre- and post-65 coverage which is less

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[153] Id., p. 29, 30.
[154] Id., p. 29.
[155] Id., p. 30.
[156] Id., p. 30, lines 6-8. "National Grid will continue to share the cost of pre-65 coverage, and *in most cases* will share in the cost of post-65 retiree coverage (emphasis added)."
[157] Id., p. 30.
[158] Id.

generous than the retiree life insurance benefit offered by KeySpan.[159] Ms. Heaphy also pointed out that union retirees would receive prescription drug coverage through CVS Caremark (similar to active union employees) allowing the Company to reduce administrative expenses through economies of scale and deeper discounts.[160]

Ms. Heaphy reviewed two revisions to the Company's post-retirement benefits precipitated by recent federal health care reforms. Beginning on January 1, 2013, National Grid will participate in an Employer Group Waiver Plan ("EGWP") and contract with a third party to administer a federally subsidized prescription drug program for retirees created by the Patient Protection and Affordable Care Act ("PPACA"). Through EGWP, National Grid will receive federal subsidies for retiree prescription drug benefits. This system will replace the current retiree drug subsidy program which is being phased out by the PPACA. According to Ms. Heaphy, the EGWP will produce savings through coordinated pharmaceutical manufacturer discounts on brand drugs under the PPACA, as well as federal catastrophic reinsurance payments.[161] Ms. Heaphy claimed the move to EGWP would result in a one-time reduction in plan obligation of approximately $375 million and ongoing annual savings of approximately $62 million.[162] Ms. Heaphy also reported savings of approximately $4.6 million already realized from the Early Retiree Reinsurance Program established pursuant to the PPACA. This program provides federal reimbursement for 80% of early retirees' (ages 55 to 64) aggregate health claims which are between $15,000 and $90,000 per plan year until the federal funds for this program are

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[159] Id. Maureen Heaphy did not identify the amount of the retiree life insurance benefit provided by KeySpan saying only that it was "more favorable."
[160] Id., p. 31.
[161] Id., p. 32
[162] Id., p. 32. Ms. Heaphy's savings estimates were not supported by any documentation.

exhausted or January 1, 2014.[163] As of March 2012, the federal government has reimbursed National Grid approximately $4.6 million pursuant to this program.[164]

D. Testimony of Stephen F. Doucette- Pension Adjustment Mechanism ("PAM")

Stephen F. Doucette is an actuary, employed by Aon Hewitt, who has been providing actuarial consulting services to National Grid since 1994.[165] On behalf of National Grid, Mr. Doucette advocated in support of implementing a pension adjustment mechanism ("PAM") in the Company's electric operations. Mr. Doucette described the retirement plans offered by National Grid in the context of prevailing trends in retirement and pension planning. He also described the PAM itself, how it would work and the reasons why it was necessary.

1. Decline of the Defined Benefit Plan

After explaining the difference between the two types of retirement plans generally offered by employers, Mr. Doucette reported that the defined benefit plan has been gradually disappearing from the workforce over the past two decades. Due to the mobility of the current workforce and economic conditions, defined benefit plans have become less popular than the portable and more flexible defined contribution and hybrid plans. The defined benefit plan guarantees a set amount upon retirement based on the retiree's age, average salary over the service term and number of service years.[166] Gains and losses in the value of the defined benefit plan are borne by the employer and must be included in the employer's annual expense accounting.[167] Some defined benefit plans require employee contributions, others do not.[168]

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[163] Id., p. 33, lines 9-14.
[164] Id., p. 33, lines 19-20.
[165] National Grid 1, Testimony of Stephen F. Doucette, p. 1, lines 16-17.
[166] Id., p. 5.
[167] Id., p. 5.
[168] Id., p. 5.

Utilities, including National Grid, generally do not require employees to contribute to defined benefit plans.[169]

Unlike a defined benefit plan, the defined contribution plan does not guarantee a set amount at retirement based on a formula. Defined contribution plans are funded by the employee and the employer, usually a percentage of salary which is matched by the employer.[170] Gains and losses associated with a defined contribution plan are not assumed by the employer. On the contrary, gains and losses of the plan, along with the contributions made over the life of the plan, ultimately determine the amount paid to the retiree.[171] To offset the risk that employees assume for the gains and losses associated with a defined contribution plan, they also enjoy discretion over the investment of the funds that comprise the plan and flexibility in the terms and conditions of withdrawing those funds.[172]

Over the past 10 years, employers have begun to offer hybrid retirement plans which resemble both defined benefit and defined contribution plans.[173] The hybrid plan is essentially a defined benefit plan in the sense that it promises a set amount at retirement, is funded by the employer, and gains and losses in the value of the plans are assumed by the employer.[174] In a hybrid plan, however, the future benefit depends on the account balance of the plan at retirement and may be received in the form of an annuity or lump sum, as determined by the retiree.[175]

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[169] Id.
[170] Id., p. 5.
[171] Id., p. 5.
[172] Id., p. 5.
[173] Id., p. 6, line 21 through p. 7, line 1.
[174] Id, p. 7.
[175] Id., p. 7.

Over the years, hybrid plans, such as the cash balance plan described above, have become more popular, and most recently, defined contribution plans have become the most common type of retirement plan offered in the market.[176]

The defined contribution plan has become popular because of its appeal to both employers and employees. Employers have limited exposure with the defined contribution plan, their only expense being that of the annual contribution made to the plan.[177] This annual expense is not impacted by market conditions, allowing the employer a level of predictability in future costs not realized with a defined benefit or hybrid plan.[178] Also, employers are not liable for investment gains and losses associated with a defined contribution plan.[179] Finally, employers are more likely to attract qualified employees with a defined contribution plan because of its portability.[180] Defined contribution plans may be transferred to a new 401k or IRA if an employee leaves his or her employment. As changes in employment are much more common today than in years past, the portability of the defined contribution plan is appealing to both employees and employers alike.[181] Finally, employees like the transparency of the defined contribution plan, their ability to control the amount of their contributions, the type of investments in their account, the ultimate growth or value of the account and how the funds in the account are withdrawn.[182]

2. National Grid's Retirement Plans

The retirement plans offered at National Grid in recent years have been consistent with the market trend, with a gradual transition from the defined benefit plan to the defined

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[176] Id., p. 7, 8, Table 1.
[177] Id., p. 9.
[178] Id., p. 9, line 20 through p. 10, line 5.
[179] Id., p. 9.
[180] Id., p. 8.
[181] Id., p. 9.
[182] Id., p. 9, 6.

contribution plan. On July 14, 2002, the Company stopped offering the defined benefit plan to all non-union employees hired after this date. Instead of the defined benefit plan, the Company began offering the cash balance pension plan (hybrid plan) to all non-union employees hired after July 14, 2002.[183] On January 1, 2011, the Company began offering the defined contribution plan to all non-union employees hired after this date.[184] Although union employees continue to receive a defined benefit plan, Mr. Doucette explained that it was in the process of transitioning future union employees to the defined contribution through collective bargaining negotiations.[185] Mr. Doucette pointed out that despite the Company's shift away from the defined benefit plan, it is nonetheless obligated to honor its commitments to retirees hired before January 1, 2011 who are still eligible to receive the retirement benefit promised pursuant to the defined benefit plan.[186] The Company, furthermore, continues to bear the costs associated with these previous commitments, the calculation of such costs being dictated by Financial Accounting Standards.[187]

3. National Grid's Other Post-Employment Benefits ("OPEB")

National Grid's post-employment retirement benefits have been scaled back over the years. Presently, the Company pays a maximum of 50% of pre-65 medical coverage and 0% of post-65 medical coverage to non-union employees hired after January 1, 2011.[188] This is a substantial change from the retiree benefits that National Grid used to offer. Prior to 1991, the Company used to pay 100% of retiree medical and life insurance costs for non-union retirees.[189] National Grid started to limit OPEB coverage after 1990 when non-union employees having less

[183] Id., p. 12.
[184] Id., p. 12.
[185] Id., p. 12.
[186] Id., p. 10.
[187] Id., p. 10. Financial Accounting Standards are discussed in Paragraph D(4) below (pgs.36-38).
[188] Id., p. 14.
[189] Id., p. 13, lines 17-18.

than 30 years of service were required to contribute toward retiree medical coverage.[190] Similarly, the Company's monthly OPEB contribution is only $4.50 per number of service years for post-65 coverage for single, union employees and $9.00 per service years for married, union employees.[191] Union retirees contribute the same amount as active union employees for pre-65 medical coverage.[192]

4. <u>National Grid's Proposed PAM</u>

Mr. Doucette explained why the Company was proposing a PAM for its electric operations. As previously noted, a PAM has already been implemented and currently exists for the Company's gas operations. According to Mr. Doucette, a PAM is necessary to annually reconcile the Company's OPEB and historical pension costs, i.e. defined benefit costs, because these costs are unknown until many years in the future and highly subject to market influences beyond the control of the Company.[193] As previously noted, although the Company has moved away from defined benefit plans, it is still obligated to fulfill its obligations under these plans which are still in effect for retirees hired before January 1, 2011. In Mr. Doucette's words, the Company's opportunity to control these costs, aside from transitioning to defined contribution plans (which the Company has already done), does not exist.[194] Similarly, the Company must fulfill all of its obligations with respect to OPEBs which include those made before and after the January 1, 2011 cost control measures.[195] Since actual pension and OPEB expenses are not known for many years, they must be projected using various assumptions that involve factors outside the control of the Company and subject to a high degree of variability.[196] Mr. Doucette

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[190] Id., p. 13, lines 18-20.
[191] Id., p. 14, lines 9-12.
[192] Id., p. 14, lines 12-13.
[193] Id., p. 11, lines 2-5; p. 27, lines 6-16; p. 28, lines 10-22.
[194] Id., p. 11, lines 14-15.
[195] Id., p. 13, lines 11-13.
[196] Id., p. 27, lines 6-14.

claimed that the past 10 years had revealed a high degree of market variability which may continue into the future.[197] The PAM would ensure that the Company recovers its pension/OPEB costs and prevent the possibility of customers paying a fixed amount in rates that may in fact be higher than the Company's actual expense in any given year.[198]

The calculation of pension and OPEB expense are governed by financial accounting standards ("FAS") 87 and 106. Both of these statements reflect the accrual method of accounting and require that expenses are earned and recorded while the employee is working. FAS 87 governs the calculation of pension costs, and FAS 106 governs the calculation of OPEBs. Mr. Doucette's testimony regarding the calculation of pension expenses was limited to FAS 87. According to FAS 87, the Company records pension expenses annually as the present value of the benefit expected to be paid to the employee during retirement.[199] The present value of this benefit, or the Net Periodic Benefit, is calculated according to the following mathematical formula:

Net Periodic Benefit = Service Cost + Interest Cost – Expected Return on Assets + Amortization of Unamortized Items (Prior Service Cost/Credit and Actuarial Gains and Losses) [200]

where:

Service Cost = the present value of additional benefits earned by employees participating in the plan during the upcoming fiscal year[201]

Interest Cost = interest on the Projected Benefit Obligation ("PBO") due to the passage of time[202]

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197 Id., p. 27, lines 20-22.
198 Id., p. 27, line 22 – p. 28, line 6.
199 Id., p. 15, line 22 – p. 16, line 3.
200 Id., p.16.
201 Id.

Expected Return on Assets = the investment return expected to be earned on assets during the fiscal year[203]

Amortization = the amortization of Prior Service Cost and Actuarial Gains and Losses[204]

(Prior Service Cost is any change in the PBO caused by changes in the structure of pension benefits.)[205]

The two components of this formula which have the most impact on the variability and magnitude of the pension expense are the actual return on assets and the discount rate assumption.[206] The actual return on pension funds depends heavily on prevailing market conditions and therefore often varies significantly from the expected return.[207] The Company has no control over fluctuations in the market which inevitably impact the value of its pension funds.[208] Furthermore, any attempt to mitigate this impact by shifting pension funds into fixed income assets would only increase future pension expenses (since the expected return on assets would be lower).[209] The discount rate assumption also affects the variability of the Company's pension expenses because of the restrictions that govern the selection of this assumption. FAS 87 requires employers to select a discount rate assumption that relies on rates of return currently available in the marketplace for high-quality fixed income investments.[210] High quality fixed income investments are defined by law as securities that receive one of the two highest ratings from a recognized credit rating agency.[211] These two restrictions significantly limit the

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202 Id., p.19.
203 Id., p.17.
204 Id., p. 15, line 20 – p. 18, line 17. The Company's pension expense also includes the amortization of a regulatory liability incurred when it was acquired by National Grid in 2000. Id, p. 18, lines 20 - p. 19, line 2.
205 Id., p.18.
206 Id., p. 19.
207 Id., p. 19, line 21 – p. 20, line 2.
208 Id., p. 20.
209 Id., p. 20.
210 Id., p. 22.
211 Id., p. 22.

Company's discretion in selecting an appropriate discount rate assumption to be used in calculating its pension expense. According to Mr. Doucette, they also cause a significant amount of variability in the pension expense since the Company has no control over corporate bond yields in the market.[212] Other factors which affect the pension expense calculation to a much lesser extent are projections of compensation increases, retirement age, withdrawal rates, mortality, medical trends, medical claim costs, participation rates and disability rates.[213]

E. <u>Direct Testimony of Evelyn M. Kaye- Uncollectible Accounts Expense</u>

Evelyn M. Kaye, Vice President of Transactions Delivery Centers for National Grid USA Service Company, presented testimony regarding the Company's recovery of commodity related uncollectible accounts expense.[214] Ms. Kaye reviewed the Company's efforts to mitigate its uncollectibles expense. She explained the Company's current collection practices and reviewed plans to revise certain practices. Currently, the Company categorizes customers into five (5) groups according to risk and designs collection practices according to the degree of risk associated with each customer.[215] The Company refers to this risk scoring system as the Portfolio Management Package or "PMP."[216] The Company also manages a "Lockbox Program" whereby customers with a history of two returned checks are coded as "cash only." The Company rejects checks received from these customers at the "lockbox" and notifies them that payment was not accepted.[217] The Lockbox Program reduces the Company's processing costs, bounced check and collection fees.[218] The Company has also increased visits to multi-family

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[212] Id., p. 22.
[213] Id., p. 23.
[214] Id, Direct Testimony of Evelyn M. Kaye, p.1.
[215] Id., pgs. 12-13.
[216] Id., p.12.
[217] Id., p.15.
[218] Id., p.16.

dwellings where meters are inaccessible for purposes of initiating terminations.[219] The Company also offers various protections to certain customers. Currently, if a customer is "seriously ill," it can prevent termination of utility services for one full year.[220] According to Ms. Kaye, the Company has recently increased termination filings in order to address increasing balances maintained by certain customers. By increasing the number of termination filings, the Company has successfully managed to avoid termination in many cases through payment plans.[221] The Company engages in a multitude of outbound calling to remind customers of late payments, defaulted payment agreements and the like.[222] Finally, the Company files liens against customers with a balance of more than $5,000.[223]

Despite the Company's efforts to mitigate its uncollectibles expense, Ms. Kaye expressed doubt over the Company's ability to hold the uncollectibles level steady in the rate year. She mentioned certain factors beyond the control of the Company that may cause an increase in the rate year uncollectibles expense. Specifically, Ms. Kaye testified that the economic recession and steady unemployment rate may counteract any positive impact that declining energy prices may have on the rate year level of uncollectibles.[224] She cited several related circumstances which could potentially drive the uncollectible level up in the rate year. She mentioned rising gasoline and health care costs, the regulatory environment and the availability of LIHEAP funds.[225] She mentioned that the Company suspended its collection activities during Tropical Storm Irene which increased accounts receivable, and she mentioned the recent extension of the

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[219] Id.
[220] Id., p.18.
[221] Id., pgs. 14-15.
[222] Id., p. 17.
[223] Id., p.12, 17.
[224] Id., p.7.
[225] Id., p.8.

winter moratorium from April 15 to May 1.[226] She reported that in the 2011-2012 LIHEAP season, Rhode Island received 25% less LIHEAP funds than it received in the previous year.[227] Ms. Kaye contended that all of these circumstances contributed to a potential rise in uncollectibles in the rate year.[228]

To ensure the Company fully recovers its commodity related uncollectible expense in the rate year, Ms. Kaye proposed the establishment of an uncollectible net write off rate of 1.35% (electric) and 3.35% (gas).[229] These rates represent the Company's three (3) year aggregate net write-off rate rates for electric and gas delivery revenues.[230] Currently the Company recovers bad debt costs based on a five year average net write off rate which in 2011 was 1.32%.[231] According to Ms. Kaye's proposal, the Company would be allowed to reconcile any differences between its actual, commodity related net write-offs and revenues derived from the proposed net write-off rates of 1.35% (electric) and 3.35% (gas).[232] Ms. Kaye testified that she proposed three (3) year aggregate net write off rates instead of the 5 year aggregate net write off rate approved in 4065 and 3943, because the three (3) year period ending in December of 2011 is coincident with Rhode Island's severe economic recession and therefore more indicative of rate year expense.[233] The three (3) year rate would also normalize impacts from weather and commodity cost fluctuations.[234] Ms. Kaye's proposed write off rates yield write off amounts of $35,018,924

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[226] Id., p.9.
[227] Id., p.10.
[228] Ms. Kaye referred to a gas marketing proposal which could also drive up the uncollectible rate; however, no further explanation was provided regarding this proposal or specifically how it would impact uncollectibles. Id., p.11.
[229] Id., pgs. 18-19.
[230] Id.
[231] EMK-1, p.1.
[232] Id., p.19.
[233] Id., p.20.
[234] Id.

(electric) and $46,579,771 (gas).[235] Ms. Kaye further testified that it was in the best interest of customers and the Company to use three (3) year averages since this year's mild winter, combined with increased write offs, would drive up the average write-off rates, and it is not known how long this trend will endure.[236] According to Ms. Kaye, using the three (3) year average write-off rates would prevent customers from paying an uncollectible accounts expense that is higher than what the Company actually incurred.[237] Conversely, limiting the Company's uncollectible accounts expense and commodity related administrative costs to the level yielded by the proposed three (3) year average net write-off rates was fair and appropriate to the Company since it does not earn a profit from the commodity portion of its services.[238]

Ms. Kaye testified that the proposed net write off rates and reconciliation mechanism would not serve as a disincentive to the Company to mitigate uncollectible accounts expense. In support of this representation, Ms. Kaye testified that one of the Company's existing collection practices, the risk scoring system or "PMP" described above, would be extended to gas customers.[239] Furthermore, this proposal would not affect the Company's exposure to delivery portion of bills. The Company would still be exposed to variability in the uncollectible accounts expense associated with the delivery portion of customers' bills.[240] Ms. Kaye stated that these factors would all serve to mitigate the Company's net write-offs, but to further mitigate write-offs, Ms. Kaye stated that the Company is planning certain modifications to its collection practices. The Company plans to develop guidelines to distinguish seriously ill customers from handicapped customers so that the protection period will be more closely aligned with the

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[235] Id.
[236] Id.
[237] Id., p.21.
[238] Id.
[239] Id., p. 22.
[240] Id.

specific need of the customer.[241] The Company also intends to require deposits for short term residential leases of less than one (1) year.[242] Finally, the Company proposed a personnel addition of two Consumer Advocates, whose primary duties would be to serve elderly, low-income, disabled and medical customers.[243] These advocates would provide information to the aforementioned customers that would assist them in paying their bills including balance billing, third party notification, large-print billing, braille billing, bill extensions, energy savings tips and low income rates.[244]

F. Direct Testimony of Michael R. Hrycin- 19 Union, Electrical Workers

The Company presented the direct testimony of Michael R. Hrycin, Director of Overhead Lines for Narragansett Electric Company.[245] Mr. Hrycin oversees maintenance and construction for all of Narragansett Electric's overhead infrastructure, including distribution and sub-transmission facilities in the state of Rhode Island.[246] Mr. Hrycin proposed an increase of $1.8 million annually to the electric revenue requirement for the purpose of funding the hiring of nineteen (19) union, electric workers.[247] Mr. Hrycin testified that the nineteen (19) electrical workers were necessary to address an aging workforce, the anticipated retirement of union employees and the resulting need for skilled workers to fill these vacancies.[248] Approximately 30% of Narragansett Electric's union workforce is eligible for retirement within the next five (5) years.[249] The aging work force is endemic to the entire utility industry with the U.S. Department

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[241] Id.
[242] Id., p.18.
[243] Id.
[244] Id., pgs. 23-25. The Company requested but was denied the two consumer advocates in the last base distribution rate case (Docket 4065).
[245] Id, Direct Testimony of Michael R. Hrycin, p. 1.
[246] Id.
[247] Id., p.5.
[248] Id., p.6.
[249] Id. This percentage is based on a retirement age of 60. If workers retire early, as much as 50% of the workforce could retire within the next five (5) years. Id.

of Labor estimating that approximately 500,000 energy industry workers will retire within the next five (5) to ten (10) years.[250] Mr. Hrycin also reported that the request to fund nineteen (19) additional workers was also necessary to fulfill staffing requirements mandated in union contracts with Local 310 BUW Council/UWUA AFL-CIO ("Local 310").[251] The Company signed a collective bargaining agreement on May 12, 2007 that required Narragansett Electric to achieve minimum staffing requirements for overhead, underground and substation crews.[252] After the Commission denied the Company's original request for nineteen (19) additional union, electrical workers in 2009 (Docket No. 4065), Narragansett Electric signed a Memorandum of Understanding with Local 310 to extend the deadline for hiring the contract's minimum staff requirement.[253] If hired, Mr. Hrycin explained that these workers would not replace outside contractors because they would be hired as trainees and would not be considered permanent employees until they have completed four (4) years of training.[254] Mr. Hrycin testified that the addition of these workers was critical to maintaining the safety and reliability of Narragansett Electric's distribution system which is comprised of approximately 5,283 miles of overhead and 1,117 miles of underground distribution and sub-transmission circuit in a network of 99 sub-transmission lines and 388 distribution feeders.[255] The electric distribution system also includes 280,740 poles, 4,812 manholes and 64,290 overhead and underground transformers.[256] These assets serve 476,000 customers in a geographical area spanning approximately 1,076 square miles and 38 cities and towns.[257] Citing the many different causes of power outages, including

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[250] Id.
[251] Id. The Company requested but was denied funding for nineteen (19) union, electrical workers in Docket 4065. Id., pgs. 3-4.
[252] Id., p.3.
[253] Id., p.4.
[254] Id., pgs.2-4, 10-11.
[255] Id., pgs.8-9.
[256] Id., p.9.
[257] Id.

deteriorated equipment and tree related incidents, Mr. Hrycin emphasized Narragansett Electric's need to maintain a highly skilled workforce to ensure the reliability of its distribution system.[258]

G. **Direct Testimony of Jeffrey P. Martin- Gas Billing Conversion and Paperless Billing Credit**

Jeffrey P. Martin is Director of Billing Operations at National Grid USA Service Company, Inc.[259] Mr. Martin testified regarding the Company's gas billing conversion and proposal for a paperless billing credit. On January 23, 2012, the Company converted its gas billing system from its two legacy systems, Advantage/Banner and Local Distribution Company Manager ("LDCM"), to a new billing system known as the Customer Service System ("CSS").[260] The two former billing systems, more than twelve years old, were left over from the prior takeover of Southern Union Company and were highly dysfunctional and inefficient.[261] The total cost of the conversion was $14.7 million which Mr. Martin testified was low relative to the benefits achieved in comparison to other options that the Company had considered.[262] The per-customer cost of the project is approximately $57 which is within the median per- customer cost for comparable billing conversions of this nature and magnitude.[263] Mr. Martin proposed amortizing the cost of the conversion ($14 million) over eight (8) years and continuing the amortization of the legacy Advantage system through August of 2017.[264] The continued amortization of the Advantage system was warranted since the old system would remain in "read

[258] Id., pgs. 9-10.
[259] National Grid USA Service Company, Inc. is a subsidiary of National Grid USA ("National Grid"). Id., Direct Testimony of Jeffrey P. Martin, p.1.
[260] Id., p.5,7.
[261] Id., p.5.
[262] Id., p.8.
[263] Id.
[264] Id., p.11.

only" mode for the duration of the amortization period in order to allow access to customer account information.[265]

Among the benefits of the new CSS billing system are quicker payment processing, electronic billing and payment for gas customers and the potential for consolidating gas and electric accounts into one bill.[266] Gas customers would have the option to select paperless billing for which they will receive a credit of $0.33 on the delivery portion of their monthly bill.[267] This credit would be offered only to customers opting for paperless billing and would have no restrictions as far as duration or commitment.[268] Customers would be allowed to opt in and out of paperless billing at any time.[269] While the Company currently offers paperless billing to both electric and gas customers, the savings associated with this option are spread among all rate classes. By offering a credit specifically to those customers who choose paperless billing, the Company hopes to provide a greater incentive for paperless billing, thus achieving economic and environmental benefits from reduced costs and reduced paper.[270] It hopes to increase the percentage of electric and gas customers with paperless billing which is currently only 12%.[271]

H. Direct Testimony of Alfred P. Morrissey- Electric Load Forecasting

On behalf of National Grid, economist, Alfred P. Morrissey, developed and presented the forecast of gigawatt-hour ("gWh") sales, customer counts and megawatt demand used to project the Company's rate year revenues, fully allocated cost of service study and rate design.[272] Mr. Morrissey's forecasts are derived from econometric models that relate sales to variables such as

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[265] Id.
[266] Id., p.10.
[267] Id., pgs.12-13.
[268] Id., pgs. 12-15.
[269] Id.
[270] Id., pgs. 13-14.
[271] Id., p.11,14.
[272] Id., Direct Testimony of Alfred P. Morrissey, p.3. Mr. Morrissey's testimony relates to the Company's electric operations.

local economic conditions, weather, the price of electricity and the number of days billed.[273] The models use Moody's economic forecast and assumes normal weather and constant electricity prices during the forecasted period.[274] The models also assume a continuation of the energy efficiency savings and trends associated with the historical period from 1990 through the end of the test year or December 31, 2011.[275] The number of days billed is take taken from the meter reading schedule.[276]

Mr. Morrissey reported that according to Moody's forecast, Rhode Island employment is expected to rebound sharply in 2013 and 2014.[277] Based on Moody's, Mr. Morrissey reported that the Rhode Island employment rate is expected to rise at an average annual rate of 0.8% between the test year (2011) and the rate year (2013).[278] Mr. Morrissey predicted growth in several other economic indicators during this same period, including real personal income, gross state product, population and number of households.[279] Mr. Morrissey forecasted an average growth in residential sales of 0.4%.[280] Mr. Morrissey attributed this modest residential sales growth, despite improved economic conditions, to the continued increase in energy efficiency programs.[281] The number of residential customers was expected to increase 0.9%.[282] He reported an anticipated increase of 2.5% in commercial gWh sales between the test year and rate year, with the number of commercial customers increasing by 1.9% per year.[283] Industrial gWh sales were forecast to decline 1.4% per year, with the number of industrial customers expected to

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[273] Id., p.5.
[274] Id., pgs. 5-6.
[275] Id., p.10; APM-6, p.1.
[276] Id., p.6. The number of days billed refers to the number of days between meter readings when customer gigawatt-hour data is collected. Id., p.9.
[277] Id., p.7.
[278] Id.
[279] Id., pgs.7-8. All forecasts in this paragraph refer to the period between the test year (2011) and rate year (2014).
[280] Id. P.14.
[281] Id.
[282] Id.
[283] Id, p.15.

increase 1.0% based on Moody's forecast of local manufacturing employment.[284] Mr. Morrissey predicted an annualized megawatt growth rate in monthly peak demand of 2.7% between the test year and rate year.[285]

I. <u>Direct Testimony of A. Leo Silvestrini- Gas Load Forecasting</u>

A.Leo Silvestrini serves as Manager of Gas Load Forecasting and Analysis for National Grid USA Service Company, Inc.[286] Mr. Silvestrini presented the Company's rate year gas sales and customer count forecasts. The Company's projected rate year gas revenues and gas rate design were based on Mr. Silvestrini's forecasts.[287] Mr. Silvestrini projected an average annual growth in the number of gas customers of 0.4%.[288] Gas deliveries, according to Mr. Silvestrini, are expected to decrease -0.9% per year, compared to a declining rate of -0.2% for the period 2005 through 2011.[289] Mr. Silvestrini's models contained assumptions based on Moody's economic forecast. He assumed, for instance, that Rhode Island's economy experienced an accelerating annual growth rate of 5.5% in 2012 and 2013, and that it would taper off to 4.5% by 2014.[290] He assumed Rhode Island employment growth rates of 2.9% in 2012, 1.9% in 2013 and 2.9% in 2014, based on Moody's forecast.[291] Mr. Silvestrini did not subtract from the models incremental savings associated with gas energy efficiency programs since future savings goals associated with these programs were not greater than historical savings.[292]

J. <u>Direct Testimony of Michael D. Laflamme</u>

[284] Id., p.16.
[285] Id., p.19; APM-7.
[286] Id., Direct Testimony of A.Leo Silvestrini, p.1.
[287] Id., p.2.
[288] Id., p.13; ALS-6. Unless otherwise specified, growth rates in this paragraph pertain to the period between the test year and rate year.
[289] Id., p.13, ALS-3, ALS-4.
[290] Id., pgs.13-14.
[291] Id., p.14.
[292] Id., p.12.

National Grid presented the direct testimony of Michael D. Laflamme, Vice President, Regulation and Pricing Officer, New England for National Grid USA Service Company, Inc.[293] Mr. Laflamme's testimony covered seven (7) topics: 1) test year service company costs; 2) the re-allocation of test year service company costs as a result of the Company's corporate restructuring; 3) rate year revenue requirements and revenue deficiencies for the Company's electric and gas distribution operations; 4) calculation of the rate base amount to be recovered in base distribution rates; 5) the amount of pension and other post-employment benefits ("OPEBS") to be included in the existing gas pension adjustment mechanism (P&PBOP Adjustment) and the proposed electric pension adjustment mechanism ("PAM"); 6) the Company's proposal to reinstate of the storm fund; and 7) the Company's proposal to implement a property tax recovery mechanism.[294] The bulk of Mr. Laflamme's testimony concerned the development and calculation of normalizing and pro forma adjustments to the Company's test year revenues.

1. Test Year Service Company Costs. Before describing in detail the various adjustments proposed to the Company's test year and rate year operating revenues, Mr. Laflamme reviewed aspects of the Company's corporate restructuring which impacted the calculation of these revenues. As part of the Company's corporate restructuring on January 31, 2011, Mr. Laflamme explained that the legacy KeySpan corporate and utility service companies would be consolidated with National Grid Service Company ("NGSC") to form one service company.[295] In addition to this consolidation, and part of the corporate restructuring, the Company also plans to combine its two financial systems, PeopleSoft and Oracle, into one single ("SAP") system.[296] The Company retained Ernst & Young ("EY") to review costs charged by its

[293] Id., Direct Testimony of Michael D. Laflamme, p.1.
[294] Id., pgs 3-6.
[295] Id., p.13.
[296] Id., p.16.

service companies to Narragansett Electric and Narragansett Gas in the test year to verify that these costs were allocated appropriately, in accordance with National Grid's Cost Allocation Policies and Procedures Manual ("CAM"), and were proper to include in Narragansett Electric's and Narragansett Gas' cost of service.[297] The Company adopted the recommendations of EY to include normalizing adjustments of ($630,168) and $343,088 in the electric and gas cost of service, respectively.[298]

2. __Reallocation of Service Company Costs.__ Mr. Laflamme explained that the new consolidated service company structure would provide benefits of economies of scale and scope and ensure that no operating company is cross-subsidizing another.[299] The new consolidated structure would also improve service quality throughout National Grid because of "job differentiation and specialization that results from providing services on a centralized basis to a number of operating entities."[300] Finally, the new structure would improve reliability by minimizing the use of outside resources and allow for enhanced controls and uniformity of methods and practices.[301]

In anticipation of this consolidation, the Company proposed a revision of its cost allocation methodologies and hired the PA Consulting Group to assist the Company in this endeavor.[302] Based on the PA Consulting Group's recommendations, the Company proposed the adoption of a revised general allocator to be applied when there is no cost causative basis available and a cost causative allocation process which prioritizes the use of direct cause allocation and finally a revised comprehensive cost allocation manual.[303] The revised general

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[297] Id., p.9.
[298] Id., pgs.11-12; M DL-3-ELEC, p.9; MDL-3-GAS, p.9.
[299] Id., p.14.
[300] Id.
[301] Id.,
[302] Id., p.16.
[303] Id., p.16.

allocator, proposed by the Company pursuant to PA's recommendations, is a three (3) factor general allocator that considers gross margin, net plant and O&M expenses, weighted equally.[304] This general allocator is a variation of the most commonly used general allocator known as the Massachusetts Formula. According to PA's research, many jurisdictions have adopted variations of the Massachusetts Formula. PA recommended this particular three (3) factor general allocator for the Company because it was the "best fit" for National Grid USA and because it felt that it would levelize the impact of changing commodity prices and differing degrees to which utility service have been unbundled in various jurisdictions.[305] As a result of the Company's proposed reallocation of test year service company costs, Mr. Laflamme proposed adjustments of $4,514,843 and ($4,452,323) to Narragansett Electric and Narragansett Gas operating expenses.[306]

3. Rate Year Revenue Requirements and Revenue Deficiencies. On behalf of National Grid, Mr. Laflamme requested an electric revenue requirement of $270,471,182.[307] Based on this revenue requirement and projected rate year distribution revenues of $239,022,904, Mr. Laflamme claimed that Narragansett Electric would have a rate year revenue deficiency of $31,448,278.[308] For Narragansett Gas, Mr. Laflamme projected a rate year revenue deficiency of $19,952,203 based on a rate year revenue requirement of $173,128,689 and rate year net distribution revenues of $153,176,486.[309] Both the electric and gas revenue requirements were based on a 10.75% return on equity, as proposed by Mr. Hevert, and the

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304 Id., p.17.
305 Id., p.18; MDL-2, Cost Allocations Review Project Report by The PA Consulting Group, p.55.
306 Id., p.19, 21-22; MDL-3-ELEC, p.48; MDL-3-GAS, p.47.
307 Id., p.6.
308 Id., p.6, 22; MDL-3-ELEC, p.3. The rate year is the twelve month period from February 1, 2013 through January 31, 2014.
309 Id., p.82; MDL-3-GAS, pgs.1-3.

Company's actual capital structure as of December 31, 2011 which consisted of 1.20% short term debt; 49.00% long-term debt; 0.20% preferred equity and 49.60% common equity.[310]

In developing the revenue requirement, Mr. Laflamme began with the revenues and expenses recorded on the Company's books as of December 31, 2011. He then normalized or adjusted these figures by adding or subtracting amounts considered atypical or not likely to occur in the rate year. After applying the normalizing adjustments, Mr. Laflamme further adjusted these revenues and expenses for known and measurable changes to occur in the rate year. The purpose of applying normalizing and pro forma adjustments to test year revenues and expenses is to achieve the best possible estimate of the Company's rate year revenues and expenses in the rate year. Mr. Laflamme proposed normalizing adjustments to the Company's test year electric operating revenues totaling $9,648,547 and pro forma adjustments totaling $3,725,866.[311] Mr. Laflamme proposed normalizing adjustments of ($117,825,347) to the Company's test year electric O&M expenses.[312] He added pro forma adjustments totaling $4,858,292 to test year electric O&M expense which resulted in rate year adjusted O&M expenses of $126,267,434.[313] For each adjustment to operating revenues and expenses, Mr. Laflamme provided a detailed explanation supporting the adjustment and an illustration of how it was derived mathematically. This portion of Mr. Laflamme's testimony, including schedules and workpapers, spans well over five hundred (500) pages. Since this matter was ultimately settled to the satisfaction of the parties, and for brevity, this Order will address only those adjustments to operating revenues or expenses which were of particular concern or importance to the parties.

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[310] Capital structure includes anticipated long-term debt issuance of $150,000,000 and excluded goodwill and other comprehensive income. Id, Direct Testimony of Robert B. Hevert, p.64; RBH-8, p.1.
[311] Id., Direct Testimony of Michael D. Laflamme, p. 24; MDL-3-ELEC, p.5.
[312] Id., p.26; MDL-3-ELEC, p.7,8.
[313] Id.

4. Rate Base. Mr. Laflamme proposed a rate year rate base of $575,087,373 for Narragansett Electric.[314] He first calculated the test year net utility plant in service, including contributions in aid of construction and accumulated depreciation, to be $707,655,322.[315] He then increased the test year net plant by $14,107,422 for materials and supplies, prepayments, loss on reacquired debt and cash working capital and deducted $187,255,531 for ADIT and customer deposits.[316] This yielded an adjusted test year rate base of $534,507,213 which he increased for pro forma adjustments of $40,580,160, resulting in the rate year rate base of $575,087,373.[317]

For Narragansett Gas, Mr. Laflamme proposed a rate year rate base of $369,945,459.[318] His test year net plant for the Company's gas operations was $397,086,429, including contributions in and of construction and accumulated depreciation.[319] To this sum he added materials and supplies, prepaid expenses, deferred Y2K and cash working capital totaling $12,803,289 and subtracted ADIT, customer deposits and a hold harmless adjustment totaling $104,503,206.[320] This yielded an adjusted test year rate base of $305,386,511 which he increased for pro forma adjustments totaling $64,558,947 to arrive at the rate year rate base of $369,945,459.[321]

5. Pension/OPEB Costs and PAM. Mr. Laflamme calculated Narragansett Electric's rate year pension and OPEB expenses to be $13,776,267.[322] To arrive at this figure, Mr. Laflamme began with the Company's test year OPEB expenses of $8,977,300, which he

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314 MDL-3-ELEC, p.63.
315 Test year net plant is a five quarter average of utility plant from December 2010 through December 2011.
316 MDL-3-ELEC. Mr. Laflamme calculated rate year cash working capital of $4,975,475 based on a net lag of 4.81%. Id., Direct Testimony of Michael D. Laflamme, p.76; MDL-4-ELEC.
317 MDL-3-ELEC, p.63.
318 MDL-3-GAS, p.58. Based on a five quarter average from December 2010 through December 2011.
319 Id.
320 Id.
321 Id.
322 Id., MDL-3-ELEC, p.7.

normalized by ($558,792) and further reduced by pro forma adjustments of ($4,876,932), resulting in rate year OPEB expenses of $3,541,576.[323] He then took the Company's test year pension costs of $9,258,180, which he normalized by ($699,569) and then increased by $1,676,080 for pro forma adjustments, resulting in rate year pension costs of $10,234,691.[324] Adding the rate year pension costs ($10,234,691) and rate year OPEB costs ($3,541,576) resulted in total rate year pension/OPEB costs of $13,776,267. These amounts reflect the most recent estimates of rate year pension and OPEB costs provided by the Company's actuary.[325] Mr. Laflamme requested that the Company be allowed to recover this total amount of rate year pension and OPEB costs ($13,776,267) in base rates, and that it be allowed to annually reconcile and recover any discrepancies between this amount and actual pension and OPEB expense pursuant to the pension adjustment mechanism proposed by witnesses Stephen Doucette and Maureen Heaphy.[326] The Company would annually file a pension adjustment factor ("PAF") on August 1 for effect on October 1.[327] The PAF would reconcile pension/OPEB expenses for the previous year ending March 31. Since the new pension adjustment mechanism would not go into effect until February 1, 2013, the first PAF, filed on August 1, 2013, would reconcile the base amount of pension/OPEB expenses with expenses recorded in the two (2) months ending March 31, 2013.[328] In subsequent years, pension/OPEB expenses recorded in the 12 months ending March 31 would be reconciled with the base amount.[329] The Company would recover the reconciled amount over the twelve (12) period from October 1 to September 30.[330] The pension adjustment mechanism would also require the Company to pay a Minimum Funding Obligation

[323] Id.
[324] Id.
[325] Id., p.50.
[326] Id.
[327] Id., p.79.
[328] Id.
[329] Id., p.78.
[330] Id., p.79.

("MFO") which would be the amount collected from customers plus the amount of pension and OPEB costs capitalized.[331] If the Company does not pay the MFO, it would be required to pay a carrying charge at the weighted average cost of capital applied to the cumulative shortfall.[332]

6. Storm Fund. In 2010, the Commission suspended the Company's annual storm fund contributions of $1,041,000 because the storm fund balance was over $20 million; however, Mr. Laflamme reported that since that time, the impact of major storms, including Tropical Storm Irene which caused approximately $34.2 million in storm repair costs, left a storm fund deficit of approximately $11,500,000.[333] Mr. Laflamme proposed rate year storm costs of $3,441,000.[334] This proposal would allow the Company to reinstate annual storm fund collections of $1,041,000 and a temporary three year recovery of $2,400,000 to eliminate the storm fund deficiency of $11,500,000.[335]

7. Property Tax Recovery. Mr. Laflamme claimed that Narragansett Electric's property taxes have been escalating to an inordinate degree.[336] He further claimed that property tax expenses were beyond the control of the Company and have contributed significantly to the Company's inability to earn a reasonable rate of return.[337] In support of this claim, Mr. Laflamme reported Narragansett Electric's tax expenses for years 2008 through 2011 which reflected a three year average annual percentage increase in property tax expense of 11.6%.[338]

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[331] Id., p.80.
[332] Id. The Company also proposed filing an annual reconciliation report, simultaneously with the PAF on August 1, detailing the annual pension and OPEB expense calculation and changing the date of the gas PAM reconciliation period to the 12 month period ending March 31, also to coincide with the electric PAM. Id., p.81.
[333] Id., p.51, 112-113. Annual Storm fund collections were suspended by the Commission pursuant to Order No. 19965A (Docket 4065). The Commission allowed annual Storm Fund collections of $1,041,000 to be reinstated if the Storm Fund balance ever declined below $20 million. Order 19965A (Docket 4065).
[334] Id., p.51; MDL-3-ELEC, p.38.
[335] Id., p.51, 111-115; MDL-3-ELEC, p.38.
[336] Id., p.68.
[337] Id.
[338] Id., p.68. Mr. LaFlamme reported the following property tax expenses: $17,076,089 (2008); $18,625,667 (2009) (9.1% increase); $19,962,667 (2010) (7.2% increase); and $23,658,084 (2011)(18.5% increase). MDL-3-ELEC, p.59.

To address this problem, Mr. Laflamme proposed that Narragansett Electric be allowed to include and recover in base rates property tax expenses of $29,743,324.[339] Mr. Laflamme arrived at this figure by multiplying the average annual percentage increase of 11.6% for years 2008-2011 by Narragansett Electric's normalized test year property tax expense through the end of the rate year.[340] For Narragansett Gas, the three year average annual percentage increase for years 2008-2011 was 9.1%.[341] Mr. Laflamme applied this rate to Narragansett Gas' normalized test year property tax expense to arrive at a rate year property tax expense of $13,994,652.[342]

Mr. Laflamme conceded that rising property tax rates did not constitute the sole factor contributing to the Company's under recovery of property tax expense. He admitted that increased plant investments also contributed to the Company's increase in property tax expense and under recovery of this expense but did not explain how this concession factored into his proposal for a property tax reconciliation mechanism.[343] Mr. Laflamme proposed that the Company be allowed to annually reconcile the amount of property tax expense included in base rates for its gas and electric operations (which amount would be based on a three year average increase of property tax expense) to actual property tax expense through a separate rate adjustment mechanism.[344] According to his proposal, the property tax reconciliation mechanism would operate similar to the proposed pension adjustment mechanism. The proposed reconciliation factor would be filed annually on August 1.[345] The reconciliation period would be the prior fiscal year which runs from April 1 through March 31, except for the first year which

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[339] Id., p.68.
[340] Id., p.68. Mr. Laflamme "grossed up" tax expenses through the end of the rate year by multiplying each year by 1 + 11.6%, or 1.116. MDL-3-ELEC, p.59.
[341] MDL-3-GAS, p.54.
[342] Id.
[343] Id., pgs.118-119
[344] Id., p.116.
[345] Id., p.120.

would cover the two months ending March 31, 2013.[346] The Company would collect/credit the over or under recovery during the twelve month period that begins on October 1 for electric and November 1 for gas.[347]

Uncollectible Accounts. Mr. Laflamme addressed Evelyn Kaye's testimony and the anticipated increase in the Company's rate year level of uncollectible rate due to previously mentioned factors such as economic conditions and regulatory environment. Mr. Laflamme applied the three year net write-off rate of 1.35% proposed by Ms. Kaye to the rate year base revenue which resulted in an allowed base rate bad debt expense, for electric operations, totaling $3,264,875.[348] This amount is $38,924 greater than the bad debt cost in the test year.[349] For bad debt associated with energy efficiency, Mr. Laflamme proposed collecting this portion of bad debt outside of base rates through the energy efficiency charge.[350] Using the proposed net write off rate of 1.35%, Mr. Laflamme proposed recovering efficiency related bad debt expense of $659,464 through the energy efficiency charge.[351] For the Company's gas operations, Mr. Laflamme applied the three year net write off rate of 3.79% proposed by Ms. Kaye to rate year base rate revenue and calculated an allowed base rate bad debt expense of $5,245,371.[352] This amount was $1,854,662 greater than the bad debt expense in the test year.[353]

Consumer Advocates. To cover the expense of the two consumer advocates proposed by witness Evelyn Kaye, Mr. Laflamme recommended an expense adjustment of $166,282 for the Company's electric operations.[354] This expense assumed a base salary of $92,744 for each

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[346] Id.
[347] Id.
[348] Id., p.57.
[349] Id.
[350] Id., p.58.
[351] Id.
[352] Id., p.100.
[353] Id.
[354] Id., p.56.

employee plus benefits.[355] For Narragansett Gas, Mr. Laflamme proposed an adjustment of $164,763.[356]

K. Direct Testimony of Howard S. Gorman- ACOSS (Electric)

Howard S. Gorman presented the Allocated Cost of Service Study ("ACOSS") for the Company's electric revenue requirement. Mr. Gorman analyzed how each element of the electric revenue requirement ($270,471,000) should be allocated among the rate classes.[357] He described his analysis as a three step process which involved, in consecutive order, the functionalization, classification and allocation of each element of the revenue requirement.[358] In the first step, elements were categorized or "functionalized" according to the area or portion of the electrical system involved. Mr. Gorman functionalized elements into one of four categories--sub-transmission, primary distribution, secondary distribution or billing.[359] Mr. Gorman then classified the functionalized elements into one of three categories—Demand, Energy or Customer, depending on the system design or operating characteristics that caused them to be incurred.[360] Some costs were divided between the Demand and Customer categories.[361] Finally, functionalized, classified costs were allocated among the rate classes according to how each cost was caused.[362] Causal relationships were determined by analyzing the Company's system design and operations, accounting records and system and customer load data.[363]

According to Mr. Gorman's ACOSS, the electric revenue requirement of $270,471,000 would be allocated among the rate classes in the rate year as follows: Residential A-16/A-60

[355] Id., p.55; MDL-3-ELEC, p.44.
[356] Id., p.98; MDL-3-GAS, p.42.
[357] Id., Direct Testimony of Howard S. Gorman, p.3.
[358] Id.
[359] Id.
[360] Id., p.3, 13.
[361] Id., p.13.
[362] Id., p.15.
[363] Id., p.15.

($142,322,000); Small C&I C-06 ($26,492,000); General C&I G-02 ($39,877,000); C&I 200 kW Demand G-32 and C&I 200 kW Demand Backup ($36,405,000); C&I 3000 kW Demand G-62 ($9,014,000); Street Lighting S-10/S-14($15,623,000); Propulsion ($739,000).[364] Mr. Gorman then calculated the revenue increase for each rate class by comparing the rate year class revenue requirements to the current rate class revenue requirements. This comparison revealed the following revenue increases, expressed in dollars and percentages, for each class: Residential A-16/A-60 ($19,252,000 or 15.64%); Small C&I C-06 ($978,000 or 3.83%); General C&I G-02 ($1,201,000 or 3.10%); C&I 200 kW Demand G-32 and C&I 200 kW Demand Backup ($1,089,000 or 3.08%); C&I 3000 kW Demand G-62 ($3,487,000 or 63.10%); Streetlighting S-10/S-14 ($5,197,000 or 49.85%); Propulsion ($245,000 or 49.64%).[365]

L. <u>Direct Testimony of Jeanne A. Lloyd- Revenue Allocation, Rate Design and Tariffs (Electric)</u>

Jeanne A. Lloyd proposed the rate design and tariff revisions to support Mr. Gorman's ACOSS. She also discussed the bill impacts associated with her proposal as well as the storm cost recovery factor. In designing rates, Ms. Lloyd attempted to reflect the results of the ACOSS as closely as possible while attempting to mitigate extreme impacts on rate classes and customer subgroups.[366] Ms. Lloyd claimed that the Company's proposed revenue allocation was aligned with the respective cost of service for each rate class and that it would avoid extreme rate impacts.[367] She testified that Mr. Gorman's ACOSS would result in the following percentage revenue increases by rate class:[368]

A-16/A-60 (Residential and Low Income)……….……………………..……15.6%

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[364] Id., HSG-1A. The A-16 and A-60 class were combined for purposes of Mr. Gorman's ACOSS. Id., Direct Testimony of Howard S. Gorman, p.4.
[365] Id., HSG-1A.
[366] Id., Direct Testimony of Jeanne A. Lloyd, p.4.
[367] Id., pgs.9-10.
[368] Id., p.5.

C-06 (Small C&I)……………………………………………………….3.8%

G-02 (General C&I)……………………………………………………3.1%

B/G-32 (200kW Demand Rate)…………………………….………..3.1%

B/G-62 (3,000 kW Demand Rate)…………………………………..63.1%

S-10/S-14 (Street and Area Lighting)……………………………….49.8%

X-01 (Electric Propulsion)……………………………………………49.6%

The average increase in base distribution revenue needed to produce the proposed system average rate of return of 7.85% is approximately 13.2%.[369] She calculated the increase necessary to produce the system average rate of return of 7.85% and then limited the increases for 3 classes at twice the system average, or 26.3%.[370] The limits were applied to the following three rate classes: 3,000 kW Rate Class (B/G-62); Electric Propulsion Rate Class (X-01); and the Streetlighting Rate Classes (S-10/S-14).[371] Ms. Lloyd allocated the subsidy for the Residential Low Income Rate Class (A-60) to all customers based on the respective rate class revenue requirements.[372] Limiting the increase for the three rate classes noted above resulted in a revenue shortfall of $5.2 million.[373] Ms. Lloyd re-allocated this shortfall to the remaining rate classes according to the respective rate class revenue requirements.[374] These adjustments resulted in the following percentage increases by rate class:[375]

A-16/A-60 (Residential and Low Income)…….……..……….…….…15.5%

C-06 (Small C&I)…………………………………………..…...….8.6%

G-02 (General C&I)……………………………………………………..7.9%

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[369] Id., p.8; JAL-1, p.1.
[370] Id., p.8.
[371] Id.
[372] Id.
[373] Id.
[374] Id., p.9. The revenue requirements were adjusted for the A-60 discount.
[375] Id.

B/G-32 (200kW Demand Rate)…………………………………….…...7.9%

B/G-62 (3,000 kW Demand Rate)………………………….….……..26.3%

S-10/S-14 (Street and Area Lighting)……………….………….…..…26.3%

X-01 (Electric Propulsion)………………………………..……..…26.3%

Ms. Lloyd reviewed each rate class to determine how to best achieve the revenue allocation proposed by Mr. Gorman without causing an extreme rate increase in any one class. She first looked at the customer charge for each rate class to determine whether it was appropriately aligned with the costs to serve that rate class.[376] She then reviewed the energy based and demand based rate.[377] Her analysis resulted in the following revisions.

Currently, the non low-income residential rate (A-16) includes a customer charge and an energy charge, while the low income residential rate (A-60) includes only an energy charge.[378] The current rate is designed so that an A-60 customer is billed approximately 50% of the amount that an A-16 customer is billed.[379] Ms. Lloyd proposed implementing a monthly customer charge of $1.00 in the low income rate (A-60) and increasing the A-16 monthly customer charge from $3.75 to $5.00.[380] Ms. Lloyd claimed these revisions would improve the stability and predictability of costs for customers and revenues for the Company and more accurately reflect the customer related portion of costs.[381] She claimed that her proposed customer charges for the residential class were "well below" the revenue requirement for customer related costs of $7.87 per month for the combined class.[382]

Ms. Lloyd proposed increasing the customer charge for the C-06 class from

[376] Id., p.12-24.
[377] Id.
[378] Id., pgs.11-12.
[379] Id., p.12.
[380] Id.
[381] Id.
[382] Id; HSG-1C, p.1.

$8.00 per month to $10.00 per month which would still be below the unitized revenue requirement for customer related costs of $11.39 per month for the class.[383] She proposed increasing the customer charge for unmetered customers (telephone booths and fire box lights) to $6.00 which she claimed would approximately equal the class average increase.[384] She indicated that the Company may require customers with a 12-month average demand exceeding 200 kW to take service on the G-32 rate.[385] The monthly kilowatt-hour charge for the C-06 class would increase to $0.03398.[386]

Ms. Lloyd reviewed the current rate design for G-02. This class (like the G-32 class) has a monthly customer charge, an energy based charge and a demand based charge.[387] She proposed increasing the customer charge for the G-02 class from $125.00 per month to $135.00 per month.[388] The monthly kilowatt-hour charge would increase to $0.00501, and the monthly demand charge for the G-02 class would increase from $4.78 to $5.50 per kW for each kW in excess of 10 kW.[389]

The G-32 rate class is required for customers with a maximum 12-month demand of 200 kW or greater for three consecutive months.[390] The G-32 rate class includes a monthly customer charge, an energy based charge and a demand-based charge for kWs in excess of 200 kW.[391] The G-62 rate class is required for customers with a maximum 12-month demand exceeding 3,000 kW.[392] The G-62 rate includes a monthly customer charge and a

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383 Id., p.13.
384 Id.
385 Id., p.13. The Company may also require G-02 customers (10 kW Demand) with a 12-month average demand exceeding 200 kW to take service on the G-32 rate. Id., p.14.
386 JAL-4, p.3.
387 Id., p.14.
388 Id., pg.14-15.
389 Id., p.15; JAL-4, p.4.
390 Id., p.16.
391 Id.
392 Id.

demand-based charge.[393] The G-32 and G-62 classes have companion back-up rates, in addition to their monthly customer charges.[394] Ms. Lloyd proposed increasing the customer charge for the G-32 class from $750.00 to $825.00.[395] She claimed the increased charge of $825.00 would be closer to the cost "for the functions included."[396] The monthly demand charge for the G-32 class would increase from $2.29/kW to $3.75/kW for each kW in excess of 200 kW.[397] The energy based charge for the G-32 and B-32 class would increase to $0.00596.[398]

Ms. Lloyd did not propose an increase in the G-62 customer charge since the cost to serve this class ($2,646.78) is already much lower than the current customer charge of $17,000.00.[399] She did, however, propose a tariff revision for the G-62 class. Specifically, she propose revising the availability of the B/G-62 rate from mandatory for all customers with a maximum annual demand in excess of 3,000kW to optional for customers with a maximum annual demand in excess of 5,000kW.[400] She also proposed a change to the G-62 tariff which would allow smaller customers (demands between 3,000 kW and 5,000 kW) to transfer to the G-32 rate.[401] This change would serve the dual purpose of aligning larger G-62 customers to their customer related cost without creating extreme hardship on smaller G-62 customers.[402] The G-32 rate was adjusted to address anticipated lost revenue resulting from the inevitable migration from the G-62 to the G-32 rate class (due to the revised availability of the G-32).[403] Ms. Lloyd explained that without the rate increase for the G-32 class, the lost revenue resulting from the

[393] Id.
[394] Back up rates are available to customers who generate some or all of their own electricity. Id.
[395] Id., p.17
[396] Id.
[397] Id.
[398] JAL-4, p.5.
[399] Id., p.18; HSG-1C, p.1.
[400] Id., p.18.
[401] Id., p.19.
[402] Id.
[403] Id.

migration would be recovered from all customers through the revenue decoupling mechanism.[404] To clearly reflect these changes in the tariffs, Ms. Lloyd revised the language of the relevant tariff provisions and changed the names of the B/G tariffs to Large Demand Rate G-32, Optional Large Demand Rate G-62, Large Demand Back-up Service Rate B-32 and Optional Large Demand Back-up Service Rate B-62.[405] She did not propose a change to back-up rates.[406]

Ms. Lloyd reviewed the X-01 rate which is the rate for electricity supplied to railroads. Currently, the X-01 rate class has a monthly customer charge and an energy based charge.[407] As previously discussed, Ms. Lloyd limited the revenue increase for the X-01 class to 26.3% (twice the system average of 13.2%) in order to collect the Company's electric revenue requirement of $270,471,000. Accordingly, Ms. Lloyd proposed increasing the customer charge for the X-01 class from $16,500.00 to $21,000.00 per month and increasing the energy based charge to $0.01562/kWh.[408]

The M-01 rate class consists of merchant generators interconnected with high voltage facilities of 115 kV or greater.[409] To ensure a revenue increase of 13.2% for the M-01 class, Ms. Lloyd proposed increasing the customer charge for the M-01 class from $3,640.42 to $4,119.41.[410]

The Street Lighting rate classes consist of the S-06 or Decorative Street and Area Lighting class; the S-10 or Private Lighting class; and the S-14 or General Street and Area Lighting class. The S-06 class is available to any customer, and the S-14 is available only to

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[404] Id.
[405] Id., pgs.20-21, JAL-7, JAL-8.
[406] Id., p.20.
[407] Id., Direct Testimony of Jeanne A. Lloyd, p. 21.
[408] Id., p.21, JAL-4, p.7.
[409] Id., p.22.
[410] JAL-4, p.11.

municipalities, public entities and other customers designated by tariff.[411] The street lighting rates consist of a monthly charge based on the type and size of the luminaire and support (pole and attachments) and a kilowatt-hour charge that reflects the operations and maintenance credit approved in the Company's 2012 Infrastructure, Safety and Reliability Plan.[412] To achieve the proposed 26.3% increase for the S-10/14 class, Ms. Lloyd set rates at 64.4% of the levelized annual costs of the luminaires and supports.[413]

Transmission Charge. Ms. Lloyd proposed a change in the Company's method of allocating transmission rates. Transmission charges are currently based on a forecast which is developed from actual load data from the previous year.[414] The transmission charge, based on this forecast, is allocated to each rate class based on its contribution to New England Power's monthly peak.[415] The billed transmission charges collected by the Company are then reconciled each year to actual transmission expenses incurred.[416] Ms. Lloyd proposed changing the method of allocating the transmission charge to the various rate classes to be consistent with Mr. Gorman's allocated cost of service study. Instead of allocating the transmission charge based on the prior year's peak load, Ms. Lloyd proposed allocating the transmission charge based on average load factors for the years ending 2008 and 2011 and applying this to the normalized kilowatt-hour sales levels for the upcoming year.[417] She also proposed that the transmission adjustment factor used to reconcile the transmission charge be class specific, as opposed to the current uniform per kWh charge.[418] This means the transmission adjustment factor would be

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[411] Id., p.22.
[412] Id., p.23.
[413] Id.
[414] Id., p.26.
[415] Id.
[416] Id.
[417] Id.
[418] Id.

calculated by allocating actual transmission expense during the reconciliation period based on each rate class' contribution to system peak during the twelve month reconciliation period.[419]

Energy Efficiency Program ("EEP") Charge. Ms. Lloyd proposed adjusting the EEP charge to include an allowance for the Company's proposed uncollectible accounts receivables associated with amounts billed through the EEP charge. The EEP charge would be adjusted by 1.35% to be consistent with the Company's proposal, presented by Evelyn Kaye, to establish an uncollectible net write off rate for electric distribution services of 1.35%.[420] Ms. Lloyd noted that the gas EEP charge currently includes an adjustment for uncollectible accounts expense.[421]

Standard Offer Adjustment Provision ("SOAP"). Ms. Lloyd explained that the method of calculating the annual SOAP would be adjusted to reflect Ms. Kaye's proposal to establish an uncollectible net write off rate of 1.35% and reconcile any differences between its actual, commodity related net write-offs and revenues derived from the proposed net write-off rates of 1.35%.[422]

Storm Cost Recovery Factor. Ms. Lloyd explained her calculation of the storm cost recovery factor proposed by Mr. Laflamme to cure the $7.2 million deficient in the Storm Fund. According to Mr. Laflamme's proposal, the Company would recover the storm deficit of $7.2 million over a three year period. In order to accomplish this, Ms. Lloyd divided $7.2 million by the forecasted kilowatt-hour deliveries during the three year period from the effective date of the rate increase, February 1, 2013 through January 31, 2016. This results in a storm cost recovery

[419] Id., pgs. 26-27.
[420] Id., pgs. 27-28.
[421] Id., p.28.
[422] Id.

factor of \$0.00030/kWh which would be included in the distribution kWh charge, applicable to all customers, effective February 1, 2013.[423]

Bill Impacts. Ms. Lloyd reported the bill impacts associated with the Company's proposed electric distribution rate increase. Unless otherwise stated, all bill impacts were calculated on a monthly basis. In calculating the bill impacts, Ms. Lloyd adjusted the distribution energy charge for each rate class to reflect an estimated revenue decoupling credit of \$0.00077/kWh.[424] According to Ms. Lloyd's analysis, the proposed electric distribution rate increase would cause an average residential customer's bill would increase by \$3.97 or 5.1%.[425] A typical A-60 or low income residential customer's bill would increase by \$2.44 or 3.6%.[426] Ms. Lloyd calculated the following bill increases for the commercial and industrial rate classes:[427]

C-06 (1,000 kWh)………………………….....…..... \$4.60 (3.0%)
G-02 (20,000 kWh/100 hrs)……………………..……\$84.36 (2.9%)
G-02 (30,000 kWh/300 hrs)……………………….\$87.60 (2.2%)
G-02 (40,000 kWh/400 hrs)……………………..…\$90.83 (1.8%)
G-02 (50,000 kWh/500 hrs)……………………..…\$94.05 (1.5%)
G-02 (60,000 kWh/600 hrs)………………………. \$97.28 (1.4%)
G-32 (200,000 kWh/200 hrs)……………………..\$1,140.62 (5.7%)
G-32 (300,000 kWh/300 hrs)……………………..\$1,063.54 (4.0%)
G-32 (600,000 kWh/400 hrs)……………………..\$1,592.70 (3.1%)
G-32 (750,000 kWh/500 hrs)……………………..\$1,477.08 (2.4%)
G-32 (900,000 kWh/600 hrs)……………………..\$1,361.45 (1.9%)
G-62 (1,500,000 kWh/200 hrs)…………………...\$9,671.87 (6.2%)
G-62 (2,250,000 kWh/300 hrs)…………………\$10,757.82 (5.3%)
G-62 (3,000,000 kWh/400 hrs)…………………\$11,843.75 (4.8%)
G-62(3,750,000 kWh/500 hrs)…………………..\$12,929.69 (4.4%)
G-62 (4,500,000 kWh/600 hrs)……………….…\$14,015.62 (4.1%)

423 Id., p.29.
424 Id., p.29.
425 Id., JAL-6, p.1. The Company defines "average residential customer" as a customer consuming 500 kWh per month. National Grid 1, Direct Testimony of Jeanne A. Lloyd, p. 29.
426 JAL-6, p.2.
427 JAL-6, pgs.3-18.

For the street lighting classes, Ms. Lloyd presented the bill impacts for each individual luminaire on an annual basis.[428] Her analysis was based on the assumption that a customer could be served by only one street lighting fixture.[429] Depending on the luminaire type, bill impacts ranged from \$0.83/year (0.5%) to \$339.51/year (183%).[430] She reported zero impact for some fixtures.[431]

M. Direct Testimony of Paul M. Normand- ACOSS (Gas)

Paul M. Normand presented the ACOSS and rate design for National Grid's gas operations. Mr. Normand is a management consultant and President of Management Applications Consulting, Inc.[432] Mr. Normand determined the class revenue requirements needed to produce an equalized rate of return of 8.24%.[433] Mr. Normand reviewed the percentage increases necessitated by these revenue requirements and then adjusted these revenue targets in effort to produce lower and more evenly distributed rate increases. Specifically, Mr. Normand capped the revenue increase for the Residential Non-Heating and Large HLF C& I rate classes at 15.26% which was the overall percentage increase proposed by the Company.[434] He then allocated the shortfall produced by this cap to the uncapped, larger rate classes using a fixed factor applied to test year base revenues at uniform equalized revenue levels.[435] Mr. Normand noted that his methodology of capping revenue increases for certain rate classes is a well-accepted practice used in utility ratemaking for the purpose of promoting gradualism and mitigating rate shock.[436] After capping the Residential Non-Heating and Large HLF C& I

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[428] JAL-6, p.19.
[429] National Grid 1, Direct Testimony of Jeanne A. Lloyd, p.32.
[430] JAL-6, p.19.
[431] Id.
[432] National Grid 1, Direct Testimony of Paul M. Normand, p.1, PMN-1.
[433] National Grid 1, Direct Testimony of Paul M. Normand, p.17.
[434] Id., p.18.
[435] Id., p.19.
[436] Id.

classes and allocating the resulting shortfall to the remaining uncapped classes as noted above, Mr. Normand proposed the following percentage increases for each rate class:[437]

Residential Non-Heat……………………………………………...…….. 15.23%
Residential Heat…………………………………….………………… 14.75%
Small C&I…………………………………………………………… 11.31%
Medium C&I…………………………………………………………. 9.32%
Large C&I LLF……………………………………………….…… 9.39%
Large C&I HLF…………………………………………………..… 15.24%
Extra Large C&I LLF……………………………………………….. 8.76%
Extra Large C&I HLF……………………………………………… 9.16%

In establishing the rates for the various rate classes, Mr. Normand used a four-step process. After establishing the revenue targets for each rate class (1), he then determined the rate structure using the existing structure approved in the last rate case (Docket No. 3943) (2). He then established the customer charge for each rate class (3) and finally, he determined the residual class revenue requirements and any applicable heard or block pricing (4).

Mr. Normand attempted to align customer charges with ACOSS levels; however, in order to achieve a more equitable class recovery responsibility, Mr. Normand noted that significant increases were necessary for the Residential and Small C&I classes since they had a very deficient level of fixed customer cost recovery.[438] Accordingly, Mr. Normand proposed the following customer charges:[439]

Residential Non-Heat………………………..…………….……….…… $12.50[440]
Residential Heat…………………………………………………….... $15.00
Small C&I…………………………………………………………… $23.25
Medium C&I………………………………………………………… $70.00

[437] Id., p.20.
[438] Id., p.21.
[439] Id.
[440] The customer charge that Mr. Normand proposed for the Residential and Small C&I classes was an increase of 125% from the existing customer charge for these rate classes. Id.

Large C&I LLF………………………………………………………….. $175.00

Large C&I HLF……………………………………………..…….. $175.00

Extra Large C&I LLF………………………………………………… $425.00

Extra Large C&I HLF……………………………………………….. $425.00

Mr. Normand proposed increasing all demand rates by 13.27% which is the Company's overall revenue increase request.[441] He determined the rates for each class by subtracting the revenue derived from the customer charge and demand rate and then dividing this residual target revenue by the appropriate level of sales (therms) for each rate class.[442] His final proposed rates are listed below.[443]

Residential Non-Heat……………………………………………………… $0.5009

Residential Low Income Non-Heat ………………………………………. $0.4508

Residential Heat …..…………………………………………..…. $0.4776/$0.3076[444]

Residential Low Income Heat ………………………………….. $0.4298/$0.2768[445]

Small C&I…………………………….................................... $0.5696/$0.2351[446]

Medium C&I………………………………………………..………. $0.2023

Large C&I LLF……………………………………………….………. $0.1846

Large C&I HLF………………………………………………….……… $0.1109

Extra Large C&I LLF…………………………………………….….….. $0.0362

Extra Large C&I HLF……………………………………………….…..…. $0.0295

Finally, Mr. Normand provided a bill impact analysis showing the effect of his proposed rate increases on each rate class. Mr. Normand's bill impacts, presented below, represent the approximate increase, in dollars and percentages, in the annual gas bill for "average" customers. The Company defines average customers in terms of annual consumption levels. For instances,

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[441] Id.
[442] Id., pgs.22-23.
[443] PMN-7, p.3. Rates are per Therm.
[444] The proposed Residential Heating Rate was $0.4776/therm for the first 125 therms consumed during the billing cycle and $0.3076/therm for consumption over and above 125 therms. PMN-7, p.3; AEL-4, p.68.
[445] The proposed Residential Low Income Heating rate was $0.4298 for the first 125 therms consumed during the billing cycle and $0.2768 for consumption above 125 therms. PMN-7, p.3; AEL-4, p.70.
[446] $0.5696/therm for the first 135 therms consumed during the billing cycle and $0.2351/therm for consumption over 125 therms. PMN-7, p.3; AEL-4, p.72.

an average residential heating customer consumes 922 therms per year.[447] Average consumption levels of other rate classes are appropriately footnoted below.

Residential Heat …..…………………………………………………. $98.00 (7.6%)

Residential Low Income Heat ……………………………………..…… $86.00 (6.9%)

Residential Non-Heat………………………………………..…….. $30.00 (8.2%)[448]

Residential Non-Heat Low Income…………………………..……… $26.00 (7.5%)[449]

Small C&I……………………………... $109.00 (5.9%)[450]

Medium C&I…………………………………………………..…….. $539.00 (4.2%)[451]

Large C&I LLF……………………………………………..……….. $2,394 (3.7%)[452]

Large C&I HLF……………………………………………..………. $2,421 (4.2%)[453]

Extra Large C&I LLF……………………………………..……… $6,604 (2.3%)[454]

Extra Large C&I HLF……………………………………..……… $7,735 (2.9%)[455]

N. Direct Testimony of Ann E. Leary- Test Year Adjustments and Tariffs (Gas)

Ann E. Leary, Manager of Gas Pricing for National Grid Corporate Services LLC., explained the adjustments to test year and rate year revenues, as well as the tariff revisions associated with the Company's proposed gas distribution rate increase. Ms. Leary explained that test year revenues were normalized for weather using Mr. Silvestrini's analyses and forecasts. The purpose of weatherization adjustments is to ensure that test year revenues reflect any differences between the test year and a historical normal.[456] Because gas consumption is heavily impacted by weather (cold weather triggers higher consumption), weatherizing adjustments are an important aspect of determining test year and rate year revenues. Ms. Leary also explained

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447 PMN-8, p.1.
448 Based on annual consumption of 189 therms. PMN-8, p.2.
449 Based on annual consumption of 189 therms. Id.
450 Based on annual consumption of 1,269 therms. Id., p. 3.
451 Based on annual consumption of 10,950 therms. Id.
452 Based on annual consumption of 57,742. Id., p.4.
453 Based on annual consumption of 58,418 therms. Id.
454 Based on annual consumption of 291,462 therms. Id., p. 5.
455 Based on annual consumption of 284,094 therms. Id.
456 National Grid 1, Direct Testimony of Ann E. Leary, p.3.

how rate year revenues were adjusted to reflect anticipated ISR and RDM revenue adjustments.[457] She explained that the post-test year ISR adjustment represents the variance between the ISR revenue collected during calendar year 2011 and the revenue requirement associated with fiscal year 2013 capital investment plan approved in Docket 4306 projected to be collected in the rate year.[458] Similarly, the RDM adjustment was calculated as the variance between the forecasted revenue per customer for residential, small and medium commercial and industrial customers for the rate year and the revenue per customer benchmarks approved in Docket 4206.[459] The Company calculated the RDM adjustment by multiplying the projected rate year number of customers by the variance between the projected rate year revenue per customer and the revenue per customer benchmark approved in Docket 4206.[460]

Ms. Leary provided the tariff changes necessitated by the proposed rate increase. She revised the gas distribution tariffs to reflect the proposed new rates and revised the Company's Gas Cost Recovery ("GCR"), Distribution Adjustment Clause ("DAC") and Other Miscellaneous Charges tariffs. She revised the GCR tariff to include a true-up mechanism for commodity related bad debt and simplified the procedure for processing gas supply refunds.[461] Similarly, Ms. Leary revised the DAC tariff to incorporate the Company's proposals regarding the dual fuel customer tracking mechanism, property tax recovery and to include non-substantive drafting

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[457] Id., p.5. Each year the Company files an ISR Plan (Infrastructure, Safety and Reliability) pursuant to R.I.G.L. §39-1-27.7.1(c)(2) which is a proposed budget for capital investments anticipated in the upcoming fiscal year. The Company includes the approved ISR budget in base distribution revenues. The approved budget or revenue requirement is allocated among the different rate classes through a rate base allocator developed by the Company in accordance with cost of service principles. Each year the amount of billed revenues generated from the rate base allocator is reconciled to the amount of the revenue requirement approved in the prior year. The gas and electric ISR Plans are filed separately on or before January 1 for effect during the upcoming fiscal year, or the twelve month period from April 1 to March 31.

The Company files a Revenue Decoupling Adjustment ("RDA") Factor on July 1 each year for effect on November 1. The RDA Factor reconciles the actual base revenue per customer by rate class with the target revenue per customer approved in Docket 4206. The revenue decoupling mechanism is mandated by R.I.G.L. §39-1-27.7.1.

[458] Id.

[459] Id., p.6.

[460] Id.

[461] AEL-4, pgs.40-41.

revisions.[462] Specifically, Ms. Leary's DAC tariff revisions reflect the Company's proposal to reconcile revenues from only the non-firm dual fuel customer margins, rather than from both firm and non-firm customers, per the Company's existing practice which was approved in Docket 3943, and to change the margin from $2.8 million to $1.5 million.[463] Ms. Leary also eliminated provisions which have become obsolete since the implementation of revenue decoupling and the annual infrastructure, safety and reliability filing.[464] Finally, Ms. Leary provided the tariff revision associated with the paperless billing proposed by the Company's witness, Jeffrey Martin.[465]

III. <u>Direct Testimony of the Division of Public Utilities and Carriers</u>

On August 30, 2012, the Division of Public Utilities and Carriers ("Division") filed Direct Testimony in reference to the Company's April 27 application for an increase in electric and gas base distribution rates. The Division's August 30 filing consisted of direct testimony from the following witnesses:

1. David J. Effron;
2. Mathew I. Kahal;
3. Bruce R. Oliver;
4. Lee Smith;
5. Dr. Emma L. Nicholson; and,
6. Bruce A. Gay.

A. <u>Direct Testimony of David J. Effron</u>

[462] AEL-4, pgs.43-63.
[463] National Grid 1, Direct Testimony of Ann E. Leary, pgs.8-9.
[464] The following provisions were eliminated from the DAC tariff: the weather normalization factor, the accelerated replacement program ("ARP"), the capital tracker and the lost revenue factor. Id., p.10.
[465] AEL-4, p.145.

David J. Effron is a utility consultant hired by the Division of Public Utilities and Carriers ("Division") to review the rate application filed by National Grid. Mr. Effron's pre-filed testimony addressed the electric and gas revenue requirements proposed by National Grid; the fully reconciling mechanism for commodity related bad debt; the fully reconciling mechanism for property tax expense; and the proposed PAM. Based on his analysis, Mr. Effron calculated an electric revenue requirement of $246,766,000 and an electric revenue deficiency of $15,890,000.[466] Mr. Effron arrived at this revenue requirement by making numerous adjustments to the Company's rate year cost of service and rate base. According to Mr. Effron's analysis, the Company had a rate year cost of service of $254,724,000, instead of $270,471,000 which was proposed by the National Grid.[467]

1. <u>Mr. Effron's Adjustments to Electric Revenue Requirement</u>

Mr. Effron reduced the pro forma variable pay adjustment by $400,000 to reflect two miscalculations that the Company made regarding the variable pay and Union Goals adjustment.[468] The Company miscalculated the uninsured claims expense which resulted in a further reduction of $1,021,000 to the cost of service.[469] Mr. Effron eliminated the Company's pro forma adjustment for O&M expenses related to capital spending totaling $849,000 based on his review of the Company's discovery responses which revealed that rate year capital spending would not be likely to increase from $48,613,000 to $56,540,000 as alleged by the Company. In particular, Mr. Effron questioned the Company's estimate that the average amount of O&M related to capital spending was 10.71% for the fiscal period from 2009 through 2011. The Company multiplied this percentage by the difference between test year and rate year capital

[466] Division 89, Direct Testimony of David J. Effron, pgs.3-4.
[467] Id., p.6; DJE-E-2.
[468] Id., p.6; Division 1, National Grid's Response to Division 1-7-ELEC.
[469] Division 90, Direct Testimony of David J. Effron, p.7; Division 2, National Grid's Response to Division 1-20-ELEC.

spending. Mr. Effron felt this method of calculating the pro forma adjustment for operation and maintenance was improper since the large majority of National Grid's capital spending each year related to only a small number of capital projects. Mr. Effron reasoned that the Company's O&M expenses related to capital spending in any given year was project specific, yet the Company had not provided any evidence that O&M expenses related to specific projects would increase in the rate year.[470]

Mr. Effron removed the Company's customer outreach and education expense of $521,000 from the rate year cost of service which had been included by the Company for the purpose of improving the delivery of communications with customers on issues of safety, storm, preparedness, energy efficiency and the benefits of natural gas, billing information and financial assistance.[471] Mr. Effron removed the $521,000 from cost of service on the basis that the Company had not proven this expense would improve the effectiveness of communications or that the benefits of increased communication were commensurate with the expense.[472] He removed from cost of service the two Consumer Advocate positions totaling $158,000, claiming the Company had not shown these positions were necessary or that it was appropriate for the Company to serve as consumer advocates in public benefit programs.[473] He also removed from cost of service $240,000 which the Company had included for the purpose of hiring 26 new employees in October of 2012 as part of the U.S. Foundation Project.[474] Mr. Effron felt it was inappropriate to include the expense of hiring new employees before some of the employees had been hired.[475]

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[470] Division 90, Direct Testimony of David J. Effron, pgs 8-9.
[471] Id., pgs. 9-10, quoting Direct Testimony of Michael Laflamme, p. 52-53.
[472] Id., p.11.
[473] Id., p.12.
[474] Michael Laflamme discusses the Company's plan to hire 26 employees for the US Foundations Project at pgs. 56-57 of his Direct Testimony.
[475] Division 90, Direct Testimony of David J. Effron, p.13.

Mr. Effron calculated an uncollectible accounts expense of $2,720,000 as compared to the Company's pro forma uncollectible accounts expense of $2,975,632.[476] Mr. Effron's uncollectible accounts expense was based on a grossed-up bad debt write off rate of 0.929% proposed by Division witness, Bruce A. Gay.[477] Mr. Effron also opposed the Company's proposal to implement a fully reconciling mechanism for commodity-related bad debt to recover its commodity-related uncollectible accounts expense. Mr. Effron expressed the view that reconciliation mechanisms are contrary to sound ratemaking practice and tend to reduce or eliminate incentives to control costs authorized under standard ratemaking.[478] He further noted that the Company had not claimed potential financial impairment due to increases in uncollectible accounts, nor had it compared the magnitude or volatility of uncollectible accounts expense visa vie other costs for which there is no reconciliation mechanism.[479] Mr. Effron referred to Mr. Gay's criticisms of the Company's current collections practices, expressing the concern that a fully reconciling mechanism for commodity related bad debt would diminish the Company's incentive to improve its revenue recovery practices.[480] Mr. Effron recommended that the Commission reject the Company's proposal for a commodity-related bad debt reconciling mechanism since it had not proven it was necessary to protect its financial integrity.[481] He argued that the present method of recovering bad debt holds the Company harmless from changes in bad debt caused by circumstances that are beyond the Company's control, and the Company had not provided a basis for allowing it to recovery changes in the net write-offs as a percentage of commodity revenues, especially where such changes were within

[476] DJE-E-3; MDL-3-ELEC, p.46.
[477] DJE-E-3.
[478] Division 90, Direct Testimony of David J. Effron. P.14.
[479] Id., p.14.
[480] Id., p.15.
[481] Id., pgs.15-16.

the Company's control.[482] Mr. Effron felt the proposal inappropriately shifted a risk within the Company's control to ratepayers.[483]

Regarding the Storm Fund deficit, Mr. Effron proposed eliminating the Storm Cost Recovery Factor and reinstating the storm fund accrual in base rate cost of service at the rate of $1,800,000 annually and shifting the amortization of the $2.5 million per year to an annual credit of $2.5 million to the Storm Fund, commencing January 1, 2014.[484] Mr. Effron felt his proposal would serve the dual purpose of eliminating the deficit and restoring the reserve, which precluded the necessity of the Storm Cost Recovery Factor. The effect of Mr. Effron's Storm Fund proposal was an overall reduction of $1,641,000 to the Company's total rate year cost of service.[485]

Mr. Effron reduced the Company's pro forma storm damage expenses by $1,112.000.[486] Mr. Effron's storm damage expense was based on the Company's 5-year average of storm damage costs charged to O&M for the period 2007 through 2011, as opposed to the 2011 storm damage costs proposed by the Company which were much higher than prior years.[487] Mr. Effron felt the 5 year average was more representative of the normal level of annual storm damage expense the Company would likely incur in the future.[488] He reduced depreciation expense by $136,000 to be consistent with his reduction of $3,986,000 to plant in service.[489] He reduced the Company's adjustment for taxes and other income by $61,000,000 for the payroll

[482] Id., p.15.
[483] Id., p.15-16.
[484] Id., p.18.
[485] Id., pgs.18-19.
[486] Id., p.20.
[487] Id. Pgs.19-20.
[488] Id.
[489] Id., p.21, 24; DJE-E-5.

taxes associated with the 26 U.S. Foundation employees and two Consumer Advocates which Mr. Effron had removed from cost of service.[490]

2. <u>Rate Base</u>

Mr. Effron made a number of adjustments to the Company's rate year rate base. For non-ISR plant in service, Mr. Effron took the Company's actual 2012 non-ISR plant additions through the end of June, $317,000, and then prorated this to an annual rate of $634,000. Using the annual rate of $634,000, Mr. Effron calculated a pro-forma adjustment for non-ISR plant addition through the end of the rate year (January, 2014) of $1,004,000. The Company had included rate year non-ISR plant of $4,990,000.[491] Mr. Effron therefore reduced the Company's non-ISR plant in service included in rate base by $3,986,000 and adjusted the average balance of rate year accumulated depreciation associated with the non-ISR plant in service adjustment by $94,000.[492] He also adjusted the accumulated depreciation reserve by $570,000 to include the Asset Retirement Obligation ("ARO") on the Company's balance sheet in the depreciation reserve deducted from plant in service.[493]

Mr. Effron made three adjustments to the Company's balance of accumulated deferred income taxes ("ADIT") deducted from plant in service. To reflect his reduced level of non-ISR plant in service, Mr. Effron reduced the Company's ADIT by $389,000.[494] He increased the Company's ADIT by $11,935,000 to correct a mistake in the Company's calculation, and finally, he eliminated the deferred tax debit balance related to net operating losses ("NOL") from the determination of the rate base deduction for ADIT.[495] Mr. Effron's NOL adjustment resulted in

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[490] Id., p.21; DJE-E-6.
[491] MDL-3-ELEC
[492] Id., p.24.
[493] Id., pgs.24-25.
[494] Id., p.25; DJE-E-8.2.
[495] Id., pgs. 25-26; DJE-E-8.2

an increase to the Company's ADIT of $12,132,000.[496] Mr. Effron's net adjustment to ADIT was $23,678,000.[497] Mr. Effron felt it was appropriate to eliminate these net operating losses because the Company represented in a data response that the NOLs related to the tax years ended March 31, 2009 and March 31, 2010. Mr. Effron reasoned that since these NOLs must be carried back to prior years, the Company would have sufficient taxable income in the carry back period to fully utilize these net operating losses, and they should therefore not be included in the Company's calculation of ADIT.[498]

Mr. Effron noted that the Company had not deducted accrued reserve for injuries and damaged from plant in service. Accrued reserve for injuries and damages is a deduction taken from rate base which reflects any expenses the Company accrues in the test year in excess of actual cash disbursements.[499] Mr. Effron stated that the Company's test year balance of injuries and damages reserve attributable to distribution service was $4,908,000 and deducted this amount from rate base.[500]

Mr. Effron calculated the Company's return on rate base at $38,528,000, using the Division's proposed rate of return of 7.11%.[501] Mr. Effron's return on rate base was $6,632,000 less than the Company's proposed return of $45,160,000.[502]

3. <u>Mr. Effron's Adjustments to Gas Revenue Requirement</u>

Mr. Effron calculated a gas revenue requirement of $164,621,000 and gas revenue deficiency of $16,634,000.[503] Mr. Effron's gas revenue requirement and gas revenue deficiency were $8,507,000 and $13,755,000 less, respectively, than the Company's gas revenue

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[496] DJE-E-8.2.
[497] Id.
[498] Division 89, Direct Testimony of David J. Effron, p.26.
[499] Division 89, Direct Testimony of David J. Effron, p.28.
[500] Id., DJE-E-8.
[501] Division 89, Direct Testimony of David J. Effron, pgs.28-29; DJE-E-8.
[502] DJE-E-8.
[503] DJE-G-1.

requirement and deficiency.[504] Similar to his analysis of the Company's electric revenue requirement, Mr. Effron managed to reduce the Company's proposed gas increase by adjusting the Company's rate year cost of service and revenues, applying a different rate of return to rate base and factoring in other adjustments which are discussed below. Most of Mr. Effron's adjustments to the Company's gas cost of service mirrored his adjustments proposed for the Company's electric cost of service.

Mr. Effron proposed a rate year cost of service of $164,621,000 which included adjustments to variable pay, uninsured claims, LNG terminal labor, customer outreach and education, customer advocates, foundation support, uncollectible accounts expense, taxes other than income and income tax expense.

Mr. Effron decreased the Company's variable pay adjustment by $176,000 to correct the Company's erroneous inclusion of DSM (demand side management) in test year variable pay as opposed to rate year variable pay.[505] As a result of misclassified expenses related to workers compensation claims, the Company incorrectly reported test year uninsured claims of $395,202.[506] The correct number of test year uninsured claims was $618,449.[507] Mr. Effron compared this corrected amount of uninsured claims to the Company's five year average which resulted in a reduction of $223,000 to the Company's rate year uninsured claims.[508] Mr. Effron also reduced rate year operation and expense by $453,000 for gas supply costs which the Company had inadvertently expensed instead of flowing through the gas cost recovery ("GCR") mechanism.[509]

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[504] Id.
[505] Division 3, National Grid's Response to Division 2-7-GAS (05/25/12); DJE-G-4.
[506] Division 89, Direct Testimony of David J. Effron, p.30.
[507] Id.
[508] Id., pgs.30-31; DJE-G-4.
[509] Id., p.31.

Mr. Effron removed from rate year gas cost of service $156,000 which the Company had proposed to enhance customer outreach and education for the same reasons previously cited on the electric side-- the Company failed to prove this expense would lead to improved communications with customers.[510] Consistent with his electric cost of service adjustment, he also removed from rate year gas cost of service $156,000 which the Company had proposed for the two consumer advocate positions as well as the $92,000 expense for the U.S. Foundation employees scheduled for hire in October of 2012.

Applying Mr. Gay's proposed net write-off percentage, 2.891%, to uncollectible accounts, Mr. Effron proposed a rate year uncollectible accounts expense of $4,544,000.[511] The Company had proposed a rate year uncollectible accounts expense of $5,245,371 based on a proposed net write-off rate of 3.79%.[512] Mr. Effron recommended that the Commission reject the Company's proposal to implement a fully reconciling mechanism for gas commodity uncollectible accounts expense reiterating the reasons cited for the electric commodity bad debt reconciliation mechanism.

Mr. Effron adjusted the Company's payroll tax expense to coincide with his adjustments to wages and salaries noted above. As a result of his elimination of the consumer advocates and U.S. Foundation positions, as well as his variable pay adjustments, Mr. Effron further reduced the Company's rate year payroll tax expense by $32,000.[513] Mr. Effron proposed a rate year income tax expense of $8,411,000.[514] This income tax expense was calculated by applying the return method (income tax rate of 35%) to rate year income, subtracting AFUDC income of

[510] Id.
[511] Id., p.33; DJE-G-3.
[512] MDL-3-GAS, p.45.
[513] DJE-G-5.
[514] Division 89, Direct Testimony of David J. Effron, p.35; DJE-G-6.

$708,000 and adding AFUDC income of $11,000, for a net reduction in AFUDC income of $697,000.[515]

4. Forecasted Revenues

Mr. Effron disagreed with the Company's forecast of customer counts and gas deliveries in the rate year for the residential heating, C&I and HLF XL FT-1 classes. In the residential heating class, Mr. Effron found the Company's customer counts to be low in comparison to the five year growth rate for the period 2006 through 2011.[516] The Company had forecasted 202,140 residential hearing customers for the rate year, whereas Mr. Effron believed the forecasted number of residential heating customers in the rate year should be 203,728 based on the Company's actual annual growth rate of 2,270 customers for the six month period ending June 30, 2011.[517] Mr. Effron felt it was appropriate to use the six month growth rate, which was higher than the 5 year average growth rate, since the Company is forecasting an increase in conversions from oil to gas.[518] Mr. Effron's forecasted number of residential heating class customers resulted in additional rate year revenues of $697,000.[519]

Mr. Effron felt the Company had underestimated rate year customer counts in the C&I class as well. The Company forecasted a decrease of 106 medium C&I customers for the nineteen month period from June 2012 through January 2014. Mr. Effron testified that based on the first six months of 2012, which reflected an increase of 35 C&I customers, the Company could expect the C&I customer counts to remain level from the twelve months ended June 2012

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[515] Id.
[516] The growth rate for the period 2006-2011 was 1,541; however, the Company forecasted an increase of 2007 residential heating customers for the nineteen month period from June 2012 through January 2014 which is equivalent to an annual growth rate of 1,268 customers. Id, Direct Testimony of David J. Effron, p.38.
[517] Division 89, Direct Testimony of David J. Effron, p.38.
[518] Id.
[519] Id., p.39.

to the rate year.[520] Since the Company's actual C&I customer count had increased by 106 in the twelve month period ending June 30, 2012, Mr. Effron forecasted an increase of 106 in the rate year C&I customer count level.[521] Mr. Effron's forecasted customer count for the C&I class increased the Company's rate year revenues by $365,000.[522]

Mr. Effron also forecasted increases in the number of C&I FT-2 and HLF XL FT-1 customers, whereas the Company had proposed decreases in customer count and delivery levels for these two classes. For the C&I FT-2 class, Mr. Effron felt the forecasted customer count for the rate year should be 1,250, as opposed to the Company's 1,036.[523] This adjustment resulted in an increase of $842,000 to the Company's rate year base rate revenues.[524] Similarly, noting that there was no downward trend in deliveries from 2011 to 2012, Mr. Effron recommended using the Company's test year revenues as the rate year forecasted revenues.[525] Accordingly, Mr. Effron recommended increasing the Company's rate year revenues for the HLF XL FT-1 class by $1,057,000.[526] All of Mr. Effron's adjustments to revenues and deliveries resulted in a total increase in the Company's base rate year revenues of $2,960,000.[527]

5. <u>Rate Base</u>

After adjusting the Company's gas rate base for accumulated depreciation by ($2,623,000) and adjusting injuries and damages by ($190,000), Mr. Effron arrived at a rate base

[520] Id., p.40.
[521] Id.
[522] Id.
[523] Id., p.42.
[524] Id.
[525] Id., pgs.42-43. Mr. Effron compared the average number of HLF XL FT-1 customers in the first six months of 2012, 64, to the average number of customers in fiscal year 2012, which was 61. He also compared deliveries to the HLF XL FT-1 class in the first six months of 2012 to deliveries in the first six months of 2011 and found them to be roughly the same. For the Company's deliveries and customer counts for 2011 and the first six months of 2012, see National Grid's Response to DIV-16-4-GAS.
[526] Id., p.43.
[527] DJE-G-8.

for gas operations of $367,512,000.[528] Mr. Effron recommended that the Company be authorized to earn a return on rate base of $27,159,000 based on Mr. Kahal's proposed rate of return of 7.39%.[529]

6. Pension Adjustment Mechanism ("PAM")

Mr. Effron did not take a position regarding the Company's proposal to implement a pension adjustment mechanism ("PAM") for its electric distribution system.[530] Since a PAM was already in place for the Company's gas distribution operations, he expressed the view that there was "little reason" to treat Narragansett Electric differently from Narragansett Gas.[531] Mr. Effron recommended that if the Commission approves the PAM for the Company's electric distribution operations, it should require that the Company fund the Narragansett Electric pension and OPEB obligation in an amount at least equal to the amount collected from customers.[532]

7. Property Tax Reconciliation Mechanism

Mr. Effron advised the Commission not to approve the property tax reconciliation mechanism, claiming that it is contrary to sound ratemaking practice and unnecessary since two-thirds of the Company's increase in tax expense, on the electric side, is due to an increase in taxable property, and only one-third of the Company's increase in tax expense was due to an increase in tax rates.[533] On the gas side, Mr. Effron noted that four-fifths of the increase in property tax expense from 2010-2011 was due to an increase in taxable property whereas only

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[528] DJE-G-7. The Company had proposed a rate base of $369,945,459 which included accumulated depreciation of ($338,627,000). The Company did not adjust its gas rate base for injuries and damages. MDL-3-GAS, p.58.
[529] DJE-G-7. The Company had proposed a return on rate base of $30,495,000 based on a rate of 8.24%. MDL-3-GAS, p.2.
[530] Division 89, Direct Testimony of David J. Effron, p.44.
[531] Id.
[532] Id.
[533] Id., pgs. 45-46.

one-fifth of the increase was due to tax rate increases.[534] He felt that the property tax reconciliation mechanism was unnecessary because the Company already recovers the major cause of changes in property tax expense outside of base rates, through the Company's Infrastructure, Safety and Reliability ("ISR") Plan.[535]

B. Direct Testimony of Matthew I. Kahal

Mr. Kahal recommended that the Commission approve a return on equity ("ROE") of 9.50% for the Company's electric and gas distribution operations.[536] He recommended an overall rate of return of 7.11% and 7.39%, respectively, for the Company's electric and gas distribution operations.[537] Mr. Kahal's recommended returns were based on the following capital structure: 51.8% long-term debt; 1.3% short-term debt; 46.7% common equity; and 0.2% preferred stock.[538] Mr. Kahal's 9.5% ROE was based on the DCF model applied to three (3) proxy groups—a group of electric utilities, a group of gas utilities and a group of vertically integrated electric utilities similar to those selected by Mr. Hevert.[539] Mr. Kahal's proxy groups were very similar to Mr. Hevert's proxy groups.[540] Mr. Kahal confirmed his DCF results by applying the Capital Asset Pricing Model ("CAPM").[541] Mr. Kahal's model results ranged from 8.4% to 9.4%.[542] In addition to these model results, Mr. Kahal took into consideration several other factors in support of his 9.5% ROE.

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[534] Id., p.46.
[535] Id.
[536] Division 89, Direct Testimony of Matthew I. Kahal, p.6.
[537] Id., p.6.
[538] Id.
[539] Id., p.8.
[540] Mr. Kahal used all of Mr. Hevert's proxy companies with the exception of two unregulated generation companies because of their higher risk. He added AGL Resources to Mr. Hevert's gas proxy group and Northeast Utilities to the electric distribution group. Mr. Kahal presented his electric distribution data both with and without C.H. Energy, a company which was involved in a merger at the time of his analysis. Id., p.34.
[541] Id.
[542] Id., p.12.

Mr. Kahal noted that contrary to Mr. Hevert's allegation, Narragansett is a low-risk utility which had not experienced an increase in either business or financial risk since the last rate case or relative to other utilities in recent years.[543] He criticized Mr. Hevert for claiming Narragansett is riskier than the proxy companies yet failing to propose an adjustment to his cost of equity to reflect this alleged risk.[544] Mr. Kahal analyzed capital cost trends from 2001 through 2011, including annualized inflation, 10-year treasury yields, 3-month treasury bill yields and Moody's Single A yields on long-term utility bonds, which revealed a declining trend in capital costs.[545] Mr. Kahal noted that very low interest rates would likely continue as a result of prevailing federal policy, especially quantitative easing, and other factors such as the weak U.S. economy and European debt crisis.[546] Based on this trend, Mr. Kahal disagreed with Mr. Hevert's risk premium and CAPM results which contained assumptions that interest rates would rise over time.[547] Mr. Kahal noted that the same forces that drive down interest rates (quantitative easing, weak U.S. and European economies) would have the same effect on utility cost of equity.[548] He also felt that despite unoptimistic economic forecasts, there was no clear evidence that the recent European and U.S. equity market volatility had adversely affected the utility cost of capital.[549]

Mr. Kahal criticized several aspects of Mr. Hevert's analysis supporting his proposed return on equity. He claimed that Mr. Hevert's proposed ROE of 10.75% was not supported by his model results which were all lower than his recommended 10.75%.[550] He claimed Mr. Hevert's gas cost of long-term debt (5.90%) was miscalculated and should have been 5.65%.[551]

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543 Id.,p.9.
544 Id., p.24.
545 Id., p.13.
546 Id., pgs.13-14.
547 Id., 55.
548 Id., p.14.
549 Id., p.16.
550 Id., p.10.
551 Id., pgs.7-8.

He reduced the Company's common equity balance which he claimed had been artificially inflated by the Company as a result of its removal of Other Comprehensive Income.[552] He criticized Mr. Hevert's use of a proxy group which consisted mostly of vertically integrated electric utilities which are not representative of either Narragansett Electric or Narragansett Gas.[553] Finally, Mr. Kahal felt that Mr. Hevert's Risk Premium, CAPM and DCF calculations overstated long-term economic growth rate based on current market conditions and prevailing forecasts.[554]

Mr. Kahal found fault with Mr. Hevert's reasons for recommending an ROE that was higher than his model results. He characterized Mr. Hevert's small size argument as "absurd and unsupported."[555] Mr. Kahal felt that Mr. Hevert's own DCF results did not support his small size argument since the smaller gas proxy companies had slightly lower ROEs.[556] He also felt it was absurd to refer to Narragansett as a small company when it is a wholly owned subsidiary of National Grid USA with assets totaling $39 billion.[557] He called Mr. Hevert's reference to the Decoupling Act in support of the small size argument "irrelevant," claiming there is nothing in the Decoupling Act which supports an upward adjustment to cost of equity based on the size of the Company.[558]

Mr. Kahal used an equity risk premium ranging from 5% to 8% resulting in a cost of equity ("COE") range of 6.5% to 8.6% and a midpoint of 7.6%.[559] Mr. Hevert used a COE range of 8.5% to 10.0% which Mr. Kahal said was unrealistic, out of line with expert opinion and too

[552] Id., pgs.6-7.
[553] Id., p.11.
[554] Id.
[555] Id., p.26.
[556] Id.
[557] Id.
[558] Id., p.27.
[559] Id., pgs.44-45. Mr. Kahal cited *Principles of Corporate Finance* by Brealey, Myers and Allen to support his equity risk premium range of 5% to 8%. Id., p.47.

high.[560] Mr. Kahal advised the Commission not to rely on Mr. Hevert's risk premium model because it relied on the relationship between interest rates and ROEs allowed by regulatory decisions which cannot be assumed to be the same thing as the market cost of equity.[561] For this reason, Mr. Kahal said that while Mr. Hevert's risk premium method may be helpful in describing the behavior of utility regulators, it is not a true cost of equity method.[562] He took issue with Mr. Hevert's assumption, once again, that long term interest rates will increase over time and said this was contrary to the trend of falling interest rates.[563] Mr. Kahal said it is inappropriate to assume that the cost of equity will be higher in future years.[564] He said it was "poor ratemaking" and "inconsistent with market evidence.[565] According to Mr. Kahal, this skewed all of the Company's forecasts.[566]

C. Direct Testimony of Bruce R. Oliver

On behalf of the Division, Bruce Oliver addressed the Company's gas sales and revenue forecasting, its allocated cost of service study ("ACOSS"), proposed rate structure and tariff changes.[567] He reviewed the testimony of Paul Normand, Ann Leary, Leo Silvestrini and to some extent, Evelyn Kaye.

1. Gas Sales and Revenue Forecasts

Mr. Oliver criticized the Company's forecasting methodologies claiming that 1) they didn't explain large percentages of variation observable in the historic data; 2) they include variables which the estimated coefficient cannot be reliably differentiated from zero at the 95% confidence level; and, 3) the Company's explanation of the weather normalization process is

[560] Id., p.46.
[561] Id., pgs. 53-54.
[562] Id., p.54.
[563] Id., p.55.
[564] Id.
[565] Id.
[566] Id.
[567] Bruce R. Oliver is President of Revilo Hill Associates, Inc., 7103 Laketree Drive, Fairfax Station, VA 22039.

flawed.[568] Mr. Oliver explained the Company's use of inappropriate R-Square values in its forecasting models. An R-Square value represents the level of variability that is accounted for by a statistical model.[569] An R-Square value of 1.0 means the model explains all of the variability in the input data.[570] An R-Square value of 0.5 means the model explains only 50% of the variation in the input data used.[571] Mr. Oliver noted that the Company reported R-Square values of less than 0.5 in twelve of its forecasting models, and six of the Company's models used to project the number of customers and customer use had R-Square values of less than 0.3.[572] Mr. Oliver interpreted the Company's R-Square values to mean that 70% of the variation in the data used in the models could not be explained by the models.[573] According to Mr. Oliver, this indicated a serious flaw in the Company's models which skewed all of its use-per-customer forecasts.[574]

2. ACOSS

Mr. Oliver criticized the ACOSS presented by Paul Normand on behalf of the Company on several grounds. He said that since Mr. Normand's study was based on a future test period, the twelve months ending January 31, 2014, it was less certain and less reliable since there is a greater potential for error with future as opposed to historical test periods.[575] Mr. Oliver advised the Commission not to place undue reliance on the precision of the Company's ACOSS not only because of its basis on a future test period but for other reasons as well.[576] Specifically, Mr. Oliver had four criticisms of the Company's ACOSS. He claimed that it did not allocate costs to non-firm customers. It did not allocate costs to gas marketers or provide a basis for charges

[568] Division 89, Direct Testimony of Bruce R. Oliver, p.6.
[569] Id., p.7.
[570] Id.
[571] Id.
[572] Id.
[573] Id.
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[575] Id., pgs.12-13.
[576] Id., p.14.

billed to gas marketers. It did not property allocate income taxes among rate classes, and it did not properly allocate production related expense consistent with the DAC and GCR.[577]

Mr. Oliver pointed out that the Company's ACOSS called for billing non-firm customers on a value-of-service basis which is a change from the current practice of billing non-firm transportation customers on a fixed, discounted rate, yet it did not explain the reason for this change or for the proposed non-firm, duel fuel margin threshold of $1,512,209.[578] He further stated that the Company's failure to allocate costs to non-firm transportation service customers meant that those costs would be unfairly allocated to firm service rate classes which Mr. Oliver felt was unfair.[579] Mr. Oliver noted that the Company had not allocated costs to gas marketers in many years and expressed the importance of doing this to ensure that residential customers do not bear the costs of services that provide no benefit to them.[580] Mr. Oliver stated that income taxes should be allocated to rate classes in proportion to each class' allocated rate base costs.[581] Referring to the residential non-heating class, he criticized the Company's use of a standard tax computation methodology to a class that has negative income, negative taxable income and a negative contribution to the Company's return requirements.[582] He felt the Company was rewarding a class that fails to contribute anything positive to the Company's required earnings while it penalized classes producing above system average rates of return with increased income tax responsibilities.[583] Finally, Mr. Oliver noted that the Company's ACOSS was not consistent with the DAC and GCR because it did not consider total design winter throughput in the design winter allocator. The design winter allocator used by the Company only uses degree day

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577 Id., p.15.
578 Id., p.17.
579 Id., p.16.
580 Id., p.22.
581 Id., p.23.
582 Id., pgs. 22-23
583 Id.

sensitive throughput volumes by class under design winter conditions.[584] Load volumes were not considered in the development of this allocator. This is inconsistent with the DAC and GCR which allocate expenses on the basis of total design winter throughput measures.[585] Mr. Oliver recommended that the design winter allocator be amended to include total design winter throughput including both heat load and base load.[586]

3. Proposed Rate Structure and Tariff Changes.

Bruce Oliver's analysis of the Company's rate structure and tariff changes covered five subjects: a) distribution of proposed revenue increases; b) changes in firm service rates; c) non-firm service rate issues; d) the Company's bill impact analysis; and, e) other rate and tariff changes.

a. Distribution of Proposed Revenue Increases

Bruce Oliver felt that the proposed rate increase for the Extra Large C&I LLF (Low Load Factor) was too high. The rate increase for this class was twice the system average rate of return and approx. 600 basis points above the post-increase rate of return for any other class.[587] Mr. Oliver recommended lowering the rate increase for the Extra Large C&I LLF to 6.635%.[588] To compensate for the lowering of the Extra Large C&I LLF increase, Mr. Oliver recommended slightly increasing the revenue requirements of the other non-residential classes.[589] To address the negative rate of return of the Residential Non-Heating Class, Mr. Oliver recommended either a mechanism whereby the revenue requirement of the Residential Non-Heating class would be

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[584] Id., p.27.
[585] Id.
[586] Id.
[587] Id., p.30.
[588] Id.
[589] Id., p.31.

gradually ratcheted up on an annual basis with offsetting revenue reductions to other classes through the DAC or a one-time increase of 1.5 times the system average.[590]

b. Changes in Firm Service Rates

Mr. Oliver compared the Residential and Commercial customer charges proposed by the Company with the median levels of other gas utilities in New England and found that the Company's customer charges were higher.[591] He also noted that other New England gas utilities have the same customer charges for both Residential Heating and Non-Heating customers whereas National Grid's has a $2 higher customer charge for Residential Heating customers.[592] To address this disparity, Mr. Oliver recommended that the Residential Heating customer charge be set at $14.00, and if the Commission does not approve the full increase requested by the Company, then it should be lower than $14.00 but not lower than the Residential Non-Heating customer charge of $12.50.[593]

Mr. Oliver provided a proof of revenue analysis which revealed, according to his calculations, that the revenue increases for the Medium, Large and Extra Large C&I customer classes were higher than reported by Company witness, Paul Normand. Paul Normand indicated these classes would be subject to an overall increase of 9.32%; however, Mr. Oliver's calculations revealed an increase of 20.83% for the Medium C&I class.[594] He also found discrepancies in the rate increases reported by Mr. Normand for all of the other Medium, Large and Extra Large C&I rate classes.[595] Mr. Oliver attributed these discrepancies to the Company's inclusion of anticipated revenue from upcoming RDM and ISR filings which Mr. Oliver said was

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[590] Id., pgs.31-32.
[591] Id., p.33.
[592] Id.
[593] Id., p.34. The customer charge is a fixed monthly charge on a customer's bill.
[594] Id., pgs.36-37.
[595] Id., p.37.

inappropriate. Mr. Oliver argued that projected revenue from future RDM and ISR filings should not be considered in the determination of base rate charges for gas service.[596]

c. Non-Firm Service Rates Issues

Mr. Oliver pointed out that although it was not mentioned in the Company's direct testimony, the Non-Firm rate classes would be subject to dramatic and unacceptably large increases.[597] Mr. Oliver further noted that charges for the Non-Firm service classes were incorrectly calculated.[598] Specifically, the Company had incorrectly included Firm service revenue in its calculation of Non-Firm service rates.[599] Mr. Oliver said this was contrary to the Commission's order in Docket. 3943 which requires that Non-Firm service charges are to be computed as a 20% discount from Firm service rates.[600] He further stated that the Firm service rates were also miscalculated because they included adjustments for ISR and RDM.[601] Mr. Oliver said these miscalculations resulted in increases to Non-Firm service ranging from 26.2% to 84.7%, allowing the Company to double recover costs from Non-Firm customers.[602] To rectify this flaw, since a fully developed set of cost allocations for the Non-Firm class is not available, Mr. Oliver recommended maintaining the 20% discount from Firm rates until the next base rate case.[603] Mr. Oliver further recommended that the Company be ordered to file an ACOSS in the next base rate case which includes explicit allocations of costs to Non-Firm service customers to assist the Commission in setting appropriate revenue requirements and

596 Id., pgs.37-38.
597 Id., p.38.
598 Id., p.39.
599 Id., pgs.39-40.
600 Id., p.39.
601 Id.
602 Id., pgs.39-40.
603 Id., p.40.

charges for this rate class.[604] In the alternative, Mr. Oliver offered his own calculations for a Non-Firm Service Distribution charge.[605]

d. Bill Impact Analysis

Mr. Oliver characterized the Company's bill impact analysis as out of date because it was based on the same average use per customer used in Docket 3943 and because it inappropriately includes an RDM factor.[606] Mr. Oliver stated that the RDM is a retrospective adjustment mechanism and, as such, does not allow the Company to bill for anticipated future revenue variances.[607]

e. Other Rate and Tariff Changes

Mr. Oliver objected to i) the Company's proposed changes to the GCR mechanism ii) the proposed changes to the DAC mechanism, iii) the proposed paperless billing credit, iv) RDM related interclass revenue shifts and v) the Company's inclusion of projected RDM adjustments in base rate revenues.

i.) GCR. Mr. Oliver argued that the Company's commodity bad debt tracker would add to the volatility in annual GCR charges which is inconsistent with the Commission's policy to promote stability in gas costs billed to Rhode Island customers.[608]

ii.) DAC. Mr. Oliver advised the Commission not to approve the Company's proposed Dual Fuel customer tracking mechanism because he felt the Commission should wait to see

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[604] Id., p.41.
[605] Id., p.41. There are five Non-Firm rate classes: Medium C&I, Large C&I LLF, Large C&I LHF, XL C&I LLF and XL C&I LHF. Mr. Oliver offered three alternative sets of distribution charge calculations for these rate classes. He offered one calculation which removed customer charge revenue; one which removed RDM and ISR adjustments, as well as customer charge revenue; and one which was based on the Division's recommended overall revenue requirement and Firm rate designs. None of these rates were included in the Amended Settlement approved by the Commission. Id., BRO-12.
[606] Id, p.43.
[607] Id., p.44.
[608] Id., p.47.

the merits of the new mechanism that was just approved especially when the current rate increase may lead to more migration between the Firm and Non-Firm rate classes.[609] Mr. Oliver felt it was not clear whether the Company's proposal would simplify Dual Fuel customer tracking and recommended that the Company try to find ways to limit customer migration.[610] Mr. Oliver objected to the Company's proposal to change the current threshold for determining Duel Fuel on-system margin credits to $1,512,209 applicable to only Non-Firm service customers.[611] Mr. Oliver felt this threshold was too low and recommended that it be increased to $1.8 million if applicable to Non-Firm duel fuel customers.[612] This recommendation was qualified, however, by his preference to maintain the current method for determining on-system margin credits, namely that it continue to be based on revenue margins for both Firm and Non-Firm Duel Fuel customers.[613] He further qualified his recommendation by stating that if the current Duel Fuel margin is maintained, applicable to both Firm and Non-Firm service margins, then the $2.8 million threshold should be raised to $3.8 million, based on actual margin revenue from Firm and Non-Firm Duel Fuel customers over the past three years.[614]

iii) <u>Paperless Billing Credits.</u> Mr. Oliver did not object with the Company's proposal to offer paperless billing credits, but he recommended that the Company be required to provide annual or semi-annual reports, in the first couple of years of implementation, documenting customer participation and cost savings.[615] Mr. Oliver also recommended that the paperless

[609] Id., pgs.48-53.
[610] Id., p.48.
[611] As of the date of the Company's filing, on-system margin credits were applicable to both Firm and Non-Firm service customers.
[612] Id., p.51.
[613] Id.
[614] Id., pgs.53-54.
[615] Id., pgs.58-59.

billing credits not be considered revenue variances for purposes of revenue decoupling since the billing credits are offset by cost reductions.[616]

iv.) <u>RDM Related Cross-Subsidization.</u> Mr. Oliver addressed the issue of cross-subsidization among rate classes due to the implementation of the RDM which he originally raised in Docket 4206. He applied the RDM factor projected by Company witness, Ann Leary, ($0.0153/therm) to the Rate Year throughput estimates by rate class and compared those revenues to the computed revenue variance by rate class and discovered that more than $2.4 million of revenue requirements would be shifted from the Residential Heating class to the Residential Non-Heating, Small C&I and Medium C&I rate classes.[617] To rectify this cross-subsidization, Mr. Oliver recommended that the Commission revise the RDM to require the Company to reconcile revenue recovery separately for each rate class and calculate all RDM factors on a class by class basis.[618] Mr. Oliver rejected the Company's projected RDM adjustment of $3,888,810 saying that it was inappropriate to include adjustments for a projected rate year unless they are known.[619] He stated that if the revenue-per-customer targets are reset in this case, then the expected RDM adjustment should be zero, and only after the fact RDM adjustments are appropriate.[620] Finally, he recommended that the Commission open a separate docket to review and address RDM related cross-subsidizations.[621]

v.) <u>Inclusion of RDM Adjustments in Base Rate Revenues.</u> Mr. Oliver cautioned the Commission to consider the impacts of the newly approved RDM on base rate determinations. He reiterated that ISR and RDM revenue should not be included in revenue per customer

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[616] Id., p.59.
[617] Id., pgs. 56-57; BRO-11. Mr. Oliver found similar cross subsidization among these rate classes when performing the same comparisons using the RDM adjustment from the Company's recent 2012 DAC filing. BRO-11.
[618] Id., p.58.
[619] Id., p.55.
[620] Id., p.62.
[621] Id.

calculations since this revenue is not part of base rates.[622] Mr. Oliver clarified that he felt it was appropriate to include this revenue in existing rates for comparison purposes based on an historic test year.[623]

D. <u>Direct Testimony of Lee Smith</u>

Mr. Lee Smith addressed the allocation of service company costs to Narragansett Electric and Narragansett Gas.[624] The Company claimed total expenses of $127 million for Narragansett Electric, $42 million of which were direct and allocated service company charges.[625] Allocated charges for Narragansett Electric were $20.5 million.[626] The Company reduced its electric revenue requirement by $2.6 million for anticipated productivity and efficiency savings from the restructuring program.[627] For Narragansett Gas, the Company claimed total expense of $92.5 million. Of this amount, $49.7 million consisted of allocated service company charges.[628] The gas revenue requirement was reduced by $1.1 million for projected productivity and efficiency savings from restructuring.[629]

Mr. Lee agreed in general with the Company's methodology for reallocating service company costs resulting from the merger of the KeySpan and National Grid financial accounting systems. He agreed with the three-point allocator adopted by the Company, saying that it would more reasonably reflect the need for general costs such as corporate oversight, financial and accounting costs.[630] He did, however, identify some flaws in the Company's reallocation of service company costs. He noted the large amount of Narragansett Gas and Narragansett Electric

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[622] Id., p.55.
[623] Id.
[624] Lee Smith is a managing consultant and senior economist at La Capra Associates. Division 92, p.2.
[625] Id., p.4.
[626] Id.
[627] Id.
[628] Id.
[629] Id.
[630] Id., p.9.

costs resulting from the reallocation of service company costs and the fact that many of those costs originated from affiliates in other jurisdictions, in particular the southern New York/Long Island area. He felt that that system wide operations and management decisions made based on a review of out of state affiliates may not always be justified.[631] He also noted that the consulting firms hired by National Grid (Ernst & Young and PA) simply confirmed that the affiliate services were valid and appropriate.[632] They did not verify the efficiency of the costs associated with these services, whether they were lower than the cost of services purchased from outside vendors or whether they were otherwise mitigated.[633] He found it noteworthy that RFPs were not issued for purposes of determining the competitiveness and/or reasonableness of service company costs.[634] Mr. Smith disagreed with the Company's allegation that affiliate services could not be outsourced due to the nature of their services and the knowledge required to perform them, arguing that many services such as billing and engineering could be performed by third party vendors.[635] He also disagreed with the Company's defense that its affiliate services did not include a markup, noting that embedded in service company costs are many other costs such as overhead, pensions, benefits, working capital, depreciation and a return to the service company, which are akin to a markup.[636] Mr. Smith further felt that many reasons, such as area labor or real estate costs, could be attributed to service company costs that are higher than market.[637]

E. Direct Testimony of Dr. Emma L. Nicholson

[631] Id., p.10.
[632] Id.
[633] Id.
[634] Id.
[635] Id., p.11.
[636] Id.
[637] Id., pgs.11-12.

Dr. Emma L. Nicholson's testimony concerned the allocated class cost of service study ("ACOSS") for electric distribution operations proposed by Howard S. Gorman.[638] Dr. Nicholson agreed that the Company's classification and allocation of distribution plant was consistent with the Commission's Order in Docket No. 4065.[639] She agreed that the Company's proposed revenue spread was reasonable and acceptable, and she agreed with the Company's proposed methodology for calculating the reconciliation components of the Transmission Service Cost Adjustment Provision and the Energy Efficiency Program Provision.[640] She recommended, however, that the allocation of Customer Service and Information Expenses be allocated based on energy use at the meter.[641] She also recommended that the Commission reject the Company's proposal to increase the customer charges for the Residential Low Income (A-60) and Propulsion (X-01) classes.[642] Dr. Nicholson felt there was no basis for increasing the customer charge on the low income class since this rate is already subsidized, not based on cost of service and would negatively impact the poorest customers.[643] She also felt that the Company's proposed 27% increase in the Propulsion class' customer charge was excessive.[644]

F. <u>Direct Testimony of Bruce A. Gay</u>

Bruce A. Gay reviewed the Company's proposal to recover its uncollectible accounts expense, as well as the Company's collection policies and practices.[645] Mr. Gay disagreed with Ms. Kaye's allegation that increased gas adjustment rates caused an increase in the Company's

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[638] Emma L. Nicholson holds a M.A. and Ph.D. in Economics from Georgetown University. She is employed as an Economist at Exeter Associates, Inc. Division 93, Direct Testimony of Emma L. Nicholson, p.1.
[639] Id., pgs.2,14,36.
[640] Id., pgs.33-35,36.
[641] Id., pgs. 2,20,36.
[642] Id., pgs. 2,29,31,36.
[643] Id., p.29.
[644] Id., p.31.
[645] Bruce A. Gay is a utility consultant and founder of Monticello Consulting. Division 94, Direct Testimony of Bruce A. Gay, p.1.

gas charge-offs.[646] Mr. Gay felt that the trends in average annual bills for Residential and Non-Residential customers and the Company's gross charge-offs for the period 2007 through 2011, revealed no causal relationship between gas adjustment rates and increase in charge-offs.[647] He also disagreed that increases in electric supply prices prior to 2009 caused an increase in the Company's uncollectible accounts expense.[648] On the contrary, he found that electric supply costs decreased during the period 2006 through 2011 while the Company's gross charge-offs increased during this same time period.[649]

Mr. Gay felt that the most important factor impacting the Company's uncollectible accounts expense was the Company's own management of its accounts and collection practices which he felt could have been more efficient. He reviewed electric and gas charge-offs for both Residential and Non-Residential accounts for the periods 2008 through 2011 and 2007 through 2011 and found, with the exception of gas Non-Residential accounts, that the Company allowed balances to reach unnecessarily high levels.[650] Mr. Gay felt that the Company had failed to mitigate charge-offs by allowing arrearage balances to linger and grow beyond a level the customer could manage.[651] He also criticized the Company for not implementing the PMP scoring system until January 2012.[652] Based on these observations, Mr. Gay recommended charge-off percentage rates of 0.92% for the Company's electric operations and 2.81% for gas operations.[653]

IV. Direct Testimony of the U.S. Navy

A. Direct Testimony of Ali Al-Jabir

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[646] Id., p.4.
[647] Id., p.5.
[648] Id., p.6.
[649] Id.
[650] Id., pgs. 8-10.
[651] Id.
[652] Id., p.11.
[653] Id., p.13.

On behalf of the U.S. Navy, Ali Al-Jabir made the following recommendations regarding the Company's rate design and ACOSS.[654] Mr. Al-Jabir asked the Commission to reject the Company's proposal to allocate meter data services expenses, retail marketing costs and customer installation expenses on the basis of energy consumption, claiming these costs were more appropriately allocated based on customer counts, as opposed to energy consumption.[655] Mr. Al-Jabir advised that Demonstration and Selling expenses in Account 912, which the Company allocated exclusively to C&I customers, should instead be allocated to all customer classes based on customer counts.[656]

Mr. Al-Jabir disagreed with the Company's proposal to cap the revenue increase for the 3,000 kW B/G-62 and X-01 Propulsion rate classes at twice the system average, claiming this would have an adverse impact on the local economy.[657] Noting the importance of large industrial customers to the local economy, Mr. Al-Jabir expressed concern that the Company's proposed increase of 26.3% on the state's largest customers was excessive and might cause a chilling effect on local investment and/or expansion.[658] To mitigate this effect, Mr. Al-Jabir recommended that a rate increase cap of 150% of the system average be imposed on customers with demands greater than 8 MW and that the rate increase for customers in the 3,000 kW B/G-62, Lighting and Propulsion rate classes be limited to twice the system average.[659]

Mr. Al-Jabir opposed the implementation of the proposed adjustment mechanisms (pension, property tax, commodity-related uncollectible expenses), claiming they would

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[654654] Ali Al-Jabir is a public utility consultant with Brubaker & Associates, a Texas consulting firm. Navy 6, Direct Testimony of Ali Al-Jabir, Appendix A, p.1.
[655] Navy 6, p.2, 9-10, 12-14.
[656] Id, p.2,14.
[657] Id., p. 2, 10-11, 17-18.
[658] Id., p.17.
[659] Id., p.2,18.

inappropriately transfer business risks assigned to the Company's investors to its customers.[660] Mr. Al-Jabir said this transfer of risk was contrary to fundamental ratemaking principles, provides a disincentive for the Company to control its costs and could ultimately lead to the Company earning more than its authorized rate of return.[661] He also felt that there was insufficient need for the trackers in light of the Company's use of a forecasted rate year in this proceeding and the existence of revenue decoupling mechanism, both of which arguably contribute to the Company's ability to control rate year costs.[662] In the event the trackers are approved by the Commission, Mr. Al-Jabir advised that the costs be allocated according to the Company's allocated cost of service study, instead of through a uniform per kWh charge.[663]

Finally, Mr. Al-Jabir proposed that the transmission, pension, property tax and storm cost adjustment mechanisms be designed on a per kW basis for customers with demand metering since the costs associated with these trackers are not linked to energy consumption.[664]

V. Amended Settlement Agreement (November 14, 2012)

On November 14, 2012, the Company filed an Amended Settlement Agreement ("Amended Settlement") which resolved all of the contested issues among the signatories and addressed storm costs associated with Hurricane Sandy.[665] In comparison to the Company's original proposal filed April 27, 2012, the Amended Settlement contained significant reductions in base rates, ROE, revenue requirements, revenue deficiencies and bill impacts. The Parties agreed to an electric distribution revenue requirement of $260,531,133 which was roughly $9.9

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[660] Id., p.3, 19-20.
[661] Id., p.20.
[662] Id., p.21.
[663] Id., p.3, 23-26.
[664] Id., p. 3, 26.
[665] This Amended Settlement Agreement was a modification of a settlement agreement filed by National Grid on October 19, 2012. The signatories of the original settlement agreement and Amended Settlement Agreement are National Grid, the Division of Public Utilities and Carriers and the U.S. Navy. This Order reviews the terms of the Amended Settlement Agreement only since it was intended to replace the original settlement agreement.

million lower than the Company's originally requested revenue requirement of $270,471,182. The settled upon revenue requirements were based on the Company's actual capital structure as of June 30, 2012 and authorized a base distribution rate increase of approximately $21.5 million for the Company's electric operations.[666] The reduced revenue requirement and revenue deficiency were due in part to the agreed upon lower return on equity of 9.5% and other concessions which reduced the Company's rate year cost of service for both electric and gas. For the electric revenue requirement, the Parties agreed to a lower uncollectible expense due to a lower write-off rate (1.25% versus 1.35%); lower weighted average cost of capital (7.28% versus 7.85%); and modifications to storm cost recovery and other cost recovery mechanisms discussed below. For the Company's gas operations, the Parties agreed to a distribution revenue requirement of $167,159,844 which is a $5.9 million reduction from the $173,128,689 revenue requirement requested by the Company in its original filing. This would result in a base distribution rate increase of approximately $11.3 million for the Company's gas operations.[667] The agreed upon gas distribution revenue requirement and revenue deficiency were based on a 9.5% return on equity, as opposed to the 10.75% return originally requested by the Company. Additional modifications to the original proposal also contributed to the reduction in the Company's rate year revenue requirements. Bill impacts associated with the Settlement were $2.56 per month for an average electric residential customer and approximately $55.00 per year

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[666] The Company's capital structure as of June 30, 2012, excluding goodwill and accumulated other comprehensive income, consisted of 0.76% short-term debt; 49.95% long-term debt; 0.15% preferred equity and 49.14% common equity. This capital structure reflects the anticipated $200 million long-term debt issuance approved by the Division on October 31, 2012 in Division Dkt. No. D-12-12 (4.88% interest rate and .75% debt expense). The debt issuance is to occur before May 31, 2013. If the impact of actual debt rates and issuance costs on cost of service exceeds $100,000 (electric) or $50,000 (gas), the Company will make a filing to adjust base rates within 60 days of the debt issuance. Settlement, pgs. 7-8, 16; MDL-3-ELEC-S, p. 61; Letter of Tom Teehan, p.2 (11/14/12); Division Order No. 20853 (Dkt. D-12-12).

[667] MDL-3-GAS-S, pgs.1-2; Letter of Tom Teehan, p.2 (11/14/12).

for an average gas residential heating customer.[668] These impacts were considerably lower than the bill impacts originally proposed by the Company ($3.97/mo. (electric) and $98.00/yr. (gas)).

As part of the Settlement, the Company agreed to waive its proposals to implement a property tax recovery mechanism and a commodity related bad debt recovery mechanism. In lieu of the these proposals, the Parties agreed to allow the Company to recover and annually reconcile these expenses, but on modified terms which reduced the Company's cost of service and ultimately its revenue requirements. The originally proposed property tax and bad debt trackers would have fully reconciled the amount of property tax and commodity related uncollectible expenses recovered in base rates to actual property tax and commodity related uncollectible expenses through separate rate adjustments.[669] The property tax tracker originally proposed would have fully insulated the Company from fluctuations in both property tax rates and investments, without including depreciation expense on base rate embedded property in the calculation of the property tax expense.[670] According to the Amended Settlement, the Company would be allowed to recover through the ISR mechanism property tax expenses resulting from fluctuations in property tax rates and plant investments; however, the Company would be required to include in its property tax expense calculation an offset for base rate depreciation expense on embedded property.[671] Inclusion of depreciation expense in the property tax calculation reduced the amount of property tax expense eligible for recovery, and the signatories agreed this provided a better representation of the Company's property tax expense. The

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[668] Based on average annual consumption of 846 therms. Settlement, Teehan Letter, p.2; PMN-8-5, p.1.
[669] Direct Testimony of Michael Laflamme, p. 116, line 1 through p.120, line 21; Direct Testimony of Evelyn Kaye, p.20, line 20 through p.22, line 14.
[670] National Grid's Response to COMM 8-8.
[671] Id.

Amended Settlement did not allow recovery of property tax expense related to non-ISR and gas growth investments through the ISR mechanism.[672]

The Amended Settlement allowed the Company to recover, and annually reconcile, its commodity related uncollectible expense using the actual, five year average write-off rates of 1.25% (electric) and 3.18% (gas).[673] This differed from the Company's original proposal for a fully reconciling recovery mechanism based on 1.35% (electric) and 3.79% (gas) write-off rates.[674] The Division did not formally oppose the Company's request to implement a pension adjustment mechanism ("PAM") for the Company's electric operations but recommended that the Company be required to fund the pension and OPEB obligation in an amount equal to the amount collected from customers.[675] The Amended Settlement authorized implementation of the PAM for Narragansett Electric on the terms requested by the Division. Namely, it contained a requirement that the Company contribute to the pension and OPEB plans the minimum funding obligation level which is the amount of pension and OPEB costs collected from customers through base rates and the PAM, plus capitalized amounts of pension/OPEB cost.[676] According to the Amended Settlement, the PAM for Narragansett Electric would operate in the same manner as the PAM approved for Narragansett Gas in Docket 3943. It would allow the Company to include an amount of pension/OPEB costs in base rates and annually reconcile any differences in this embedded amount to actual costs through a per kWh charge. The agreed upon

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[672] The Settlement includes gas growth capital investments in the RDM calculation of class revenue per customer. Settlement, p.11-12, 22; National Grid's Response to COMM 8-9.
[673] Settlement, p. 10, 20. Settlement page numbers refer to the number located at the bottom, center of the page.
[674] Settlement, p. 5, 15. Currently, the Company calculates the write-off rate each year by dividing actual net write-offs by total billed revenues. It does not use an average write off rate. Direct Testimony of Evelyn Kaye, p. 39, lines 7-9.
[675] Direct Testimony of David Effron, p.44-45.
[676] Settlement, p. 10-11. The PAM will include a carrying charge equal to the weighted average cost of capital which shall be applied to any cumulative shortfall between the minimum funding obligation and amounts contributed by the Company to the pension/OPEB plans, including payments to the service companies for allocated pension/OPEB costs. Id., p. 11. The minimum funding obligation will apply to gas pension/OPEB plans as well. Id., p. 20-21.

rate year embedded amount of pension/OPEB costs was $13,776,267.[677] In the first year, this embedded amount would be reconciled to actual costs incurred in the two months ended March 31, 2013. The pension adjustment factor ("PAF") would be filed on August 1 for effect on October 1 through September 30. In subsequent years, the PAF would be filed annually on August 1 for effect on October 1 through September 30 and would recover/credit over- or under-recoveries incurred in the prior 12 month period ending March 31.[678]

The Amended Settlement contained provisions addressing the Storm Fund to the satisfaction of the Parties, adopting the proposals requested by the Division and incorporating provisions to address significant damage from Hurricane Sandy. The Company accepted the Division's recommendation to reinstate Storm Fund accrual in base rate cost of service at the rate of $1,800,000 annually ($150,000 per month) and eliminate the Storm Cost Recovery Factor ("SCRF").[679] Additionally, the Parties agreed to credit the Storm Fund in the amount of $2,500,000 per year after fully amortizing the 2003 voluntary early retirement offer ("VERO") expense approved in Docket 3617.[680] Finally, to address fallout from Hurricane Sandy, the Parties agreed to contribute an additional $3,000,000 to the Storm Fund annually for a period of six years commencing on February 1, 2013.[681] According to the Amended Settlement, total annual contributions to the Storm Fund would be $7,300,000.[682]

The Parties accepted the rate design proposed by the Company with modifications. For electric distribution operations, the Parties agreed not to increase the customer charge for the A-

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677 MDL-3-ELEC, p.7 and MDL-3-ELEC-S, p. 7.
678 Direct Testimony of Michael Laflamme, pgs.78-79. The reason for the two month reconciliation period in the first year is because the PAM is not effective until February 1, 2013.
679 Eliminating the SCRF reduced the Company's cost of service by $1,641,000. Direct Testimony of David Effron, pgs. 18-19.
680 The VERO was scheduled to conclude on December 31, 2013. Beginning on January 1, 2014, the Company will contribute $2,500,000 to the storm fund annually ($208,333 per month.) Settlement, p. 7.
681 Settlement, p. 6.
682 This amount includes a credit to the Storm Fund of the Company's legal and other costs associated with Docket D-11-94 (Storm Irene Investigation) Id., p.7.

60 and X-01 rate classes, and they agreed to increase the rate for the G-62 class by 1.5 times the system average increase for the G-62 class as a whole. For gas distribution operations, the Parties agreed to increase the customer charge for the Residential Heating class to $13.00. They agreed to reduce the rate increase for the C& I Extra Large Load to 3.79% and to increase the Residential Non-Heating class above the overall average for all gas customer classes.[683] Rates for Non-Firm Transportation Service were recomputed to exclude Firm Service customer charges and to place a 19% cap on increases for Non-Firm customers whose rates reflect a 20% discount from the otherwise applicable Firm Service rates for Extra Large HLF and Extra Large LLF customers.[684] The Parties stipulated that the Company would file an allocated cost of service study ("ACOSS") in the next base rate case which includes a full allocation of costs to Non-Firm customers.[685] The Parties agreed to increase the Dual Fuel margin to $1.8 million annually applicable to Non-Firm Sales and Transportation Service customers.[686] To address migration of Dual Fuel customers between Firm and Non-Firm service options, the Parties agreed to adjust the margin by the customer's prior year historical usage multiplied by the migrating customer's rate.[687] The Amended Settlement Agreement provided that revenue decoupling adjustments would continue to be collected on a uniform dollars per therm basis for all classes subject to RDM adjustments.[688] The Parties stipulated that the Company would update the average use per customer amounts reflected in its bill comparisons for a typical customer in each rate class. Finally, the Parties agreed to an earnings sharing mechanism whereby accumulated earnings over the authorized ROE of 9.5%, up to and including 100 basis points, would be shared 50/50 with

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[683] National Grid 5, p.17.
[684] Id., pgs. 18-19.
[685] Id., p.19.
[686] Id., p.18.
[687] Id.
[688] Transcript (11/15/12), pgs.56-57.

customers. Earnings which are over 100 basis points above the ROE of 9.5% would be shared 75/25 in favor of customers.[689]

VI. Compliance Filing (January 24, 2013)

On January 24, 2013, the Company submitted a Compliance Filing to the Commission which updated the attachments to the Amended Settlement Agreement. The attachments were updated to reflect the Company's December 10, 2012 long-term debt issuance of $250 million, the approved rates for the recovery of uncollectible expense and the inclusion in rate base of capital additions that are currently recovered through the electric and gas ISR plans. The tariffs included in this filing were the tariffs ultimately approved by the Commission.

The Compliance Filing included the following updated revenue requirements, distribution rates and charges:

Electric Distribution Revenue Requirement…………………………………… $259,948,386[690]

Electric Distribution Revenue Increase …………………………………….. $20,925,482[691]

Residential Electric Bill Impact ……………………………………………….. $2.53[692]

Electric Delivery Rates………………………………………………………… Exhibit 1

Electric Energy Efficiency Charge………………………………………….. $0.00906/kWh

Gas Distribution Revenue Requirement…………………………………….. $166,765,895[693]

Gas Distribution Revenue Increase………………………………………….. $10,898,619[694]

Residential Gas Bill Impact…………………………………………………… $58.00[695]

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689 Id.,p.12-13, 23. Annual earnings reports filed on May 1 (electric) and July 1 (gas). The gas reporting period would change to a fiscal period (April 1 through March 31) to coincide with other financial reporting requirements.
690 Compliance Filing of National Grid (01/24/13), MDL-3-ELEC, p.3.
691 Compliance Filing of National Grid (01/24/13), MDL-3-ELEC, p.2.
692 This is the monthly bill impact for a typical residential customer consuming 500 kWh. 01/24/13 Compliance Filing, JAL-6, p.1.
693 Compliance Filing of National Grid (01/24/13), MDL-3-GAS, p.3.
694 Compliance Filing of National Grid (01/24/13), MDL-3-GAS, p.2.

Gas Distribution Rates………………………………………………………… Exhibit 2[696]

Gas Distribution Adjustment Charge……………………………………….. Exhibit 3

Gas Cost Recovery Charge…………………………………………………. Exhibit 4

Gas Energy Efficiency Charge……………………………………………… $0.417/Dth[697]

VII. Hearing

On November 15, 2012, following notice duly provided in accordance with R.I. General Laws, the Commission held a hearing on the merits of the Amended Settlement Agreement. The following appearances were entered:

FOR NATIONAL GRID:	Thomas Teehan, Esq. Cheryl M. Kimball, Esq. Celia B. O'Brien, Esq.
FOR THE DIVISION:	Leo Wold, Esq. Steve Scialabba, Rate Analyst David J. Effron, Division Consultant
FOR THE COMMISSION:	Amy K. D'Alessandro, Esq. Alan Nault, Utility Rate Analyst

National Grid witness, Michael Laflamme, and Division consultant, David Effron, reviewed the terms and provisions of the Amended Settlement Agreement and answered questions posed by the Commission. Mr. Laflamme testified that the only difference between the original settlement agreement filed with the Commission on October 19 and the Amended Settlement Agreement filed November 14 was a $3.0 million increase in the electric cost of service.[698] This $3 million increase represented the incremental contribution to the storm fund to

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[695] Based on typical residential heating customer consuming 846 therms per year. Compliance Filing of National Grid (01/24/13), PMN-8, p.1.
[696] Exhibit 2 is a Gas Rate Summary Sheet provided to the Commission on January 25, 2013 for reference only.
[697] Compliance Filing of National Grid (01/24/13), Compliance Attachment 12, p.1.
[698] Transcript, p.12.

address the anticipated repair costs associated with Hurricane Sandy.[699] He qualified this explanation by noting that actual storm costs expended on restoration and repair associated with Hurricane Sandy would be subject to Commission review and approval in accordance with existing Commission practice and that the $3 million increase in the electric cost of service did not represent a pre-approval of storm expenditures.[700]

The Commission asked Mr. Laflamme whether the Company's change to a regional structure was perceived as a benefit particularly with regard to restoration efforts following Hurricane Sandy.[701] Mr. Laflamme admitted that although the regional structure had not worked as well as the Company had hoped with regard to Hurricane Sandy, he was adamant that the regional view is the most efficient way to handle storm response.[702] The Commission asked whether two Consumer Advocate positions which had been included in the original filing were included in the Amended Settlement Agreement. Mr. Laflamme stated that the funding for the two Consumer Advocates had been excluded from the Amended Settlement Agreement but that the Company may still hire the two consumer advocates.[703]

The fact that the uncollectible rate has been steadily increasing over the years was addressed at the hearing. Division witness, David Effron, testified that the Division was comfortable with the uncollectible rates agreed to in the Amended Settlement.[704] The Commission questioned whether Mr. Oliver's concerns regarding decoupling were addressed in the Settlement. Mr. Oliver was concerned about cross-subsidization caused by revenue decoupling and argued in favor of a class specific RDM factor. Mr. Effron testified that although

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[699] Id.
[700] Id., p.12.
[701] Id., p.26.
[702] Id., pgs.27-28.
[703] Id., pgs.42-47.
[704] Id., p.51.

the Amended Settlement Agreement calls for a per unit RDM charge, and some cross subsidization will most likely occur from the operation of this charge, the Division notified Mr. Oliver of all settlement negotiations and all issues involving rate design.[705] It was suggested that Mr. Oliver's failure to object to any of the terms and provisions of the Amended Settlement should be indicative of his approval of the same.[706] Mr. Laflamme further suggested that cross subsidization is inevitable and even appropriate in the operation of revenue decoupling, given the policies upon which it is based. Since the policy behind decoupling is to remove the Company' disincentive to promote energy conservation, rather than imposing the RDM charge on the customer who conserves energy, Mr. Laflamme stated, "…the idea of spreading that usage response to the entire population of ratepayers seems to be more in line with what the whole revenue decoupling policy rationale is intended to do."[707]

Mr. Laflamme testified that although the 9.5% ROE was considerably lower than other ROEs approved in recent regulatory decisions, it was an ROE that ultimately the Company was willing to accept.[708] Mr. Effron also testified that to his knowledge, the 9.5% ROE agreed upon in this Amended Settlement was in the low end of the range of recently approved ROEs and, therefore, satisfies Rhode Island's statutory mandate of being "within the norm of industry standards."[709] The Commission asked Mr. Laflamme why the pension adjustment mechanism was necessary. Mr. Laflamme explained that the Company's pension costs are largely dictated by circumstances, such as actuarial assumptions and interest rates, that are beyond the control of the Company.[710] Since the nature of pension costs are forward looking, requiring the Company

[705] Id., p.56.
[706] Id.
[707] Id., p.58.
[708] Id., pgs.66-67.
[709] Id., pgs.70-71; R.I.G.L. §39-1-27.7.1(b).
[710] Id., p.72.

to project costs well into the future, they are often volatile, which make them more suitable for annual reconciliations.[711] Mr. Laflamme noted that pension adjustment mechanisms have been implemented in two of the Company's other jurisdictions, Massachusetts and New York, and are fairly common throughout the Company.[712] He further noted that pension adjustment mechanisms serve the interests of the customer as well as the Company, insofar as they limit the customer's exposure to a specified level of annual pension and post-retirement benefit costs.[713]

Mr. Laflamme reviewed the property tax recovery mechanism and how it will operate. He explained that in the most recent ISR filing, the Company and the Division disputed whether the Company should factor depreciation on embedded plant in the Company's property tax recovery.[714] The Division felt the Company's depreciation expense on embedded plant should be included in the calculation of its property tax recovery.[715] The Company argued that its property tax expense depends on both property valuation and property tax rates, and recovery of this expense should take both factors into consideration.[716] The property tax recovery mechanism agreed to in the Amended Settlement takes into consideration both the valuation of property and property tax rates.[717] It also excludes gas growth capital which amounts to approximately $10 million invested each year to connect new customers.[718] Considering the fact that the property tax recovery mechanism originally proposed by the Company would have included gas growth capital and would not have taken into account depreciation on embedded plant, Mr. Laflamme characterized the agreed upon property tax recovery mechanism as "not a full tracker

[711] Id., pgs. 72-73.
[712] Id., p.74.
[713] Id.
[714] Id.,
[715] Id., p.81.
[716] Id.,pgs.81-82.
[717] Id.
[718] Id., pgs.82-83.

mechanism."[719] Division witness, David Effron, agreed with this assessment, adding that the property tax recovery mechanism agreed to in the Amended Settlement should mitigate the shifting of risk from the Company to the customer which was one of the concerns expressed in his pre-filed testimony.[720]

The Company explained that for purposes of bill impact analyses, typical residential gas consumption had been changed from 922 therms to 846 therms. Ann Leary testified on behalf of National Grid that the previous annual gas consumption used by the Company for its bill impact analyses, 922 therms, was based on use per customer in 2007.[721] Ms. Leary explained that the annual consumption of 922 therms was updated to reflect a recent declining trend in energy consumption due to energy efficiency.[722] The Commission questioned whether the inclusion of the uncollectible factor in the energy efficiency charge would affect energy efficiency funding.[723] Mr. Laflamme stated that the uncollectible factor would have no impact on energy efficiency program funding.[724]

The Company was asked to review the change in the Non-Firm margin threshold for gas customers. Mr. Laflamme explained the Company's present treatment of Non-firm gas customers and how it changed as a result of the Amended Settlement. He explained that currently the Company tracks both Firm and Non-Firm revenues and applies a threshold of $2.8 million to these revenues.[725] This means that the Company would either credit or charge customers for revenues collected over or under this $2.8 million threshold.[726] The Amended Settlement authorizes the Company to apply a lower threshold of $1.8 million only to Non-Firm

[719] Id., pgs.82-83.
[720] Id., p.85,91.
[721] Ann Leary is Program Manager in Gas Pricing for National Grid. Id., p.93.
[722] Id., p.94.
[723] Id., p.97.
[724] Id., pgs.98-99.
[725] Id., pgs.101-102
[726] Id.

customers.[727] To address migration into or out of the Non-Firm class, the $1.8 million would be adjusted accordingly to reflect the migrating customer's contribution.[728] For instance, if a Non-Firm customer migrates to Firm, the $1.8 million threshold would be adjusted downward to reflect that migration and to avoid the Company essentially double recovering for this customer.[729] Similarly, when a Firm customer migrates to the Non-Firm class, the $1.8 million threshold would be adjusted upwards to account for that migration.[730]

VIII. Decision

At an Open Meeting held on December 20, 2012, the Commission reviewed and discussed the merits of the Amended Settlement Agreement filed November 14, 2012.
The R.I. General Laws require utility rates to be reasonable and just.[731] The general laws recognize the utility's need to maintain financial health and to provide safe, reasonable and adequate services and facilities.[732] The Commission is tasked with determining whether the Amended Settlement Agreement complies with these mandates and whether it is just, fair and reasonable, in the public interest or otherwise in accordance with law and regulatory policy.[733]

The bill increases associated with the Amended Settlement are $2.56 per month for an average residential electric customer and $55.00 per year for a typical residential gas heating customer. These impacts are considerably lower than the bill impacts associated with the Company's original proposal and reflect the close collaboration which occurred in this docket between the Division and National Grid. The rate increase originally proposed by the Company was $31 million for its electric distribution operations and $19 million for gas distribution

[727] Id., pgs.103-104.
[728] Id., p.104.
[729] Id.
[730] Id., p.104.
[731] R.I.G.L. §39-2-1(a).
[732] Id; R.I.G.L. §39-1-27.7.1(b).
[733] R.I.P.U.C. Rule 1.24(b)(5).

operations. The impacts associated with this increase would have been $3.97 per month and $98.00 per year for electric and gas distribution operations, respectively. To the extent that the present bill impacts are considerably lower than those associated with the Company's original proposal, the Amended Settlement Agreement clearly mitigates the effects of the rate increase on ratepayers and is consistent with the statutory mandate for just and reasonable rates.

The Commission finds that the Amended Settlement Agreement recognizes the utility's financial health and obligation to provide safe, reasonable and adequate services.[734] Both Mr. Laflamme and Division witness, David Effron, testified that the agreed upon ROE is in the lower range of ROEs authorized in recent regulatory decisions and indeed within the norm.[735] The record reflects that the Company accepted a lower ROE in exchange for other provisions such as property tax and pension recovery, albeit not on the exact terms proposed by the Company. The Division was extensively involved in negotiating this Amended Settlement Agreement and has executed the same, indicating its unqualified approval on behalf of ratepayers. In light of the foregoing, the record supports a finding that the Amended Settlement Agreement is just, fair and reasonable and otherwise in accordance with R.I. General Laws and regulatory policy. The Commission, accordingly, finds the same is just, fair and reasonable and consistent with R.I. General Laws and regulatory policy, and approves the same in its entirety. The Amended Settlement Agreement represents a balanced approach to addressing the competing interests of the ratepayer and the utility recognized in the General Laws. The Amended Settlement Agreement mitigates bill impacts for gas and electric ratepayers and maintains the utility's financial health and obligation to provide safe, reasonable and adequate services, consistent with R.I.G.L. §39-2-1 and §39-1-27.7.1(b). All electric and gas distribution rates, charges and tariffs

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[734] R.I.G.L. §39-1-27.7.2(b).
[735] Transcript, pgs. 70-71. COMM 8-1 also indicates 9.5% is considerably lower than recent regulatory decisions.

filed by National Grid on January 24, 2013, in compliance with the Amended Settlement Agreement, are just, fair and reasonable, consistent with R.I. General Laws and regulatory policy and are hereby approved.

ACCORDINGLY, it is

(21011) ORDERED:

1. The Amended Settlement Agreement, including all schedules and attachments, executed by the Narragansett Electric Company, d/b/a National Grid, the Division of Public Utilities and Carriers and the U.S. Navy, filed November 14, 2012, is hereby approved in its entirety;[736]
2. All rates, charges and tariffs filed by the Narragansett Electric Company d/b/a National Grid on January 24, 2013, pursuant to the Amended Settlement Agreement, are hereby approved for effect on February 1, 2013;
3. Until further Order of the Commission, any and all rates charged by the Narragansett Electric Company, d/b/a National Grid shall comply with the terms and provisions of the Amended Settlement Agreement filed November 14, 2012 and the tariffs filed on January 24, 2013;
4. The Narragansett Electric Company, d/b/a National Grid's revenue requirement for electric operations in the amount of $259,948,385 is hereby approved for the rate year, or the twelve month period from February 1, 2013 through January 31, 2014, and until otherwise amended and approved by the Commission;
5. The Narragansett Electric Company, d/b/a National Grid's revenue requirement for gas operations in the amount of $166,765,895 is hereby approved for the rate year, or

[736] All rates and tariffs included in the Amended Settlement Agreement filed November 14, 2012 are superseded by the rates and tariffs approved in the Compliance Filing dated January 24, 2013.

the twelve month period from February 1, 2013 through January 31, 2014, and until otherwise amended and approved by the Commission;

6. The Narragansett Electric Company d/b/a National Grid is authorized to increase electric base distribution rates by $20,925,482 and allocate such increase among all rate classes in accordance with the updated Allocated Cost of Service Study, rate design and tariffs filed with the Commission on January 24, 2013;
7. The Narragansett Electric Company d/b/a National Grid is authorized to increase gas base distribution rates by $10,898,619 for all rate classes in accordance with the updated Allocated Cost of Service Study, rate design and tariffs filed with the Commission on January 24, 2013;
8. The Narragansett Electric Company, d/b/a National Grid is authorized to earn a 9.5% return on equity on all revenues associated with electric and gas operations in the rate year, or the twelve month period from February 1, 2013 through January 31, 2014, and until otherwise ordered by the Commission;
9. The Narragansett Electric Company, d/b/a National Grid is authorized to reinstate the Storm Fund accrual in base rate cost of service at the rate of $1,800,000 annually, effective February 1, 2013. The Company shall eliminate the Storm Cost Recovery Factor but shall credit the Storm Fund in the amount of $2,500,000 beginning on January 1, 2014. The Company is further authorized to contribute an additional $3,000,000 to the Storm Fund annually for a period of six years, commencing on February 1, 2013;
10. Narragansett Electric Company d/b/a National Grid is authorized to implement a pension adjustment mechanism for its electric distribution operations, effective

February 1, 2013, on the terms prescribed in the Amended Settlement Agreement filed November 14, 2012;

11. Narragansett Electric Company d/b/a National Grid is authorized to annually recover property tax expense through the Infrastructure, Safety and Reliability Plan on the terms indicated in the Amended Settlement Agreement filed November 14, 2012.

EFFECTIVE AT WARWICK, RHODE ISLAND ON FEBRUARY 1, 2013

PURSUANT TO OPEN MEETING DECISIONS ON DECEMBER 20, 2012 AND JANUARY 31, 2013. WRITTEN ORDER ISSUED APRIL 11 , 2013.

PUBLIC UTILITIES COMMISSION

Elia Germani, Chairman

Mary E. Bray, Commissioner

Paul J. Roberti, Commissioner