BEFORE THE

RHODE ISLAND PUBLIC UTILITIES COMMISSION

APPLICATION OF THE NARRAGANSETT ELECTRIC COMPANY D/B/A NATIONAL GRID FOR APPROVAL OF A CHANGE IN ELECTRIC AND GAS BASE DISTRIBUTION RATES PURSUANT TO R.I.G.L. SECTIONS 39-3-10 AND 39-1-3-11	))))))))	**DOCKET NO. 4323**

Direct Testimony and Exhibits of

Ali Al-Jabir

On behalf of

The U.S. Department of the Navy

August 30, 2012

BRUBAKER & ASSOCIATES, INC.

Project 9648

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Table of Contents to the
Direct Testimony of Ali Al-Jabir

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Direct Testimony of Ali Al-Jabir

Introduction

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A My name is Ali Al-Jabir and my business address is 6810 Saratoga Boulevard, Suite 202, Corpus Christi, Texas, 78414.

Q WHAT IS YOUR OCCUPATION?

A I am an energy advisor and a consultant in the field of public utility regulation with the firm of Brubaker & Associates, Inc. ("BAI").

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A These are set forth in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A I am testifying on behalf of the United States Department of the Navy ("Navy"). The Navy is a large consumer of electricity in the service territory of the Narragansett

Electric Company ("Company") and takes electric service from the Company primarily on Rate Schedule G-62.

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A My testimony focuses on the portions of National Grid's filing that address the Company's electric cost of service. The purpose of my testimony is to discuss the Company's electric class cost of service study ("CCOSS"), proposed revenue distribution and proposed riders. The fact that I am not addressing a specific issue in the Company's application in this proceeding or that I am not addressing gas cost of service issues should not be construed as an endorsement of the Company's position with regard to such issues.

Q PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A My conclusions and recommendations can be summarized as follows:

1. The Rhode Island Public Utilities Commission ("Commission") should reject the Company's proposal to allocate meter data services expenses, retail marketing costs and customer installation expenses on the basis of energy consumption. These costs are customer-related rather than energy-related. Therefore, the Company's proposed allocation method for these costs is inconsistent with cost-causation principles. Instead, these costs should be allocated to the customer classes on the basis of customer counts.

2. It is inappropriate to allocate all of the Demonstration and Selling expenses in Account 912 exclusively to Commercial and Industrial customers. A subset of the activities recorded to Account 912 is targeted to all customers on the Company's system and should therefore be allocated to all customer classes on the basis of customer counts.

3. The Company's proposal to cap the revenue increase for all customers in the 3,000 kW Rate B/G-62, Lighting and Propulsion classes at two times the system average increase would impose an undue burden on large customers that could adversely impact the economic climate in Rhode Island. Therefore, the revenue distribution should be modified to cap the rate increase for customers with demands greater than 8 MW at 150% of the system average rate increase. The rate increase for other customers in the 3,000 kW Rate B/G-62, Lighting and Propulsion classes should be capped at twice the system average increase. This

approach is consistent with the precedent on revenue distribution established by the Commission in the Company's most recent electric base rate case.

4. The Commission should reject the Company's proposal to recover commodity-related uncollectible expenses, pension costs and property tax expenses using tracking mechanisms. The expansion of existing trackers and the implementation of new riders would be inappropriate because these riders would result in piece-meal ratemaking and they would transfer traditional business risks from the Company's shareholders to its customers. Moreover, the Company's reliance on a forecasted rate year to develop its rate applications and the implementation of revenue decoupling significantly reduce the need for additional tracker mechanisms.

5. If the Commission determines that it is appropriate to implement new riders to recover storm costs, pension costs and property tax expenses, the Commission should reject the Company's proposal to recover these costs from all customers through a uniform per kWh charge. Instead, the costs recovered through each of these riders should be allocated to the customer classes on the same basis that these cost items are allocated in the Company's electric CCOSS. This approach would be more consistent with cost-causation principles and ensure consistent allocation of these costs between the Company's base rates and tracking mechanisms.

6. The rider charges for transmission costs, storm costs, pension costs and property tax expenses should be designed and assessed on a demand (per kW) basis rather than on an energy (per kWh) basis for rate classes that possess demand metering. Given that the incurrence of the costs in question bears no relationship to customer class energy usage, a per-kW rate design would be more appropriate for these riders where such a rate design is feasible.

Cost of Service Overview

Q HAS THE COMPANY FILED AN ELECTRIC CCOSS IN THIS PROCEEDING?

A Yes.

Q WHAT INFORMATION IS CONTAINED IN A CCOSS?

A A CCOSS is used to determine the cost that the Company incurs to serve the various customer classes in its service territory. A CCOSS compares the cost that each customer class imposes on the system to the revenues that each class contributes.

This relationship is generally presented by comparing the rate of return that a class is providing to the utility's overall jurisdictional rate of return.

For example, when a customer class produces the same rate of return as the total utility rate of return, the customer class is paying revenue to the utility just sufficient to cover the costs that the utility incurs to serve that class. If a class produces a below-average rate of return, it may be concluded that the revenue provided by the class is insufficient to cover all relevant costs to serve that class. On the other hand, if a class produces a rate of return above the system average, it is not only paying revenues sufficient to cover the cost attributable to it, but in addition, it is paying part of the cost attributable to other classes who produce below system average rates of return.

Q WHY IS A CCOSS OF IMPORTANCE?

A A CCOSS illustrates the costs that a utility incurs to serve each customer class. It is a widely held principle that costs should be allocated among customer classes on the basis of cost causation. That principle is perhaps the most universally accepted tenet of allocating costs that cannot be directly assigned to a particular customer class. In other words, costs should be allocated to those classes on the basis of how or why those costs are incurred by the utility. The results of such studies are used in assigning cost responsibilities to various customer classes in regulatory proceedings.

Q DO YOU SUPPORT THE PREMISE THAT COST-CAUSATION PRINCIPLES SHOULD GUIDE THE ALLOCATION OF COSTS TO THE CUSTOMER CLASSES?

A Yes. Rates that are based on consistently applied cost-causation principles are not only fair and reasonable, but further the cause of stability, conservation and efficiency. When consumers are presented with price signals that convey the consequences of their consumption decisions (i.e., how much energy to consume, at what rate, and when), they tend to take actions which not only minimize their own costs, but those of the utility as well.

Although factors such as simplicity, gradualism, economic development and ease of administration can also be taken into consideration when determining the final spread of the revenue requirement among classes, the fundamental starting point and guideline should be the cost of serving each customer class produced by the CCOSS.

Q HOW IS THE COST OF SERVING EACH CUSTOMER CLASS DETERMINED?

A The appropriate mechanism to determine the cost of serving each customer class is a fully allocated embedded CCOSS. It follows, however, that the objective of cost-based rates cannot be attained unless the CCOSS is developed using cost-causation principles.

Q WHAT ARE THE MAJOR STEPS IN A CCOSS?

A The first step in a CCOSS is known as <u>functionalization</u>. This refers to the process by which the Company's investments and expenses are reviewed and put into different categories of cost. The primary functions utilized are production, transmission and distribution. Of course, each broad function may have several subcategories to provide for a more refined determination of cost of service.

The second major step is known as <u>classification</u>. In the classification step, the functionalized costs are separated into the categories of demand-related, energy-related and customer-related costs in order to facilitate the allocation of costs by applying cost-causation principles.

Demand- or capacity-related costs are those costs that are incurred by the utility to serve the amount of demand that each customer class places on the system. A traditional example of capacity-related costs is the investment associated with generating stations, transmission lines and a portion of the distribution system. Once the utility makes an investment in these facilities, the costs continue to be incurred, irrespective of the number of kilowatthours generated and sold or the number of customers taking service from the utility.

Energy-related costs are those costs that are incurred by the utility to provide the energy required by its customers. Energy-related costs, such as fuel expense, are almost directly proportional to the amount of kilowatthours supplied by the utility system to meet its customers' energy requirements. As a general rule, delivery service costs are not energy-related.

Customer-related costs are those costs that are incurred to connect customers to the system and are independent of the customer's demand and energy requirements. Primary examples of customer-related costs are investments in meters, services and the portion of the distribution system that is necessary to connect customers to the system. In addition, such accounting functions as meter reading, bill preparation and revenue accounting are considered customer-related costs.

The final step in the CCOSS is the allocation of each category of the functionalized and classified costs to the various customer classes using cost-causation principles. Demand-related costs are allocated on a basis that gives recognition to each class's responsibility for the Company's need to build plant or to procure capacity to serve the demands imposed on the system. Energy-related costs are allocated on the basis of energy use by each customer class. Customer-related costs are allocated based upon the number of customers in each class, weighted to account for the complexity of servicing the needs of the different classes of customers.

Q WHY IS IT IMPORTANT TO ADHERE TO BASIC COST OF SERVICE PRINCIPLES IN THE RATEMAKING PROCESS?

A The basic reasons for using cost of service as the primary factor in the revenue allocation/rate design process are equity, cost causation, appropriate price signals, conservation and revenue stability.

Q HOW IS THE EQUITY PRINCIPLE ACHIEVED BY BASING RATES ON COSTS?

A To the extent practical, when rates are based on cost, each customer pays what it costs the utility to serve them, no more and no less. If rates are not based on cost of service, then some customers contribute disproportionately to the utility's revenue requirement and provide contributions to the cost to serve other customers.

Q HOW DO COST-BASED RATES PROVIDE APPROPRIATE PRICE SIGNALS TO CUSTOMERS?

A Rate design is the process of translating the cost of providing service for each customer class into per unit charges that recover the targeted revenue requirement for each class. It is important that the proper amounts and types of costs be allocated to the appropriate customer classes so that they may ultimately be reflected in the rates.

When the rates are designed so that the demand, energy, and customer costs are properly reflected in the demand, energy and customer components of the rate schedules, respectively, customers are provided with the appropriate price signals to manage their loads accordingly. This, in turn, provides the correct signal to the utility (and other competitive power suppliers if applicable) regarding the need for new investment to meet the customers' needs. When customers impose a certain level of demand on the system, they should pay for the prudent cost that the utility incurs to supply that demand and the energy charge that they pay should reflect the cost of providing that energy.

From a rate design perspective, overpricing one portion of the rate (i.e., energy) and under pricing the other components of the rate, such as customer and demand charges, will result in a disproportionate share of revenues being collected from high load factor customers and send distorted price signals to all customers.

Q HOW DO COST-BASED RATES FURTHER THE GOAL OF CONSERVATION?

A Conservation occurs when wasteful or inefficient uses of electricity are discouraged or minimized. Only when rates are based on the cost to serve them do customers receive an accurate and appropriate price signal against which to make their consumption decisions. If rates are not based on costs, then customers may be induced to use electricity inefficiently in response to the distorted price signals.

Q PLEASE DISCUSS THE REVENUE STABILITY CONSIDERATION.

A Rates that are designed to track changes in the level of costs result in revenue changes that mirror cost changes. Thus, cost-based rates provide an important enhancement to a utility's earnings stability, reducing its need to file for rate increases.

From the perspective of the customer, cost-based rates provide a more reliable and transparent means of determining future levels of power costs. If rates are based on factors other than the cost to serve, the correlation between utility cost fluctuations and rate adjustments becomes weaker. This makes it difficult for customers to translate utility-wide cost changes into the fluctuations that they witness in their rates. For the customer, this situation reduces the attractiveness of expansion, as well as continued operations, in the utility's service territory because of the limited ability to plan and budget for the level of future power costs that the customer will incur.

The Company's Cost of Service Study

Q PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S ELECTRIC CCOSS.

A The Company presented a traditional, embedded CCOSS that was used to establish the level of revenues necessary for each customer class to provide a return on rate base equal to the overall rate of return. The Company developed an electric CCOSS for the following customer classes: Residential, Small C&I, General C&I, C&I 200 kW Demand, C&I 3,000 kW Demand, Lighting and Propulsion. The rate year used for the CCOSS is the 12-month period ending January 31, 2014.

Q DO YOU DISAGREE WITH ANY ASPECTS OF THE COMPANY'S CCOSS AND REVENUE DISTRIBUTION?

A Yes. I take exception to the Company's proposal to allocate certain cost items on the basis of energy (either at the source or at the meter). These items include

Miscellaneous General Expenses, Customer Installation Costs and Retail Marketing Costs. The Company has not presented any persuasive evidence that establishes a causal linkage between the incurrence of these cost items and customer class energy consumption.

I also disagree with the Company's proposal to allocate Demonstration and Selling expenses in Account 912 exclusively to Commercial and Industrial customers. A subset of the costs recorded to Account 912 is targeted to all customers and should therefore be allocated to all customer classes on the basis of customer counts.

I would also note that I do not agree with the Company's proposed classification and allocation of distribution poles and wires costs. Specifically, I disagree with the Company's allocation of the costs associated with investments in Plant Accounts 364 - 368. The costs associated with these accounts should be classified and allocated based on both demands and customer counts. By contrast, the Company proposes to allocate distribution poles and wires costs in Accounts 364 - 368 entirely on a demand basis. However, in the Company's most recent electric base rate case, RIPUC Docket No. 4065, the Commission declined to require the Company to develop a minimum system study to classify a portion of the Company's distribution poles and wires costs on the basis of customer counts. Therefore, while I continue to disagree with the Company's approach to classifying and allocating these costs, I will not be addressing this issue in my testimony in the current proceeding.

With respect to revenue distribution, I disagree with the Company's proposal to cap the rate increase for all customers in the 3,000 kW Rate B/G-62, Lighting and Propulsion classes at twice the system average increase. It would be more appropriate to cap the rate increase for customers with demands greater than 8 MW at 150% of the system average rate increase approved by the Commission in this case, while capping the rate increase for all other customers in the 3,000 kW Rate B/G-62, Lighting and Propulsion classes at two times the system average increase. These points are addressed in more detail in subsequent sections of my direct testimony.

Changes to the Company's Proposed Allocation Methods

Q IS THE COMPANY PROPOSING TO ALLOCATE CERTAIN COST ITEMS ON AN ENERGY BASIS IN ITS ELECTRIC CCOSS?

A Yes. The Company is proposing to allocate to the customer classes a number of cost items on the basis of either energy at the source or energy at the meter. My testimony focuses on certain cost allocations as set forth below:

- Miscellaneous General Expenses – MWh at the generator
- Distribution Operations Customer Installation Costs – MWh at the meter
- Customer Service Retail Marketing Costs – MWh at the meter[1]

Q WHAT SPECIFIC COSTS COMPRISE THE MISCELLANEOUS GENERAL EXPENSES THAT THE COMPANY INCLUDED IN ITS COST OF SERVICE IN THIS PROCEEDING?

A In response to discovery in this case, the Company stated that the $2.192 million of Miscellaneous General Expenses are comprised of environmental remediation and compliance costs (90% of the total) and meter data services (10% of the total).[2]

[1]Docket No. 4323, Direct Testimony of Howard S. Gorman, Schedules HSG-1G, HSG-3M and HSG-3N.

[2]Docket No. 4323, Narragansett Electric Company's data response Navy 1-11-ELEC.

Q IS IT REASONABLE TO ALLOCATE MISCELLANEOUS GENERAL EXPENSES ENTIRELY ON AN ENERGY BASIS?

A No. The Company's proposed allocation of meter data services costs is not supported by principles of cost-causation, as metering costs do not vary as a function of customer class energy consumption. Rather, the incurrence of metering costs is more closely related to the number of customers on the Company's system. Therefore, it would be more appropriate to allocate meter data services costs based on customer counts. In its data response, the Company conceded that it would be reasonable to allocate the meter data services portion of Miscellaneous General Expenses, which constitutes roughly $220,000 of costs, based on meter costs or the number of customers.[3]

Q PLEASE DESCRIBE THE CUSTOMER SERVICE RETAIL MARKETING COSTS THAT THE COMPANY INCLUDED IN ITS COST OF SERVICE IN THIS PROCEEDING.

A In response to discovery, the Company stated that these marketing costs are incurred in support of retail access. According to the Company's Schedule NG-HSG-3M, the Company included $112,050 in costs for this line item in Account 910.[4]

Q IS IT APPROPRIATE TO ALLOCATE THESE MARKETING COSTS ON AN ENERGY BASIS?

A No. It appears that these marketing costs involve outreach to customers on the Company's system and responding to inquiries from customers regarding direct access issues. Therefore, this activity is essentially a customer support function that

[3]Ibid.
[4]Docket No. 4323, Narragansett Electric Company's data response Navy 1-12-ELEC.

is more directly related to customer counts rather than energy consumption. According to the NARUC Cost Allocation Manual, customer service and informational expenses in Account 910 should generally be treated as customer-related.[5] For these reasons, I recommend that customer service retail marketing costs be allocated based on customer counts.

Exhibit AZA-1 to my direct testimony calculates the impact of this recommendation on the class allocation of Customer Service Retail Marketing Costs and the resulting impacts on the class allocation of total Account 910 expenses.

Q PLEASE DESCRIBE THE DISTRIBUTION OPERATIONS – CUSTOMER INSTALLATION COSTS THAT THE COMPANY INCLUDED IN ITS COST OF SERVICE IN THIS PROCEEDING.

A In response to discovery, the Company stated that 95% of the customer installation costs included in Account 587 relate to the investigation of possible thefts of electricity.[6] According to the Company's Schedule HSG-1B, the Company included $1.424 million in costs for this cost item in Account 587.

Q IS IT APPROPRIATE TO ALLOCATE THESE CUSTOMER INSTALLATION COSTS ON AN ENERGY BASIS?

A No. Costs incurred to investigate customer theft are expected to vary most closely as a function of the number of customer thefts investigated. There is no reason to believe that the amount of energy allegedly stolen by individual customers would significantly impact the costs incurred to conduct such investigations. Therefore, the incurrence of these costs is causally related to customer counts rather than energy

[5]National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual, January 1992, p. 103.
[6]Docket No. 4323, Narragansett Electric Company's data response Navy 1-11-ELEC.

usage. According to the NARUC Cost Allocation Manual, expenses accrued to Account 587 should be treated as customer-related rather than energy-related.[7] For these reasons, I recommend that Distribution Operations – Customer Installation costs be allocated based on customer counts.

Q PLEASE DISCUSS YOUR CONCERNS REGARDING THE COMPANY'S PROPOSED ALLOCATION OF DEMONSTRATION AND SELLING EXPENSES.

A The Company allocated approximately $1.2 million in Demonstration and Selling expenses exclusively to Commercial and Industrial customers on the basis of customer counts.[8] However, in response to data requests, the Company indicated that a subset of the costs recorded to this account (in the amount of $521,453) is associated with general customer outreach and education efforts in areas such as safety, storm preparedness, billing information and financial assistance. These activities inure to the benefit of all customer classes, not just Commercial and Industrial customers. Therefore, the Company's proposal to allocate these costs only to Commercial and Industrial customers is inconsistent with cost-causation principles. Instead, a portion of the costs recorded to Account 912 (in the amount of $521,453) should be broadly allocated to all customer classes on the basis of customer counts. In response to discovery, the Company conceded that these costs should have been allocated to all rate classes on a per-customer basis. The Company also revised its electric CCOSS to reflect a modified Account 912 allocator.[9]

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[7] National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual, January 1992, p. 88.

[8] Docket No. 4323, Direct Testimony of Howard S. Gorman, Schedule HSG-1F-5, page 3.

[9] Docket No. 4323, Narragansett Electric Company's data response Division 21-4(d)-ELEC (Supplemental).

Q HAVE YOU REVISED THE COMPANY'S PROPOSED ELECTRIC CCOSS TO REFLECT YOUR RECOMMENDED ALLOCATION OF THE COST ITEMS DISCUSSED ABOVE?

A Yes. Exhibit AZA-2 provides the summary results of the electric CCOSS using my recommended allocation of these cost items.

Revenue Distribution

Q HAVE YOU REVIEWED THE RESULTS OF THE ELECTRIC CCOSS WITH REGARD TO CLASS REVENUE DISTRIBUTION?

A Yes. I reviewed the results of the electric CCOSS for the rate year ending January 31, 2014. The results of the CCOSS are summarized in Exhibit AZA-2. This exhibit shows the CCOSS results at present and proposed rates, both under the Company's proposal and under the modified CCOSS that reflects my recommended modifications to the Company's proposed allocators. The CCOSS results include the rate of return, the relative rate of return index, and the revenue under- or over-collection.

Q HOW CAN THE CCOSS RESULTS BE INTERPRETED WITH RESPECT TO THE REVENUE CONTRIBUTION OF EACH CLASS RELATIVE TO ITS COST OF SERVICE?

A The rates of a customer class are set at cost of service when the relative rate of return index of the class is 100. At that level, the rate of return derived from the class is equal to the system rate of return. A customer class has a revenue under-collection when the revenues provided through its rates are less than the cost to serve that class, resulting in a class relative rate of return index below 100.

Conversely, a customer class has a revenue over-collection when the revenues collected from the class are greater than the cost to serve that class, resulting in a relative rate of return index greater than 100.

Q HOW DOES THE COMPANY PROPOSE TO DISTRIBUTE THE PROPOSED REVENUE INCREASE AMONG THE CUSTOMER CLASSES?

A Exhibit AZA-3 shows the Company's proposed revenue increase by amount and as a percentage of present revenue for each customer class. For comparison purposes, the exhibit also shows the rate increases that would result from a direct application of the results of the CCOSS in this proceeding. As can be seen in the exhibit, the Company proposes to cap the rate increase for the 3,000 kW Demand, Lighting and Propulsion classes at twice the system average increase.

Q HOW DOES THE COMPANY'S REVENUE DISTRIBUTION PROPOSAL COMPARE TO THE ACTUAL COST TO SERVE EACH RATE CLASS, AS INDICATED BY THE CCOSS RESULTS?

A As shown in Exhibit AZA-2, the Company's proposed revenue distribution results in a relative rate of return approximately equal to 100 for the Residential class. The relative rate of return is greater than 100 for the Small C&I, General C&I and 200 kW Demand customer classes. The proposed revenue distribution yields a relative rate of return of less than 100 for the 3,000 kW Demand, Lighting and Propulsion classes.

Q IS IT APPROPRIATE TO CAP THE RATE INCREASE FOR ALL CUSTOMERS IN THE 3,000 kW DEMAND, LIGHTING AND PROPULSION CLASSES AT TWO TIMES THE SYSTEM AVERAGE INCREASE?

A No. This proposal would result in a significant delivery service rate increase of 26.3% for large customers in the Company's service territory. This increase is excessive, and the Commission should take steps to moderate the magnitude of this rate increase.

Q PLEASE EXPLAIN WHY IT IS APPROPRIATE TO LIMIT THE MAGNITUDE OF RATE INCREASES FOR LARGE CUSTOMERS ON THE COMPANY'S SYSTEM.

A In determining the revenue distribution in this proceeding, the Commission should recognize the harm that large electric rate increases of this magnitude can inflict on the economic base in the state of Rhode Island. Large customers on the Company's system make important contributions to the economic health of the state directly through their payrolls and tax revenues, as well as indirectly through their purchase of goods and services from local suppliers. Large electric rate increases have the potential to adversely impact these economic contributions by making it more costly for large customers to operate in Rhode Island. For these reasons, the Commission should restrict the size of the rate increase proposed by the Company for large customers.

Q HAS THE COMMISSION PREVIOUSLY RECOGNIZED THAT THE RATE INCREASES FOR LARGE CUSTOMERS MERIT ADDITIONAL MITIGATION?

A Yes. In its Order in RIPUC Docket No. 4065, the Commission determined that it was appropriate to limit the distribution rate increase for customers with demands greater than 8 MW to 150% of the average overall rate increase approved by the Commission. In that same proceeding, the Commission ordered that the rate increase for the Lighting class be capped at two times the system average increase.[10]

Q WHAT IS YOUR RECOMMENDATION REGARDING THE DISTRIBUTION OF ANY REVENUE INCREASE IN THIS PROCEEDING?

A I recommend capping the rate increase for customers with demands greater than 8 MW at 150% of the system average rate increase. The rate increase for other customers in the 3,000 kW Rate B/G-62, Lighting and Propulsion classes should be capped at twice the system average increase. This approach appropriately mitigates the impact of the rate increase on large customers and recognizes the adverse impact that significant electric rate increases can have on the economic environment in Rhode Island. This approach is also consistent with the precedent established by the Commission on revenue distribution in the Company's most recent electric base rate case.

Introduction of New Riders

Q IS THE COMPANY PROPOSING TO IMPLEMENT ANY NEW OR EXPANDED RIDERS IN THIS PROCEEDING?

A Yes. The Company is proposing to implement new tracking adjustments in the form of a pension adjustment mechanism and a property tax adjustment. In addition, the Company proposes to expand the application of the standard offer adjustment provision to include commodity-related uncollectible expenses.

[10]RIPUC Docket No. 4065, Order No. 19965, April 14, 2010, page 19.

Q SHOULD THE COMMISSION APPROVE THE INTRODUCTION OF THESE ADDITIONAL OR EXPANDED RIDERS IN THIS PROCEEDING?

A No. As a matter of policy, the Commission should limit the use of riders and tracking mechanisms because they shift regulatory risk from the Company's investors to its customers. Moreover, such mechanisms allow the Company to recover certain components of its revenue requirement on a piece-meal basis, outside of a full base rate case. This would undermine the Commission's ability to evaluate the sufficiency of the Company's rates based on the totality of the utility's costs and revenues.

Q WHY SHOULD THE COMMISSION LIMIT THE RECOVERY OF COSTS OUTSIDE OF A BASE RATE CASE?

A To reflect changes in these cost and revenue items in rates in a traditional base rate case, the Company must establish a base rate revenue deficiency through an examination of all of the utility's costs and revenues. To establish a base rate revenue deficiency, the Company must account for all of its costs and revenues, including both increases and reductions, since the time its base rates were last approved. This is accomplished by taking a snapshot of all of the utility's costs and revenues for a designated test year, adjusted for known and measurable changes. In a full rate proceeding, no single cost or revenue item is singled out for guaranteed recovery.

The recognition of fluctuations in specific cost items through separate tracking mechanisms would circumvent the base ratemaking process by allowing the Company to adjust its rates for variations in these cost items without taking into account the possibility that increases in these costs items could be offset by reductions in other components of the Company's cost structure or increases in revenues. Therefore, the use of tracking mechanisms to recover fluctuations associated with specific cost items on an isolated basis could allow the Company to increase its rates and earn more than its authorized rate of return, without establishing a base rate revenue deficiency in a base rate proceeding.

Q PLEASE EXPLAIN WHY TRACKING MECHANISMS UNREASONABLY SHIFT RISK FROM UTILITY INVESTORS TO CUSTOMERS.

A A policy that permits a utility to adjust its rates for individual cost items outside of a base rate case shifts regulatory risk from utility investors to customers by providing investors with accelerated recognition of specific cost adjustments in utility rates. Moreover, this change in the Company's risk profile would occur without a corresponding reduction to its rate of return to recognize the reduced business risks faced by the utility.

Q WHAT ARE THE RAMIFICATIONS OF TRANSFERRING THIS REGULATORY RISK FROM INVESTORS TO RATEPAYERS?

A When investors bear the risk of regulatory lag, the utility's management has a strong incentive to control cost escalations. This is the case because any cost increases damage the utility's bottom line until the next base rate case. When the risk of cost increases between rate cases is shifted to customers through the use of tracking mechanisms, the utility's motivation to control costs is significantly reduced. This change in the incentive structure can lead to higher rates for electricity customers over time.

Q ARE THERE ANY OTHER POLICY CONSIDERATIONS THAT ARE SPECIFIC TO RHODE ISLAND THAT WOULD JUSTIFY THE REJECTION OF ADDITIONAL OR EXPANDED TRACKER MECHANISMS?

A Yes. The Company's use of a forecasted rate year to develop its cost of service diminishes the need for tracker mechanisms by allowing the Company to rely on projected costs and revenues in developing requested rates. The Company's ability to rely on projected cost data and forecasted sales revenues in developing a rate request allows the Company to incorporate expected increases in various cost items in its rate applications, thereby mitigating the need for tracking mechanisms to address these cost items. Moreover, the Company now has in place a revenue decoupling mechanism that helps to stabilize the Company's earnings and works to protect the Company from the risk of revenue fluctuations between base rate cases. These considerations further militate against the implementation of additional tracker mechanisms in this proceeding.

Q HAS THE COMMISSION PREVIOUSLY EXPRESSED POLICY CONCERNS REGARDING THE PROLIFERATION OF TRACKING MECHANISMS FOR THE COMPANY?

A Yes. In Docket No. 4065, the Commission rejected the Company's proposal to implement a reconciling mechanism for inspection and maintenance expenses. Among other reasons for its decision, the Commission objected to the Company's proposal on the basis that such a mechanism would diminish the Commission's ability to fully investigate the propriety of the underlying costs.[11]

[11] RIPUC Docket No. 4065, Order No. 19965, April 14, 2010, page 12.

Q PLEASE SUMMARIZE YOUR RECOMMENDATIONS REGARDING THE NEW OR EXPANDED TRACKING MECHANISMS THAT THE COMPANY HAS PROPOSED IN THIS PROCEEDING.

A I recommend that the Commission reject these new or expanded trackers because they would result in piece-meal ratemaking and they would inappropriately transfer traditional business risks from the Company's shareholders to its customers. Moreover, the Company's ability to rely on a forecasted rate year to develop its rate applications and the implementation of revenue decoupling for the Company significantly reduces the need for additional tracker mechanisms.

<u>Rider Rate Design</u>

Q IF THE COMMISSION NEVERTHELESS APPROVES THE NEW TRACKING MECHANISMS PROPOSED BY THE COMPANY DESPITE THE PROBLEMS IDENTIFIED ABOVE, DO YOU HAVE ANY CONCERNS REGARDING THE RATE DESIGN OF THE COMPANY'S PROPOSED NEW TRACKERS?

A Yes. The Company is proposing to recover costs under the proposed pension adjustment mechanism, the property tax adjustment provision and the storm cost recovery provision through uniform per-kWh factors that would apply to all customer classes. This results in a uniform energy-based allocation and recovery of these costs from all customers. The Commission should reject this cost allocation and rate design because it is inconsistent with cost-causation principles and contradicts the manner in which the Company allocated these items in its CCOSS.

Q PLEASE EXPLAIN WHY THE PROPOSED RATE DESIGN VIOLATES COST-CAUSATION PRINCIPLES.

A The proposed rate design contradicts cost-causation principles because there is no evidence of a causal linkage between the incurrence of these cost items and customer class energy consumption. Specifically, pension expense is a function of labor costs incurred by the Company and property taxes are a function of plant in service or rate base. Moreover, the storm costs incurred by the Company primarily relate to damage to the Company's poles and wires. These are fixed costs that are demand- and customer-related in nature. In each instance, there is no correlation between the incurrence of these cost items and energy usage on the Company's system.

Q PLEASE EXPLAIN WHY THE PROPOSED RATE DESIGN IS INCONSISTENT WITH THE COMPANY'S PROPOSED CCOSS.

A In its electric CCOSS, the Company allocated other taxes (including property taxes) as a function of plant investment.[12] Moreover, the Company allocated employee pensions and benefits in Account 926 as a function of labor costs.[13] Finally, the Company states that storm costs that are not deferred for recovery through the Company's storm contingency provision are recorded in the Company's appropriate operations and maintenance ("O&M") accounts.[14] The Company's electric CCOSS allocates O&M expense associated with the Company's poles and wires on a demand basis. In each instance, the Company's allocation of these costs in the CCOSS exhibits no linkage to customer class energy consumption. Nevertheless,

[12] Docket No. 4323, Response to the Navy's 1-10-ELEC.
[13] Docket No. 4323, Response to the Navy's 1-9-ELEC.
[14] Docket No. 4323, Response to the Navy's 1-6-ELEC.

the Company proposes to allocate and recover these same cost items through the proposed new riders entirely on an energy basis.

The underlying nature of these costs does not change simply because they are recovered through a rider rather than base rates. Therefore, there is no reason to apply a different allocation method to these costs when they are recovered through a tracker mechanism rather than base rates.

Q HAS THE COMPANY RECOGNIZED THAT THE CLASS ALLOCATION OF COSTS RECOVERED THROUGH TRACKING MECHANISMS SHOULD CONFORM TO COST-CAUSATION PRINCIPLES?

A Yes. The Company's transmission adjustment factor is currently designed as a uniform per kWh charge applicable to all rate classes. Thus, the class allocation of costs recovered through the current transmission adjustment factor is identical to the Company's proposal for the new pension, property tax and storm cost riders. In this proceeding, the Company is proposing to modify the design of the transmission adjustment factor to make it class-specific and to calculate the adjustment factor charges based on each rate class's contribution to the system peak. In support of this modified approach, Company witness Jeanne A. Lloyd testified that the Company's proposal "will more closely align rates with class cost responsibility."[15] This same objective should apply to the design of the proposed new pension, property tax and storm cost riders.

[15] Docket No. 4323, Direct Testimony of Jeanne A. Lloyd, pp. 183-184.

Q WHAT IS THE COMPANY'S RATIONALE FOR USING A FLAT PER KWH FEE TO RECOVER COSTS THROUGH THESE NEW RIDERS?

A The Company states that it does not object to designing class-specific reconciling factors, and in fact concedes that "it may be appropriate to design class-specific factors to recover or refund reconciled costs based upon a similar methodology as the design of the associated base charges." However, the Company contends that class-specific factors would add an additional level of complexity to the reconciliation process. With respect to storm cost recovery, the Company also cites the benefits of simplicity in rate design, and further asserts that a flat per kWh charge would result in an equitable allocation of storm-related expenses.[16]

Q DO YOU AGREE WITH THE COMPANY'S REASONING?

A No. Once the class allocation factors for a particular cost item are established in a base rate proceeding, it would be a straightforward matter to apply the resulting class allocation percentages for that cost item to the analogous costs recovered through a rider mechanism. If the Company is able to implement a class-specific allocation approach for transmission costs recovered through an adjustment factor, I see no valid reason why it could not implement the same basic approach for other rider mechanisms.

With respect to the equity argument raised by the Company, it should be noted that equity in class cost allocation is properly defined by the extent to which the proposed allocation tracks cost causation as established in the approved CCOSS. A uniform per kWh charge applied to all classes cannot be considered equitable if there

[16] Docket No. 4323, Responses to the Navy's 1-6-ELEC and 1-9-ELEC.

are meaningful differences in each customer class's contribution to the Company's incurrence of a particular cost item.

Q DO YOU HAVE ANY CONCERNS REGARDING THE BILLING DETERMINANTS THAT THE COMPANY USED TO DESIGN ITS RIDER CHARGES?

A Yes. The Company proposes to design the charges for the transmission cost, pension cost, property tax and storm cost riders on a per kWh basis. As discussed above, the Company's incurrence of pension costs, property taxes and storm costs bears no relationship to customer class energy consumption. The same is true for transmission costs, which are fixed in nature and driven by the system peak demands. For this reason, it would be more appropriate to design these rider charges on a per kW basis for customer classes that possess demand metering.

Q PLEASE SUMMARIZE YOUR RECOMMENDATIONS WITH RESPECT TO THE CLASS ALLOCATION AND RATE DESIGN OF THE COMPANY'S RIDER CHARGES.

A The expenses recovered through the proposed pension, property tax and storm cost riders should be allocated to the customer classes on the same basis that these cost items are allocated in the Company's electric CCOSS. This approach would be more consistent with cost-causation principles and ensure consistent allocation of these costs between the Company's base rates and tracking mechanisms. Moreover, the charges for the transmission, pension, property tax and storm cost riders should be designed and assessed on a demand (per kW) basis for rate classes that possess demand metering. Given that the incurrence of the costs in question bears no relationship to customer class energy usage, a per kW rate design would be more appropriate for these riders where such a rate design is feasible.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes.

Qualifications of Ali Al-Jabir

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Ali Al-Jabir. My business address is 6810 Saratoga Boulevard, Suite 202, Corpus Christi, Texas, 78414.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am a consultant in the field of public utility regulation with the firm of Brubaker & Associates, Inc. (“BAI”).

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND.

A I am a graduate of the University of Texas at Austin (“UT-Austin”). I hold the degrees of Bachelor of Arts and Master of Arts in Economics, both from UT-Austin. I have also completed course work at Harvard University. I received my B.A. degree with highest honors, and I am a member of the Phi Beta Kappa Honor Society.

Q PLEASE STATE YOUR EXPERIENCE.

A I joined BAI in January 1997. My work consists of preparing economic studies and economic policy analyses related to investor-owned, cooperative, and municipal utilities. Prior to joining BAI, I was employed at the Public Utility Commission of Texas (“Texas Commission”) since 1991, where I held various positions including Policy Advisor to the Chairman. As Policy Advisor, I advised the Chairman on policy decisions in numerous rate and rulemaking proceedings. In 1995, I advised the Texas Legislature on the development of the statutory framework for wholesale competition in the Electric Reliability Council of Texas (“ERCOT”), and I was involved in subsequent rulemakings at the Texas Commission to implement wholesale open access transmission service in the region.

During my tenure at the Texas Commission and in my present capacity, I have reviewed and analyzed several electric utility base rate and fuel filings in Texas. I have also worked on utility rate, fuel, and merger proceedings and rulemakings in Virginia, Missouri, Colorado, Indiana, Alberta, Pennsylvania, North Carolina, South Carolina, Michigan, Nova Scotia and Rhode Island. In addition to my work in such proceedings, I have drafted policy papers and comments regarding electric industry restructuring and competitive policy issues in Texas, Alabama, Louisiana, Georgia, and Delaware, as well as before the Federal Energy Regulatory Commission. I have been an invited speaker at several electric utility industry conferences, and I have presented seminars on utility regulation and industry restructuring. I have also advised clients on electricity procurement in competitive retail power markets.

BAI and its predecessor firms have been active in utility rate and economic consulting since 1937. The firm provides consulting services in the field of public utility regulation to many clients, including large industrial and institutional customers, some competitive retail power providers and utilities and, on occasion, state regulatory agencies. In addition, we have prepared depreciation and feasibility studies relating to utility service. We assist in the negotiation of contracts and the solicitation and procurement of competitive energy supplies for large energy users, provide economic policy analysis on industry restructuring issues, and present seminars on utility regulation. In general, we are engaged in regulatory consulting, economic analysis, energy procurement, and contract negotiation.

In addition to our main office in St. Louis, the firm also has branch offices in Corpus Christi, Texas and Phoenix, Arizona.

Q HAVE YOU PREVIOUSLY FILED TESTIMONY IN CONTESTED UTILITY PROCEEDINGS?

A Yes, I have filed written testimony in the following dockets:

1. Texas Docket No. 10035 – Application of West Texas Utilities Company to Reconcile Fuel Costs and for Authority to Change Fixed Fuel Factors;

2. Texas Docket No. 10200 – Application of the Texas - New Mexico Power Company for Authority to Change Rates;

3. Texas Docket No. 10325 – Application of the Central Texas Electric Cooperative, Inc. for Authority to Change Rates;

4. Texas Docket No. 10600 – Application of the Brazos River Authority for Approval of Rates;

5. Texas Docket No. 10881 – Application of the New Era Electric Cooperative, Inc. for Authority to Change Rates;

6. Texas Docket No. 11244 – Petition of the Medina Electric Cooperative, Inc. to Reduce its Fixed Fuel Factor and the Application of the South Texas Electric Cooperative, Inc. for Authority to Refund an Over-Recovery of Fuel Cost Revenues and to Reduce its Fixed Fuel Factor;

7. Texas Docket No. 11271 – Application of Bowie-Cass Electric Cooperative, Inc. for Authority to Change Rates;

8. Texas Docket No. 11567 – Application of Kaufman County Electric Cooperative, Inc. for Authority to Change Rates;

9. Texas Docket No. 18607 – Application of West Texas Utilities Company for Authority to Reconcile Fuel Costs;

10. Texas Docket No. 20290 – Application of Central Power & Light Company for Authority to Reconcile Fuel Costs;

11. Virginia Case No. PUE980814 – In the matter of considering an electricity retail access pilot program: American Electric Power – Virginia;

12. Texas Docket No. 21111 – Application of Entergy Gulf States Inc. for Authority to Reconcile Fuel Costs and to Recover a Surcharge for Under-Recovered Fuel Costs;

13. Virginia Case No. PUE990717 – Application of Virginia Electric and Power Company to Revise Its Fuel Factor Pursuant to Virginia Code Section 56-249.6;

14. Texas Docket No. 22344 – Generic Issues Associated with Applications for Approval of Unbundled Cost of Service Rates Pursuant to PURA Section 39.201 and Public Utility Commission Substantive Rule § 25.344;

15. Texas Docket No. 22350 – Application of TXU Electric Company for Approval of Unbundled Cost of Service Rates Pursuant to PURA Section 39.201 and Public Utility Commission Substantive Rule 25.344 (Phase III);

16. Texas Docket No. 22352 – Application of Central Power and Light Company for Approval of Unbundled Cost of Service Rates Pursuant to PURA Section 39.201 and Public Utility Commission Substantive Rule 25.344 (Final Phase);

17. Texas Docket No. 22353 – Application of Southwestern Electric Power Company for Approval of Unbundled Cost of Service Rates Pursuant to PURA Section 39.201 and Public Utility Commission Substantive Rule 25.344 (Final Phase);

18. Texas Docket No. 22354 – Application of West Texas Utilities Company for Approval of Unbundled Cost of Service Rates Pursuant to PURA Section 39.201 and Public Utility Commission Substantive Rule 25.344 (Final Phase);

19. Texas Docket No. 22356 – Application of Entergy Gulf States, Inc. for Approval of Unbundled Cost of Service Rates Pursuant to PURA Section 39.201 and Public Utility Commission Substantive Rule 25.344;

20. Texas Docket No. 22349 – Application of Texas-New Mexico Power Company for Approval of Unbundled Cost of Service Rates Pursuant to PURA Section 39.201 and Public Utility Commission Substantive Rule 25.344 (Final Phase);

21. Virginia Case No. PUE000584 – Application of Virginia Electric and Power Company for Approval of a Functional Separation Plan under the Virginia Electric Utility Restructuring Act;

22. Texas Docket No. 24468 – Staff's Petition to Determine Readiness for Retail Competition in the Portions of Texas Within the Southwest Power Pool;

23. Texas Docket No. 24469 – Staff's Petition to Determine Readiness for Retail Competition in the Portions of Texas Within the Southeastern Electric Reliability Council;

24. Virginia Case No. PUE-2002-00377 – Application of Virginia Electric and Power Company to Revise Its Fuel Factor Pursuant to Section 56-249.6 of the Code of Virginia;

25. Texas Docket No. 27035 – Application of Central Power and Light Company for Authority to Reconcile Fuel Costs;

26. Texas Docket No. 28818 – Application of Entergy Gulf States, Inc. for Certification of an Independent Organization for the Entergy Settlement Area in Texas;

27. Virginia Case No. PUE-2000-00550 -- Appalachian Power Company d/b/a American Electric Power: Regional Transmission Entities;

28. Texas Docket No. 29408 – Application of Entergy Gulf States, Inc. for the Authority to Reconcile Fuel Costs;

29. Texas Docket No. 29801 – Application of Southwestern Public Service Company for: (1) Reconciliation of its Fuel Costs for 2002 and 2003; (2) A Finding of Special Circumstances; and (3) Related Relief;

30. Texas Docket No. 30143 -- Petition of El Paso Electric Company to Reconcile Fuel Costs;

31. Texas Docket No. 31540 – Proceeding to Consider Protocols to Implement a Nodal Market in the Electric Reliability Council of Texas Pursuant to PUC Substantive Rule 25.501;

32. Texas Docket No. 32795 – Staff's Petition to Initiate a Generic Proceeding to Re-Allocate Stranded Costs Pursuant to PURA Section 39.253(f);

33. Texas Docket No. 33309 – Application of AEP Texas Central Company for Authority to Change Rates;

34. Texas Docket No. 33310 – Application of AEP Texas North Company for Authority to Change Rates;

35. Michigan Case No. U-15245 – In the Matter of the Application of Consumers Energy Company for Authority to Increase its Rates for the Generation and Distribution of Electricity and for Other Rate Relief;

36. Texas Docket No. 34800 – Application of Entergy Gulf States, Inc. for Authority to Change Rates and to Reconcile Fuel Costs;

37. Texas Docket No. 35717 – Application of Oncor Electric Delivery Company LLC for Authority to Change Rates; and

38. RIPUC Docket No. 4065 – Application of the Narragansett Electric Company d/b/a National Grid for Approval of a Change in Electric Base Distribution Rates Pursuant to R.I.G.L. Sections 39-3-10 and 39-3-11.

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Narragansett Electric Company

Summary of Customer Service Retail Market Expense and Total Account 910 - Customer Service - Miscellaneous Expenses

		Customer Service Retail Market Expense				Total Account 910 Expenses				Account 910 Allocator	
		Company	Modified	Change		Company	Modified	Change		Company	Modified
Line	Customer Class	Proposed	CCOSS	Amount	Percent	Proposed	CCOSS	Amount	Percent	Proposed	CCOSS
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Residential	$ 44,551	$ 96,556	$ 52,005	116.7%	$ 715,956	$ 767,962	$ 52,005	7.3%	80.337%	86.173%
2	Small C&I	$ 8,533	$ 11,326	$ 2,793	32.7%	$ 87,287	$ 90,080	$ 2,793	3.2%	9.794%	10.108%
3	General C&I	$ 18,513	$ 1,875	$ (16,639)	-89.9%	$ 31,550	$ 14,912	$ (16,639)	-52.7%	3.540%	1.673%
4	200 kW Demand	$ 31,696	$ 236	$ (31,459)	-99.3%	$ 33,338	$ 1,879	$ (31,459)	-94.4%	3.741%	0.211%
5	3000 kW Demand	$ 7,494	$ 3	$ (7,491)	-100.0%	$ 7,516	$ 25	$ (7,491)	-99.7%	0.843%	0.003%
6	Lighting	$ 936	$ 2,053	$ 1,117	119.3%	$ 15,212	$ 16,329	$ 1,117	7.3%	1.707%	1.832%
7	Propulsion	$ 326	$ 0	$ (326)	-99.9%	$ 328	$ 2	$ (326)	-99.5%	0.037%	0.000%
8	**Total**	**$ 112,050**	**$ 112,050**	**$ 0**	**0.0%**	**$ 891,188**	**$ 891,188**	**$ 0**	**0.0%**	**100.000%**	**100.000%**

Source:
R.I.P.U.C. Docket No. 4323, Sponsor-H.S. Gorman, Schedule NG-HSG-3M.

Narragansett Electric Company

Summary of Cost of Service Study Results
Rate Year Ended January 31, 2014

		Present Rates[1]			Company Proposed Revenue Distribution[1,2]			Revenue Distribution Under Modified CCOSS Results[3]		
Line	**Customer Class**	**Rate of Return**	**Relative Rate of Return**	**Over/(Under) Collection (000)**	**Rate of Return**	**Relative Rate of Return**	**Over/(Under) Collection (000)**	**Rate of Return**	**Relative Rate of Return**	**Over/(Under) Collection (000)**
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Residential	3.37%	78	$ (4,605)	7.81%	99	$ (192)	7.82%	100	$ (145)
2	Small C&I	7.10%	163	$ 2,402	9.43%	120	$ 1,373	9.43%	120	$ 1,376
3	General C&I	9.14%	210	$ 6,316	9.44%	120	$ 2,096	9.43%	120	$ 2,076
4	200 kW Demand	7.09%	163	$ 3,398	9.41%	120	$ 1,933	9.38%	120	$ 1,900
5	3000 kW Demand	-5.07%	-117	$ (2,937)	0.47%	6	$ (2,301)	0.47%	6	$ (2,302)
6	Lighting	-5.04%	-116	$ (4,394)	1.92%	24	$ (2,778)	1.92%	24	$ (2,777)
7	Propulsion	-2.04%	-47	$ (180)	3.22%	41	$ (130)	3.21%	41	$ (131)
8	**Total**	**4.35%**	**100**	**$ -**	**7.85%**	**100**	**$ -**	**7.85%**	**100**	$ -

Sources:

[1] Company results based on response to Division 21-4(d)-ELEC (Supplemental).

[2] Assumes the rate increase for the 3,000 kW Rate B/G-62, Lighting and Propulsion classes is capped at 2 times the system average.

[3] Due to lack of adequate data, I have not quantified the impact of my recommendation to cap the increase for customers with demands greater than 8 MW at 150% of the system average increase. Therefore, the revenue distribution shown here is based on the Company's proposal.

Narragansett Electric Company

Summary of Base Rate Increase
Rate Year Ended January 31, 2014

Line	Customer Class	Present Revenues (000)	Company CCOSS Rate Change[1] Amount (000)	Company CCOSS Rate Change[1] Percent	Company Proposed Revenue Distribution[1,2] Amount (000)	Company Proposed Revenue Distribution[1,2] Percent	Modified CCOSS Rate Change Amount (000)	Modified CCOSS Rate Change Percent	Modified CCOSS Revenue Distribution[3] Amount (000)	Modified CCOSS Revenue Distribution[3] Percent
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Residential	$ 123,070	$ 20,338	16.5%	$ 20,243	16.4%	$ 22,736	18.5%	$ 22,510	18.3%
2	Small C&I	$ 25,514	$ 1,105	4.3%	$ 2,328	9.1%	$ 1,194	4.7%	$ 2,375	9.3%
3	General C&I	$ 38,676	$ (525)	-1.4%	$ 1,242	3.2%	$ (862)	-2.2%	$ 823	2.1%
4	200 kW Demand	$ 35,317	$ 1,572	4.5%	$ 3,310	9.4%	$ (176)	-0.5%	$ 1,415	4.0%
5	3000 kW Demand	$ 5,527	$ 3,494	63.2%	$ 1,454	26.3%	$ 3,060	55.4%	$ 1,454	26.3%
6	Lighting	$ 10,426	$ 5,220	50.1%	$ 2,743	26.3%	$ 5,272	50.6%	$ 2,743	26.3%
7	Propulsion	$ 494	$ 245	49.6%	$ 130	26.3%	$ 226	45.8%	$ 130	26.3%
8	**Total**	**$ 239,023**	**$ 31,450**	**13.2%**	**$ 31,450**	**13.2%**	**$ 31,450**	**13.2%**	**$ 31,450**	**13.2%**

Source:
[1] Company results based on response to Division 21-4(d)-ELEC (Supplemental).
[2] Assumes the rate increase for the 3,000 kW Rate B/G-62, Lighting and Propulsion classes is capped at 2 times the system average.
[3] Due to lack of adequate data, I have not quantified the impact of my recommendation to cap the increase for customers with demands greater than 8 MW at 150% of the system average increase. Therefore, the revenue distribution shown here is based on the Company's proposal.