nationalgrid

Raquel J. Webster
Senior Counsel

August 1, 2014

BY HAND DELIVERY AND ELECTRONIC MAIL

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

RE: Docket 4382 - Fiscal Year 2014 Electric Infrastructure, Safety, and Reliability Plan Fourth Quarter Report, Annual Report, and Reconciliation Filing

Dear Ms. Massaro:

On behalf of National Grid,[1] relating to the Company's Fiscal Year ("FY") 2014 Electric Infrastructure, Safety, and Reliability ("ISR") Plan, I have enclosed ten copies of the Company's Fourth Quarter Report, Annual Report, and Reconciliation filing. Pursuant to the approved ISR Plan and the Infrastructure, Safety, and Reliability Provision, R.I.P.U.C. No. 2188, after the end of the ISR Plan year, which runs from April 1 through March 31, the Company must file annually, by August 1 of each year, the proposed CapEx Reconciling Factors and O&M Reconciling Factor that will become effective for the twelve months beginning October 1. The CapEx Reconciling Factors recover or credit the difference between the reconciliation of actual billed revenue generated from the CapEx Factors and the actual Cumulative Revenue Requirement for the applicable plan year. Similarly, the annual O&M Reconciling Factor recovers or credits the difference between the reconciliation of actual billed revenue from the O&M Factor and actual Inspection and Maintenance ("I&M") program expense and actual Vegetation Management ("VM") program expense for the ISR Plan year. Additionally, on August 1, the Company must submit an annual report on the prior fiscal year's ISR Plan activities and include descriptions of deviations from the original plans approved by the Rhode Island Public Utilities Commission ("PUC").

This filing provides the actual plant-in-service for discretionary and non-discretionary capital investment and associated cost of removal and actual VM and I&M expenses for the period April 1, 2013 to March 31, 2014. As explained in this filing, the actual plant-in-service investment is compared to the budgeted amounts for these categories as approved by the PUC in the FY 2014 Electric ISR Plan. The plant-in-service investment and the O&M expenses are then used in the calculation of the revenue requirement for the annual reconciliation of investment and expenses for the fiscal year. This revenue requirement is then compared to actual revenue billed, and any difference forms the basis for the proposed Electric ISR Plan reconciliation factors for effect October 1, 2014. This filing also includes details on the Company's actual discretionary and non-

[1] The Narragansett Electric Company d/b/a National Grid (hereinafter referred to as "National Grid" or the "Company").

discretionary capital investment spending by category during FY 2014. Finally, this filing includes a summary of the Company's Reliability Performance through December 31, 2013.

The pre-filed direct testimonies of Jennifer Grimsley, William R. Richer, and Scott M. McCabe are enclosed with this filing. Ms. Grimsley presents the Company's FY 2014 Fourth Quarter Electric ISR Plan Report, the FY 2014 Annual Report, and the FY 2014 Annual Reconciliation filing related to the FY 2014 Electric ISR Plan approved by the PUC in this docket. Mr. Richer's testimony describes the calculation of the revenue requirement based on the actual capital plant-in-service and the total actual VM and I&M expenses for the fiscal year. His testimony also includes a description of the revenue requirement model and attachments that support the final revenue requirement. As explained in Mr. Richer's testimony, for the FY 2014 filing, the Company has an updated revenue requirement of approximately $11 million. Mr. McCabe's testimony includes a description of the reconciliation of the final actual FY 2014 revenue requirement against revenue billed in support of that revenue requirement, the proposed factors resulting from the reconciliation, and the bill impacts of those proposed factors. The impact of the proposed CapEx Reconciling Factor and the proposed O&M Reconciling Factor on a typical residential customer receiving Standard Offer Service and using 500 kWhs per month is a decrease of $0.04, or approximately 0.0%, from $86.65 to $86.61.

Thank you for your attention to this transmittal. If you have any questions, please contact me at (781) 907-2121.

Very truly yours,

Raquel J. Webster

Enclosures

cc: Docket 4382 Service List
LeoWold, Esq.
Steve Scialabba, Division
James Lanni, Division
Al Contente, Division

National Grid

The Narragansett Electric Company

FY 2014 Electric Infrastructure, Safety, and Reliability Plan

Fourth Quarter Report, Annual Report, and Annual Reconciliation

August 1, 2014

Docket No. 4382

Submitted to:
Rhode Island Public Utilities Commission

Submitted by:

nationalgrid

Testimony of
Jennifer L. Grimsley

PRE-FILED DIRECT TESTIMONY

OF

JENNIFER L. GRIMSLEY

August 1, 2014

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Jennifer L. Grimsley. My business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

Q. By whom are you employed and in what capacity?

A. I am employed by National Grid USA Service Company, Inc. (“Service Company”) as Director, Network Strategy, New England Electric. I am responsible for regulatory filings and regulatory compliance related to the electric distribution operations of The Narragansett Electric Company d/b/a National Grid (the “Company”). I am also responsible for similar filings relating to National Grid’s electric distribution operations in Massachusetts.

Q. Please describe your educational background and professional experience.

A. In 1986, I graduated from Washington University with a bachelor’s degree in electrical engineering. In 1991, I graduated from Rivier College with a master’s degree in business administration. In 1986, I began my engineering career as an associate engineer with Massachusetts Electric Company (“Mass. Electric”) in North Andover. In 1993, I was promoted to district engineering manager for Mass. Electric in Northampton, and have held various engineering and management positions since that time, including Project Manager for the Reliability Enhancement Program in 2006. In 2007, I became Manager of

Asset Strategy and Policy and was responsible for developing the strategies to replace distribution assets. In 2008, I was promoted to Director, Asset Strategy and Policy. In 2009, I became Executive Advisor to the Chief Operating Officer of Electricity Operations for National Grid. In 2011, I assumed my current role as Director, Network Strategy, New England Electric.

Q. Have you previously testified before the Rhode Island Public Utilities Commission ("PUC")?

A. Yes. I have testified in support of the previous Electric Infrastructure, Safety and Reliability ("ISR") Plan filings in Docket Nos. 4218, 4307, 4382, and 4473. I also testified in the Contact Voltage Proceeding in Docket No. 4237.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to present the Company's Fiscal Year ("FY") 2014 Fourth Quarter Electric ISR Plan Report, the FY 2014 Annual Report, and the FY 2014 Annual Reconciliation filing related to the FY 2014 Electric ISR Plan approved by the PUC in this docket. This filing provides the actual plant-in-service for discretionary and non-discretionary capital investment and associated cost of removal ("COR")[1], the actual Vegetation Management ("VM") expenses, and the actual Inspection and Maintenance ("I&M") expenses for the period April 1, 2013 to March 31, 2014. As described in his testimony in this filing, Mr. William Richer uses this plant-in-service investment and the Operation and Maintenance ("O&M") expenses for VM and I&M to calculate the FY 2014 Electric ISR Plan revenue requirement. As explained in Mr. Scott M. McCabe's testimony in this filing, this revenue requirement is then reconciled against actual revenue billed during FY 2014. The specific FY 2014 Electric ISR Plan plant-in-service additions and COR by categories, as well as actual spending, are included in Attachment JLG-1 attached to this testimony.

III. PLANT-IN-SERVICE OVERVIEW

Q. Please provide an overview of the plant-in-service for FY 2014.

A. As shown on Table 1 in Attachment JLG-1, the Company placed $56.1 million of plant-in-service. This amount is $2.7 million more than the forecasted amount of approximately $53.4 million for plant-in-service for FY 2014. This amount of $2.7 million is primarily driven by a variance of $4.5 million above the forecasted amount in the non-discretionary category. This $4.5 million is offset by a variance of $1.7 million

[1] Under the Electric ISR Plan, discretionary capital investment for a fiscal year must be reconciled to the lesser of the actual capital investment placed-in-service and the level of approved spending on a cumulative basis. Non-discretionary capital investment for a fiscal year must be reconciled to the actual capital investment placed-in-service. Docket No. 4218, Report and Order No. 20852 at 6 (December 12, 2011).

below the forecasted amount in the discretionary category. Details on these variances are included in Section I of Attachment JLG-1.

As explained in Mr. Richer's testimony, the plant-in-service amounts and the COR provided in Table 2 in Attachment JLG-1 are used to calculate the revenue requirement included in the ISR Plan reconciliation for FY 2014. These amounts are reflected in the Electric ISR Plan reconciliation factors. The capital spending amounts are not used in this calculation.

IV. ACTUAL CAPITAL SPENDING

Q. Please summarize the Company's actual capital spending for FY 2014 for the Electric ISR Plan.

A. As set forth in Table 3 in Attachment JLG-1, for FY 2014, the Company spent $78.0 million for capital investment under the Electric ISR Plan. This amount was $18.4 million above budget against an annual approved budget of $59.6 million. The $18.4 million variance included approximately $5.0 million in the non-discretionary capital category. This was primarily driven by a $4.3 million variance above budget in the Damage/Failure category, which was primarily due to increased costs in the overhead line blanket and additional costs from major storms from prior years. In addition, there was an additional $0.6 million variance above budget for certain public requirements related to the I-195 project and new business (commercial and residential) in the Customer Request/Public Requirements[2] category.

A $13.4 million spending variance above budget for the System Capacity and Performance category also contributed to the $18.4 variance above budget in the discretionary capital category (Asset Condition, Non-Infrastructure and System Capacity and Performance). This variance was driven primarily by the increased cost and completion of a significant number of projects for Load Relief. This included a $5.7 million variance above budget for the Highland Drive project, which was initially incorrectly budgeted as Transmission work instead of Distribution work, and a $1.9 million over-budget variance for the Johnston #18 Substation due to the acceleration and completion of this work ahead of schedule. As discussed in more detail in Attachment JLG-1, the remaining variance of $5.8 million is attributable to either variances on smaller individual projects or work on individual projects, which have progressed as budgeted and have not required full use of the negative schedule reserve included in the FY 2014 budget. The Company uses negative schedule reserves with the goal of eliminating churn when projects do not proceed as scheduled due to delays from things such as permitting, obtaining easements, telephone pole sets, or other issues that were unknown when the budget was finalized. While spending on System Capacity and

[2] In the Company's prior Electric ISR Plan filings with the PUC, the Customer Request/Public Requirement category was previously referred to as the Statutory/Regulatory category.

Performance was significantly above budget, the majority of this was on multi-year projects with in service dates over the next several years and, therefore, had no impact on the plant-in-service for FY 2014.

V. O&M SPENDING

Q. Please summarize the Company's actual O&M spending for the FY 2014 Electric ISR Plan.

A. As shown on Table 10 in Attachment JLG-1, the total VM spending for FY 2014 was $8.53 million compared to an approved budget of $8.48 million. In addition, as shown on Table 11, the overall I&M spending was approximately $3.6 million compared to an approved budget of $3.8 million. Detailed information regarding the VM and I&M variances and the work completed is discussed in Sections III and IV of Attachment JLG-1.

VI. RELIABILITY

Q. Please summarize the results of the Company's reliability performance for FY 2014.

A. Table 12 in Attachment JLG-1 presents the Company's Reliability Performance for calendar year 2013 ("CY 2013"). As shown in Table 12, the Company met both its SAIFI and SAIDI performance metrics in CY 2013, with SAIFI of 0.72, against a target of 1.05, and SAIDI of 57.28 minutes, against a target of 71.9 minutes. Overall, the Company's performance has shown a downward (improving) trend over the past several years with major event days excluded. For CY 2013, the Company had three days from two separate events that were characterized as major event days. The most significant single event was the Nor'easter on February 8, 2013. As a result of this storm, approximately 238,000 customers were interrupted with all customers restored by February 13, 2013. Only the first two days of the storm exceeded the major event day threshold of 5.74 minutes. All events in 2013 characterized as major event days are shown in Table 13. Table 14 provides the overall reliability performance measures including major event days.

Q. Does this conclude this testimony?

A. Yes, it does.

Attachment JLG-1

Attachment JLG-1

FY 2014 Electric ISR Plan Annual Report and Annual Reconciliation Summary

Electric Infrastructure, Safety, and Reliability Plan FY 2014 Fourth Quarter Report, Annual Report, and Annual Reconciliation Filing

Executive Summary

In accordance with tariff, R.I.P.U.C. No. 2044, Sheets 1-4, The Narragansett Electric Company d/b/a/ National Grid (the "Company") submits this fourth quarter report, annual report, and annual reconciliation filing for the fiscal year 2014 ("FY 2014") Electric Infrastructure, Safety, and Reliability ("ISR") Plan approved by the Rhode Island Public Utilities Commission ("PUC") in Docket No. 4382. This filing provides the actual plant-in-service for discretionary and non-discretionary capital investment and associated cost of removal ("COR")[1], the actual Vegetation Management ("VM") expenses, and the actual Inspection and Maintenance ("I&M") expenses for the period April 1, 2013 to March 31, 2014. As explained in this filing, the actual capital plant-in-service investment is compared to the budgeted amounts for these categories as approved by the PUC in the FY 2014 Electric ISR Plan. The plant-in-service investment and the Operation and Maintenance ("O&M") expenses for VM and I&M are then used in the calculation of the revenue requirement for the annual reconciliation of investment and expenses for the fiscal year. This revenue requirement is then compared to actual revenue billed, and any difference forms the basis for the proposed Electric ISR Plan reconciliation factors for effect October 1, 2014. This filing also includes details on the Company's actual discretionary and non-discretionary capital investment spending by category during FY 2014. Finally, this filing includes a summary of the Company's Reliability Performance through December 31, 2013.

As identified in the Company's FY 2013 Annual Reconciliation filing, National Grid implemented a consolidated back office system (SAP) in November 2012. The major conversion resulted in significant implementation issues that continued to persist during FY 2014. As a result, the Company has delayed the filing of its FY 2014 Fourth Quarter Electric ISR Report to coincide with the filing of its annual Electric ISR reconciliation filing to perform additional review of the financial information typically included in this report. The spending results for the FY 2014 Electric ISR plan have now been reviewed and several adjustments were made based on a review of capital, expense, and cost of removal cost trends. As the Company previously stated, if the Company should discover any additional adjustments of the data recorded in its

[1] Under the Electric ISR Plan, discretionary capital investment to be used in this reconciliation shall be the lesser of the actual capital investment placed-in-service or the level of approved spending on a cumulative basis. Non-discretionary capital investment for this reconciliation shall reflect actual capital investment placed-in-service. Docket No. 4218 at 6. *Order 20582 (2011)*

general ledger and submitted with this filing, appropriate adjustments to this filing will be submitted to ensure that customers are insulated from any unintended economic harm.

For FY 2014, the Company's Electric ISR Plan plant-in-service investment was $56.1 million, which was $2.8 million greater than the forecasted plant-in-service of $53.4 million. However, the $5.0 million cost of removal was $4.5 million less than the Company's forecast of $9.6 million. These totals resulted in a net Electric ISR investment that was $1.8 million less than the Company's forecast. Section I below provides a summary of the actual plant placed in service in FY 2014 compared to the FY 2014 Electric ISR Plan budget approved in Docket No. 4382. This summary separates non-discretionary and discretionary capital investments. Section I also includes a similar summary for COR. Section II provides a summary of the actual capital spending-by-category and a detailed explanation of capital investment variances by each category to the budget. Section III provides a breakdown of VM expenses of $8.5 million and an explanation of the variance for these expenses within the categories of the approved budget of $8.5 million. Section IV provides a similar breakdown for the $3.6 million of I&M expenses and an explanation of the variance with the approved budget of $3.8 million. Sections I - IV also serve as the Company's FY 2014 Fourth Quarter Electric ISR Plan Report and the FY 2014 Annual Report to the PUC for the fiscal year.[2] The Company's reliability performance metrics are addressed in Section V.

The testimony of Mr. William R. Richer, which accompanies this filing, describes the calculation of the revenue requirement based on the capital plant-in-service and the total annual actual VM and I&M expenses for the fiscal year. His testimony also includes a description of the revenue requirement model and attachments that support the final revenue requirement. As shown in Mr. Richer's testimony, for the FY 2014 filing, the Company has an updated revenue requirement of $10,981,596 .

The testimony of Mr. Scott M. McCabe, which accompanies this filing, provides a description of the reconciliation of the final actual FY 2014 revenue requirement against revenue billed in support of that revenue requirement, the proposed factors resulting from the reconciliation, and the bill impacts of those proposed factors. The impact of the proposed CapEx Reconciling Factor and the proposed O&M Reconciling Factor on a typical residential customer receiving Standard Offer Service and using 500 kWhs per month is a decrease of $0.05, or approximately 0.1%, from $86.65 to $86.60.

Finally, as noted above, although it does not directly impact the reconciliation of the revenue requirement and billed ISR Plan revenue in this filing, the actual capital spending provided in Section II serves as the Company's FY 2014 Fourth Quarter Electric ISR Plan

[2] FY 2014 Electric ISR Fourth Quarter and Annual Plant-in-Service Investment, COR, and VM and I&M expenses are provided in Tables 1, 2, 10, and 11.

Report and FY 2014 Annual Report. For FY 2014, the Company's actual capital Electric ISR Plan spending was $78.0 million, which was $18.4 million more than the annual approved budget of $59.6 million. FY 2014 is the third year of the ISR Plan and the first year in which the Company spent more than the approved capital budget. FY 2012 capital spending was $7.9 million below budget, and FY 2013 capital spending was $7.0 million below budget.

Note that the revenue requirement and billed ISR Plan revenue in this filing is based on plant in service and not capital spending. The key drivers for the FY 2014 capital spending variance include:

- A project was initially incorrectly budgeted as Transmission work when it should have been budgeted as Distribution work;
- The Company accelerated the schedule on several projects, as discussed further in Section II;
- Work on the majority of the individual projects progressed as budgeted and did not require full use of the negative schedule reserve included in the fiscal year budget; and
- Higher than historical trends in the Damage/Failure category driven by prior year major storms and increased labor related charges to distribution line blanket projects.

I. FY 2014 Capital for Plant Investment Placed in Service

As shown in Table 1 below, for FY 2014, $56.1 million of capital investment was placed in service, which was $2.8 million above the forecast for plant-in-service for the fiscal year. Table 2 provides the total Cost of Removal ("COR") for FY 2014, which was $5.0 million or $4.5 million below the forecast for the fiscal year.

Table 1 [3]

	FY 2014 Annual ISR Forecast	FY 2014 Actual in Service	Variance
NON-DISCRETIONARY CAPITAL INVESTMENT			
Customer Request/Public Requirement	$16,319,000	$13,844,844	($2,474,156)
Damage/Failure	$9,977,000	$16,928,183	$6,951,183
Subtotal	**$26,296,000**	**$30,773,027**	**$4,477,027**
DISCRETIONARY CAPITAL INVESTMENT			
Asset Condition	$17,954,000	$14,639,889	($3,314,111)
Non-Infrastructure	$257,000	$1,989,798	$1,732,798
System Capacity & Peformance	$8,866,000	$8,726,837	($139,163)
Subtotal	**$27,077,000**	**$25,356,524**	**($1,720,476)**
Total Capital Investment in Systems	**$53,373,000**	**$56,129,551**	**$2,756,551**

[3] For consistency, in this Attachment, "Variances", which are shown in parentheses ( ), reflect an under spending.

The specific category variances in Table 1 reflect the timing of when plant investment is placed into service. In general, once equipment is energized and placed into service to support electric load, capital costs are transferred from FERC Account 107 (Construction Work in Progress or "CWIP") to FERC Account 106 ("Plant-In-Service") at the time that the underlying capital work becomes used and useful in the service of customers. This can differ by the type of plant and facility. For example, electric distribution line equipment is normally placed in service closer to the time it is installed because it is typically energized at that time and begins to support electric load, and therefore, is used and useful in the service of customers. Because electric distribution line equipment is typically energized as it is installed, a relatively significant amount of plant is placed into service as work progresses. By contrast, substation construction typically involves multi-year projects. Therefore, the assets must pass testing, the work must be commissioned, and the assets must be energized before they can be placed in service. Because substation construction is typically completed in one or more phases as part of a multi-year process, these assets will only be placed in service to serve customers once all work in a particular phase is completed.

Additions to plant-in service for the Customer Request/Public Requirements[4] and Asset Condition are both less than the forecasted levels for FY 2014. During FY 2013, the Company's spending in these categories was below forecast, and this under spending in FY 2013 had the effect of a lower level of plant additions when assets in these categories were ultimately placed in service in FY 2014. The variance above budget for Damage/Failure plant-in-service is driven by higher than anticipated costs associated with major storms during FY 2014 as well as spending during FY 2013 that was ultimately placed in service in FY 2014. The variance above budget for the Non-Infrastructure plant-in-service is driven by costs incurred during FY 2013 for the radio improvement project, which was placed in service in FY 2014. The Company expected that this project would be in service in FY 2013 and, therefore, it was not accounted for in the FY 2014 plant-in-service forecast. The variance above forecast for the Non-Infrastructure plant in service was offset by the variance below forecast in the Asset Condition category, resulting in the total for the Discretionary plant-in-service investment to be below forecast. The System Capacity and Performance category was essentially on budget for plant-in-service. While spending on System Capacity and Performance was significantly above budget, as described in Section II, the majority of this variance was on multi-year projects with in-service dates over the next several years and, therefore, had no impact on the plant-in-service for FY 2014.

[4] The Customer Request/Public Requirement category was previously referred to as the Statutory/Regulatory category in prior Electric ISR Filings.

Table 2

	FY14 Annual ISR COR Forecast	FY14 Actual COR	Variance
NON-DISCRETIONARY COST OF REMOVAL			
Customer Request/Public Requirement	$2,219,000	$1,074,484	($1,144,516)
Damage/Failure	$1,658,000	$2,249,507	$591,507
Subtotal	**$3,877,000**	**$3,323,991**	**($553,009)**
DISCRETIONARY COST OF REMOVAL			
Asset Condition	$4,606,000	$1,734,420	($2,871,580)
Non-Infrastructure	$0	$0	$0
System Capacity & Peformance	$1,062,000	($50,419)	($1,112,419)
Subtotal	**$5,668,000**	**$1,684,001**	**($3,983,999)**
Total Cost of Removal	**$9,545,000**	**$5,007,992**	**($4,537,008)**

The overall variance below forecast for COR was impacted by process issues related to the implementation of the new SAP system. A number of complexities with charging time in the new system resulted in a lower percentage of time being charged to COR and a higher percentage of time being charged to expense and capital. For example, prior to SAP, COR was predetermined in the Company's legacy accounting system as a percentage of the time spent depending on the type of work that was being performed. Initially, the SAP system required construction crews to charge multiple lines of accounting for work that was previously charged to a single line of accounting, and employees were required to specify the amount of time spent on COR separate from the amount of time installing the replacement asset. In many instances, employees continued to charge the single-line of accounting, resulting in an under-statement in the amount of COR for FY 2014, but an over-statement of amounts charged to expense and capital. System and process changes have been made in SAP in July 2014 to simplify this situation going forward. An accounting adjustment has been made in the Damage/Failure category to reflect the appropriate COR for this category. The actual COR for Damage/Failure is above forecast due to the total capital spending in Damage/Failure being above forecast, as discussed in Section II. Additional adjustments for FY 2014 will be processed in FY 2015 to fully correct for this issue.

II. FY 2014 Capital Spending Results

1. Capital Spending Overview

Table 3 below provides the Company's FY 2014 Fourth Quarter Electric ISR Plan Report and FY 2014 Annual Report capital spending. Overall, for FY 2014, the Company spent $78.0 million for capital investment under the Electric ISR Plan. This amount was $18.4 million over budget against an annual approved budget of $59.6 million. The key drivers and variances by category of capital are as discussed in greater detail in Section 2 below.

Table 3

	FY14 Annual ISR Budget	FY14 Actual	Variance
NON-DISCRETIONARY CAPITAL SPENDING			
Customer Request/Public Requirement	$16,509,000	$17,137,642	$628,642
Damage/Failure	$10,050,000	$14,373,392	$4,323,392
Subtotal	**$26,559,000**	**$31,511,034**	$4,952,034
DISCRETIONARY CAPITAL SPENDING			
Asset Condition	$20,242,000	$20,904,838	$662,838
Non-Infrastructure	$255,000	($346,246)	($601,246)
System Capacity & Performance	$12,544,000	$25,972,338	$13,428,338
Subtotal	**$33,041,000**	**$46,530,930**	**$13,489,930**
TOTAL CAPITAL SPENDING	**$59,600,000**	**$78,041,964**	**$18,441,964**

2. Actual Spending by Category

a. Non-Discretionary Capital Expenditures Compared to FY 2014 Budget

The key drivers for the variances by major categories for non-discretionary capital spending compared to the budget for FY 2014 are listed below.

1. ***Customer Request/Public Requirement - $0.6 million over budget for FY 2014***

As shown in Table 4 below, the overall variance for the Customer Request/Public Requirement was slightly more than budget due primarily to higher than anticipated activity in new business, both commercial and residential, as well as increased spending on public requirements.

As shown below, the New Business – Commercial budget category had a variance above budget primarily driven by the Shun Pike project being delayed into FY 2014 from FY 2013. The New Business – Residential budget category had a variance above budget primarily driven by higher than anticipated activity on small projects (under $100,000 per project) in the blanket project for this category. The Public Requirements budget category had a variance above budget primarily driven by the timing and increased scope of the I-195 Contract 14 and 15 projects.

Several budget categories in the Customer Request/Public Requirement category also had variances below budget. The variance below budget for the Meters – Distribution budget category was driven by fewer meter purchases for required installations and a change in capital overhead allocations after the implementation of the new SAP system, where capital overheads are no longer applied to material charges. The variance below budget for the Transformers and related equipment budget category was driven by fewer purchases for required installation and the change in capital overhead allocations after the implementation of SAP.

Table 4

SPENDING RATIONALE	Budget Classification	FY 2014 Budget	FY 2014 Actual Spending	Variance
Customer Request/ Public Requirement	3rd Party Attachments	$514,000	$141,413	($372,587)
	Land and Land Rights - Dist	$190,000	$93,851	($96,149)
	Meters - Dist	$1,752,000	$834,910	($917,090)
	New Business - Commercial	$4,300,000	$4,956,626	$656,626
	New Business - Residential	$3,025,000	$3,592,833	$567,833
	Outdoor Lighting - Capital	$537,000	$758,113	$221,113
	Distributed Generation	$162,000	$195,033	$33,033
	Public Requirements	$2,599,000	$4,233,542	$1,634,542
	Transformers & Related Equipment	$3,430,000	$2,331,320	($1,098,680)
Customer Request/Public Requirement Sub-Total		**$16,509,000**	**$17,137,642**	**$628,642**

2. ***Damage/Failure - $4.3 million over-budget for FY 2014***

The detailed budget and actual spending by budget classification for FY 2014 for the Damage/Failure category is shown in Table 5 below. In the FY 2014 Electric ISR Plan Third Quarter report, the Company indicated that because of higher than historical trends driven by prior year major storms and increased labor-related charges to blanket projects, the Damage/Failure category was projected to be approximately $3.7 million over budget at the end of the fiscal year. These trends continued in the fourth quarter, and for FY 2014, the Damage/Failure category ended the fiscal year with a $4.3 million over budget variance.

The damage failure budget classification had a variance $1.8 million greater than budget due to increased costs in the damage failure overhead line blanket. These increased costs were driven by increased labor related charges to blanket projects. The Major Storms – Distribution budget classification had a total variance above budget of approximately $2.5 million. Activity from the prior year's "Nemo" storm in February 2013 was the primary driver for $1.1 million of this variance; increased storm activity in FY 2014, including the July 2013 heat wave and several wind and snow events during the fall and winter months, accounts for the rest. Capital replacement work during major storm events is not recovered through the storm fund. However, in the process of reviewing costs to be recovered through the storm fund, the Company will review all costs to ensure that capital and expense costs are captured correctly. The Company is currently reviewing all storm costs for storms in calendar years 2012 and 2013 and will make any necessary adjustments to capital before it files for recovery in the storm fund.

Table 5

SPENDING RATIONALE	Budget Classification	FY2014 Budget	FY 2014 Actual Spending	Variance
Damage/Failure	Damage/Failure	$9,375,000	$11,227,718	$1,852,718
	Major Storms-Dist	$675,000	$3,145,674	$2,470,674
	Damage/Failure Sub-Total	**$10,050,000**	**$14,373,392**	**$4,323,392**

b. Discretionary Capital Expenditures Compared to Budget for FY 2014

1. *Asset Condition - $0.6 million over budget for FY 2014*

Overall spending in the Asset Condition category for FY 2014 was close to budget because this category had a variance above budget of $0.6 million at the end of the fiscal year. This variance was primarily driven by increased spending in overall asset replacement, which was partially offset by a variance below budget on the I&M program. The following projects are the primary drivers for the variance above budget in the asset replacement projects:

- The Breaker and Recloser Replacement project had a variance of approximately $890,000 over budget due to carryover from FY 2013, which was caused by engineering and material delays and outage constraints. This variance reflects increased installation costs from the initial project budget.

- The Asset Replacement Blanket project was $855,000 over budget due to an increased volume of identified and completed work as compared to prior years.

- As noted in the Company's FY 2014 Third Quarter Electric ISR Plan Report, a project to replace switchgear in downtown Providence, which was emergent work in FY 2013, was over-budget by $580,000 at the end of the fiscal year because this work was delayed into FY 2014 due to difficulty with scheduling the required outages with the customers involved.

- The Eldred Substation asset replacement was over budget by $264,000 due to material timing issues because transformer payments were made in March 2014.

Offsetting a portion of the variance above budget from the projects described above was the I&M program, which was below budget. As discussed in the Company's prior quarterly reports, the spending variance is primarily due to a delay in the full implementation of the program, which was driven by system changes made to the Company's work management system to appropriately capture grounding as a capital item. The third quarter forecast was lower than the final year-end costs because of an under-estimation of costs for engineering, design, and construction work that was invoiced and accrued in the fourth quarter. The third quarter forecast was also lower because of a vendor who was not submitting invoices in a timely fashion. This issue has since been resolved. Detailed budget and actual spending by budget classification for the Asset Condition category is shown in Table 6.

Table 6

SPENDING RATIONALE	Budget Classification	FY 2014 Budget	FY 2014 Actual Spending	Variance
Asset Condition	Asset Replacement	$11,377,000	$14,010,657	$2,633,657
	Asset Replacement - I&M	$8,515,000	$6,681,461	($1,833,539)
	Safety	$350,000	$212,720	($137,280)
	Asset Condition Sub-Total	**$20,242,000**	**$20,904,838**	**$662,838**

2. *__Non-Infrastructure - $0.6 million under budget for FY 2014__*

As shown in Table 7 below, overall spending in the non-infrastructure category for FY 2014 is lower than budget due to accounting adjustments that were made in the Administrative/General category. As discussed in Section I, accounting adjustments have been required to ensure correct capital, expense, and cost of removal charging due to complexities in charging time in the new system. The General Equipment category had a variance above budget due to an increased need for substation test equipment. The Telecommunications category had a variance above budget due to a radio improvement project, which carried over from FY 2013, as discussed in previous quarterly reports. This radio improvement project is now complete and placed in service.

Table 7

SPENDING RATIONALE	BUDGET CLASSIFICATION	FY2014 Budget	FY 14 Actual Spending	Variance
Non-Infrastructure	Administrative/General	$0	($1,244,746)	($1,244,746)
	General Equipment	$105,000	$394,675	$289,675
	Telecommunications	$150,000	$503,825	$353,825
	Non-Infrastructure Subtotal	**$255,000**	**($346,246)**	**($601,246)**

3. ***System Capacity and Performance - $13.4 million over budget for FY 2014***

Overall, spending was $13.4 million higher than budget in the System Capacity and Performance category for FY 2014. This was primarily driven by the Load Relief budget classification and the specific projects listed below. Detailed budget and actual spending by budget classification for the System Capacity and Performance category is shown in Table 8. Below are a few additional points regarding the System Capacity and Performance category:

- As noted in the Company's FY 2014 Third Quarter Electric ISR Plan Report, a significant portion of the Highland Drive project was initially incorrectly budgeted as Transmission work, when it should have been budgeted as Distribution work. The actual charges for this project are being reassigned to Distribution. This adjustment and completing more work than originally forecasted resulted in a $5.7 million over budget spending variance for the fiscal year.

- The Johnston #18 Substation had a variance $1.9 million above budget due to acceleration of this project ahead of schedule for both labor and material acquisition.

- The Kilvert St. distribution line work had a variance of $750,000 above budget at the end of the fiscal year. Work that was not dependent on the substation completion was advanced into FY 2014 due to an earlier than expected completion of permitting and the availability of resources to begin construction.

- The Coventry Substation project was $300,000 over the FY 2014 budget. This project was not budgeted for FY 2014 because it was placed in service in FY 2013, but had some carryover of final work and payments into FY 2014.

- Chase Hill was approximately $340,000 over-budget due to additional accruals of material costs in FY 2014.

- The Johnston 18F10 project was approximately $380,000 over-budget due to accelerating the schedule of work into FY 2014. This project is now complete.

- The Reconductor 2228 Project had a variance above budget of approximately $190,000 due primarily to the timing of final payments to the construction contractor in FY 2014 for work completed in FY 2013.

Offsetting a portion of the variance in the Load Relief budget classification from the projects noted above is a spending below budget for the fiscal year on the following projects:

- The Volt/VAR Project spending was approximately $440,000 under-budget for the fiscal year due primarily to a delay in negotiating communications vendor contracts. In addition, the transfer of approximately $100,000 of preliminary engineering work to the project did not occur in FY 2014.

- The Newport project spending is below budget for FY 2014 primarily due to a delay in obtaining a 'special use permit' for the substation. At this time, the Company continues with preliminary engineering and the permitting process on the project.

The Reliability budget category is $400,000 over-budget. This is driven primarily by work on EMS replacements due to changes in timing and significantly higher engineering and design costs.

The following projects involve projected spending below budget, which will offset a portion of the variance from the EMS projects:

- As discussed in the Company's FY 2014 Second Quarter Electric ISR Plan Report, the Tunk Hill project was originally budgeted on an investment grade estimate. After the detailed design was completed, the scope of work was less than originally estimated. In addition, delays were experienced due to permitting requirements winter conditions. This project is expected to be completed early in FY 2015.

- The Feeder Hardening budget of $200,000 for FY 2014 was not spent because Verizon pole sets are still required to complete the remaining work under this project. The Company expects to complete the work on this project in FY 2015.

The driver for the remaining variance in the System Capacity and Performance spending rationale is attributable to work on the majority of the individual projects progressing as budgeted, and not requiring full use of the negative schedule reserve included in the fiscal year budget. The Company uses negative schedule reserves in the System Capacity and Performance budget category with the goal of eliminating churn when projects do not proceed as scheduled due to delays from things such as permitting, obtaining easements, telephone pole sets or other issues that were unknown at the time the budget was finalized.

Table 8

SPENDING RATIONALE	Budget Classiciation	FY2014 Budget	FY 14 Actual Spending	Variance
System Capacity and Peformance	Load Relief	$10,396,500	$22,762,125	$12,365,625
	Reliability	$1,947,500	$3,210,213	$1,262,713
	Reliability - Feeder Hardening	$200,000		($200,000)
	System Capacity and Performance Sub-Total	**$12,544,000**	**$25,972,338**	**$13,428,338**

c. **<u>FY 2014 Work Plan Accomplishments</u>**

Table 9 below provides actual work plan accomplishments for FY 2014 as compared to FY 2013 for distribution line program work. During FY 2014, the Company made significant progress on many multi-year specific projects. The Company also completed and placed in service the new Shun Pike substation.

Table 9

Actual Work Plan Accomplishments for FY 2014

Program Type	FY13 Accomplishments	FY14 Accomplishments	Commments
Distribution Transformer Upgrades	573	572	104% Completed
Cutouts Replaced	4,000	934	Cutouts are now included in the I&M Program and no longer tracked separately
Network Protectors	0	3	
I&M Program	15,229 hours	43,344 hours	12 feeders 100% completed with 4 feeders partially completed

III. FY 2014 Vegetation Management

As shown below in Table 10, overall, the total Vegetation Management spending for FY 2014 was $8.530 million as compared to a budget of $8.476 million.[5] The Company completed 102 percent of the annual distribution mileage cycle trimming goal, with an associated spend of 98 percent of the FY 2014 cycle trimming budget. The Company was able to come in under budget in the cycle trimming, and hazard tree programs because of an aggressive and competitive bidding program. However, police and flagging costs have continued to rise again this year. This is primarily due to an increased number of towns requiring police details where such details were not previously required. In an effort to reduce and more accurately forecast these costs, the Forestry Department, in conjunction with Community Relations and the Company's Gas Department, have been meeting with local public safety officials prior to beginning work. In addition, the Company continues to work with its contractors to find ways to work safely and more efficiently to reduce costs. This includes working with contractors to reduce and control police detail costs. As part of this effort, police costs are now tracked for each contractor, and the Company has established specific targets for all contractors. The Company terminated a contract with one of its vendors in the last quarter of FY 2014 because of safety issues. Consequently, the Company missed its mileage targets for sub-transmission in FY 2014. The remaining work will be completed in FY 2015.

Finally, regarding the issues with Verizon Communications ("Verizon"), in accordance with the Inter-Company Operating Procedures ("IOP"), on March 24, 2014, the Company sent correspondence to Verizon outlining the Company's plans for cycle pruning and hazard tree removal work for FY 2015 and requesting that Verizon identify the pole lines that require joint trimming. On April 17, 2014, Verizon responded to the Company's March 24 request, declining to participate in joint trimming work.

On June 30, 2014, Verizon notified the Company that it was terminating Section 7 of IOP-J, effective July 31, 2014, and that absent a new agreement, each party would be responsible for its own tree trimming and clearing of facilities going forward. In compliance with the Company's settlement with the Rhode Island Division of Public Utilities and Carriers in Docket No. 4473, the Company remains in discussions with Verizon in efforts to resolve the vegetation management spending issues with Verizon.

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[5] The Vegetation Management costs do not include costs for major storms, such as Hurricane Sandy or the Winter Storm on February 7, 2013. Those costs will be included in the Company's cost recovery filing(s) in Docket No. 2509.

Table 10[6]

O&M Vegetation Management Expenditures

	FY2014 Total		
	Budget	**Actual**	**Variance**
Vegetation Management			
Cycle Trimming	$5,230,000	$5,109,769	($120,231)
Hazard Tree	$750,000	$699,867	($50,133)
Sub T (on & off road)	$724,000	$639,497	($84,503)
Police Detail	$525,000	$768,950	$243,950
Core Crew (all other)	$1,247,000	$1,311,732	$64,732
Total FY2014 Vegetation Management	**$8,476,000**	**$8,529,815**	**$53,815**

	FY2014 Goal	**FY2014 Completed**	**Annual % Completed vs FY 2014 Goal**
Distribution Mileage Trimming (miles)	1,321	1,348	102%
SubT Sideline Pruning and Hazard Tree Removal (miles)	38	29	76%
SubT Floor Treatment (acres)	208	143	69%

[6] The Sub-Transmission FY 2014 Goals for miles and acres have been adjusted to remove Transmission miles that were inadvertently included in the original FY 2014 plan.

IV. <u>FY 2014 Inspection and Maintenance</u>

As shown in Table 11 below, expenses related to capital spending for the I&M program were over-budget for FY 2014. However, inspections and repair-related spending for the I&M program was under-budget. These variances from budget were driven by more work categorized as Opex related to Capex and less work categorized as expense only, based on the work found in the field. Overall, the total I&M costs were $3.6 million, which was approximately $0.1 million lower than the original ISR budget. For FY 2014, 100% of the annual inspection goal was completed.

Table 11
US Electric Distribution - Rhode Island
I&M Program Expenditures
FY 2014

	FY 2014 Total		
	Budget	Actual	Variance
Opex Related to Capex	$1,286,300	$1,818,389	$532,089
Inspection and Repair Related Costs	$2,492,700	$1,793,569	($699,131)
Total O&M Expenses	$3,779,000	$3,611,958	($167,042)

	FY 2014 Goal	FY 2014 Completed	Annual % Completed vs FY 2014 Goal
RI Distribution Overhead Structures Inspected	57,352	58,668	102%

Over the past several years, the Inspection & Maintenance program has been ramping up to full implementation. In FY 2011, the Company started performing inspections on its overhead distribution system; in FY 2012, the Company started performing repairs based on those inspections. The Company categorizes the deficiencies found as Level I, II, or III, and repairs Level I deficiencies either immediately or within approximately one week of the inspection. The Company bundles Level II and III work for planned replacement. At the end of FY 2014, the Company completed repairs reported for approximately 20% of the deficiencies found. The table below shows the total deficiencies found and repairs made.

Summary of Deficiencies and Repair Activities - RI Distribution				
Year Inspection Performed	**Priority Level / Repair Expected**	**Deficiencies Found (Total)**	**Repaired as of 4/14/14**	**Not Repaired as of 4/14/14**
FY11				
	I	19	19	0
	II	13,147	11,795	1,352
	III	38	4	34
FY12				
	I	20	20	0
	II	15,870	7,872	7,998
	III	667	12	655
FY13				
	I	17	17	0
	II	26,885	7	26,878
	III	7,654	0	7,654
FY14				
	I	11	11	0
	II	23,032	1	23,031
	III	8,742	0	8,742
Total Since Program Inception		**96,102**	**19,758**	**76,344**

As shown in the table below, for streetlight inspections, results of the Company's manual elevated voltage testing for FY 2014 reflect seven instances of elevated voltage readings of one volt or more. For the overhead and underground manual elevated voltage inspections, there were no instances of elevated voltage.

Manual Elevated Voltage Testing	Total Sysem Units Requiring Testing	FY 2014 YTD Units Completed 3-31-14	Percent Completed	Units with Voltage (>=1.0v)	Percent of Units Tested with Voltage (>=1.0v)
Distribution Overhead Facilities	288,345	51,125	17.73%	0	0.000%
Street Lights*	5,888	2,528	100%	7	0.277%
Underground	13,870	3,250	23.43%	0	0.000%

*The Rhode Island Street Light Elevated Voltage Testing Program moved from a five-year to a three-year program. Elevated voltage tests were performed on 2,528 assets in FY 2014, for a total completion rate of 100% in the three-year cycle ending in FY 2014. The new three-year cycle will begin in FY 2015.

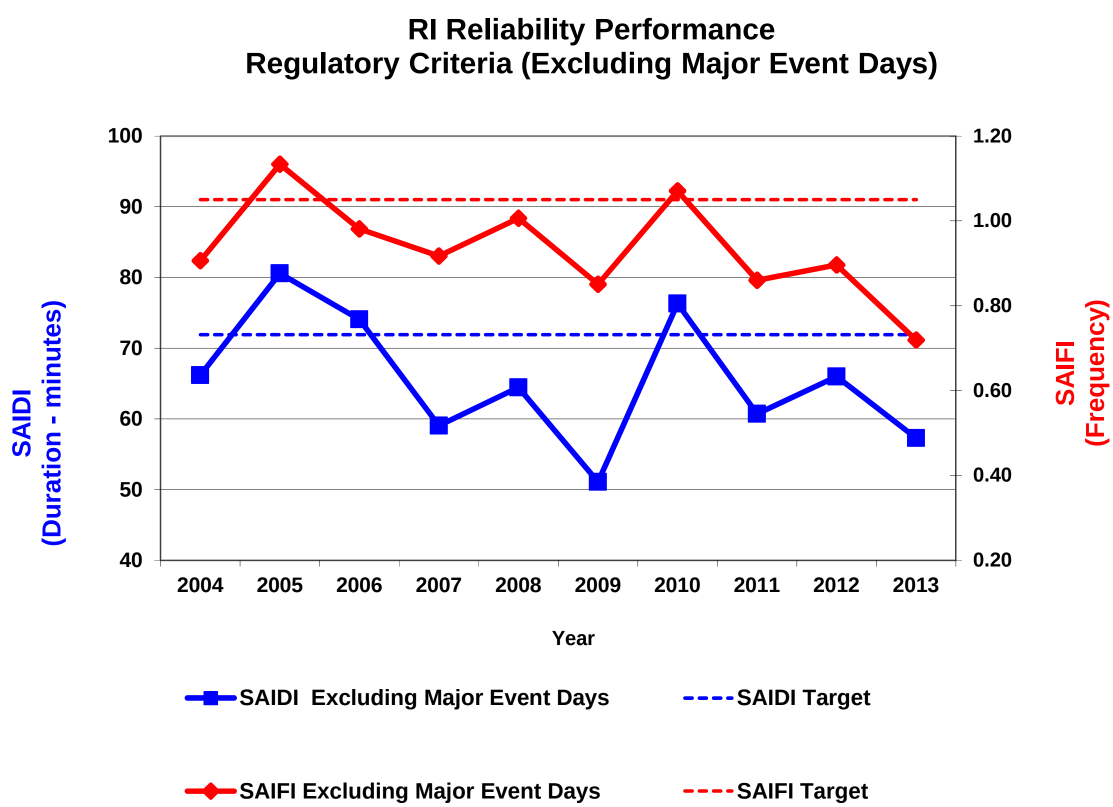
Mobile elevated voltage testing was completed in FY 2014, as detailed in the Company's Annual Contact Voltage Report filed with the PUC on June 26, 2014. The FY 2014 mobile elevated voltage testing and its associated manual testing revealed 18 instances of elevated voltage readings of one volt or more. Fifteen of these elevated voltage readings were on Company-owned street lights and three were on Customer-owned street lights.

In FY 2013 and FY 2014, mobile elevated voltage testing was performed in March of the end of each fiscal year. The FY 2013 mobile testing and repair costs are included in this FY 2014 ISR Reconciliation because the contactor invoice was paid in FY 2014, and the repairs were performed in FY 2014. The FY 2014 testing costs are also included in this Reconciliation because the contractor invoice for the mobile testing was paid by March 31, 2014. Repair costs and quality assurance manual testing costs for the FY 2014 program were incurred in FY 2015 and are, therefore, not included in this filing.

V. Reliability Performance

The Company met both its System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Duration Index ("SAIDI") performance metrics in calendar year 2013 ("CY 2013"), with SAIFI of 0.72 against a target of 1.05, and SAIDI of 57.28 minutes, against a target of 71.9 minutes. The Company's annual service quality targets are measured by excluding major event days.[7] A comparison of reliability performance in CY 2013 relative to that of previous years is shown in Table 12. The Company's performance has shown a downward (improving) trend over the past several years with major event days excluded.

Table 12



[7] Major Event Day ("MED") is defined as a day in which the daily system SAIDI exceeds a MED threshold value (5.74 minutes for 2013). For purposes of calculating daily system SAIDI, any interruption that spans multiple calendar days is accrued to the day on which the interruption began. Statistically, days having a daily system SAIDI greater than the MED are days on which the energy delivery system experiences stress beyond that normally expected, such as during severe weather.

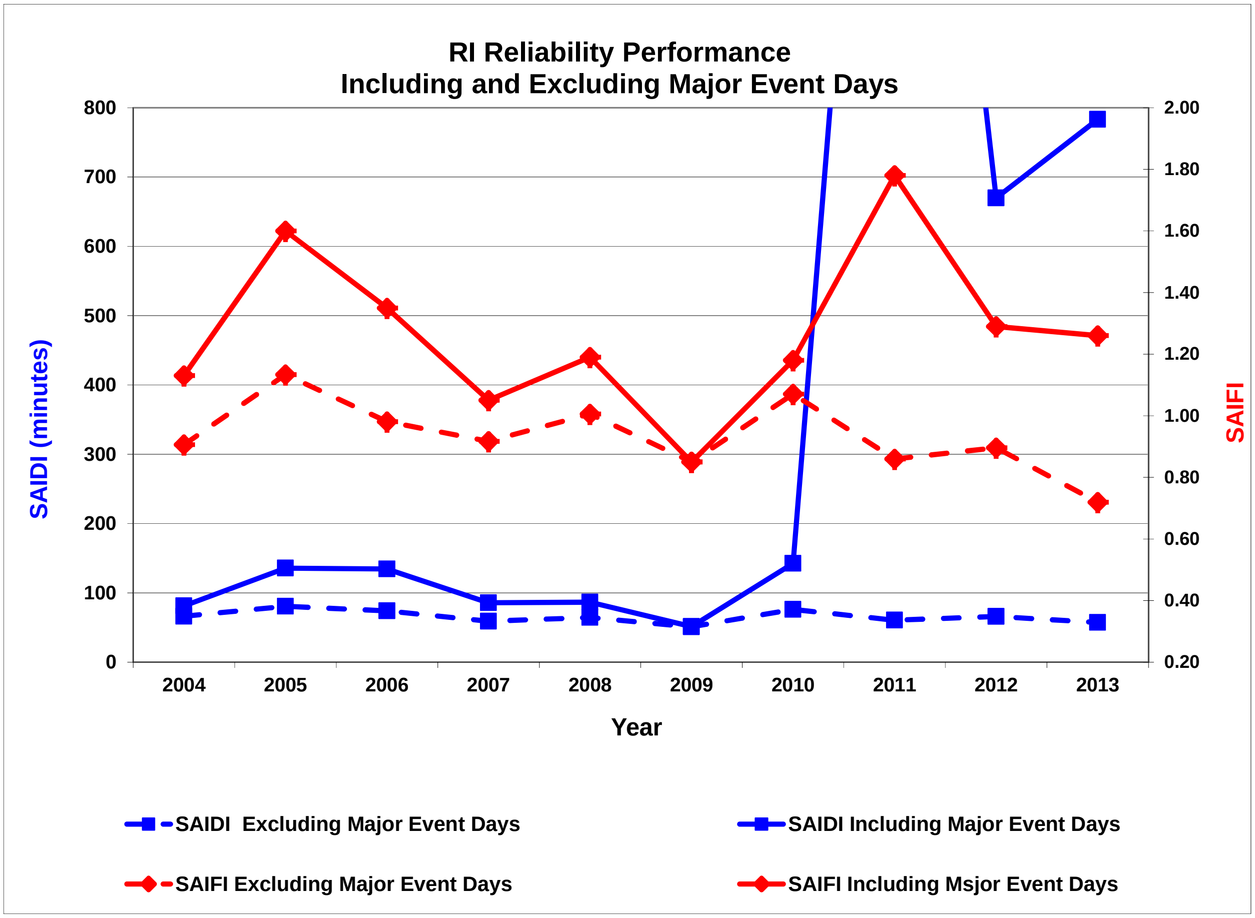
Calendar year 2013 had three days from two separate events that were characterized as major event days. The most significant single event was the Nor'easter on February 8, 2013**.** As a result of this storm, approximately 238,000 customers were interrupted with all customers restored by February 13. Only the first two days of the storm exceeded the major event day threshold of 5.74 minutes. Table 13 below shows all events in 2013 that are characterized as major event days.

Table 13

Event	**Dates Excluded**	**Total Customers Interrupted/Daily SAIDI**
January 31st Winter Storm	January 31, 2013	January 31: 36,734 CI/12.28 minutes
February 8th Nor-easter ('Nemo")	February 8, 2013 to February 9, 2013 (2 days)	February 8: 210,459 CI/674.59 minutes February 9: 17,714 CI/40.09 minutes

Reliability performance, both including and excluding major event days, is shown in Table 14 for 2004 through 2013. SAIDI for 2011, including major event days, exceeds the scale of the chart, at 1,947 minutes (32.5 hours). This was driven by Tropical Storm Irene. As shown in the graph in Table 14, 2011, 2012, and 2013 show the greatest differences between performance with and without major event days. In 2011, the Company experienced ten major events days from five events; Tropical Storm Irene and the October Snowstorm accounted for seven of these major event days. In 2012, the Company experienced four major event days from two events. Hurricane Sandy accounted for three of these major event days. As previously noted, 2013 performance, including major event days, was driven by the February 8 Nor'easter.

Table 14


RI Reliability Performance
Including and Excluding Major Event Days
SAIDI (minutes)
SAIFI
800
700
600
500
400
300
200
100
0
2.00
1.80
1.60
1.40
1.20
1.00
0.80
0.60
0.40
0.20
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
Year
SAIDI Excluding Major Event Days
SAIDI Including Major Event Days
SAIFI Excluding Major Event Days
SAIFI Including Msjor Event Days

**Testimony of
William R. Richer**

PRE-FILED DIRECT TESTIMONY

OF

WILLIAM R. RICHER

August 1, 2014

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I. INTRODUCTION

Q. Please state your full name and business address.

A. My name is William R. Richer, and my business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

Q. By whom are you employed and in what capacity?

A. I am the Director of Revenue Requirements-Rhode Island for National Grid USA Service Company, Inc. ("Service Company"). The Service Company provides engineering, financial, administrative, and other technical support to subsidiary companies of National Grid USA. My current duties include revenue requirements oversight for National Grid's electric and gas distribution activities in the US, including the electric division of The Narragansett Electric Company, d/b/a National Grid ("Narragansett" or "Company").

Q. Please describe your education and professional experience.

A. In 1985, I earned a Bachelor of Science degree in Accounting from Northeastern University. During my schooling, I interned at the public accounting firm Pannell Kerr Forster in Boston, Massachusetts as a staff auditor and continued with this firm after my graduation. In February 1986, I joined Price Waterhouse in Providence, Rhode Island where I worked as a staff auditor and senior auditor. During this time, I earned my certified public accountants license in the State of Rhode Island. In June 1990, I joined National Grid in the Service Company (then known as New England Power Service Company) as a supervisor of Plant Accounting. Since that time, I have held various positions within the Service Company, including Manager of Financial Reporting, Principal Rate Department Analyst, Manager of General Accounting, Director of Accounting Services, and Assistant Controller.

Q. Have you previously testified before the Rhode Island Public Utilities Commission ("PUC")?

A. Yes. I have testified before the PUC on numerous occasions. This testimony is intended to supplement the previous testimony I provided in this docket concerning revenue requirements.

Q. What is the purpose of your testimony?

A. In this docket, the PUC approved a new Electric Infrastructure, Safety and Reliability ("ISR") factor, which went into effect on April 1, 2013. That factor was based on a projected fiscal year ("FY") 2014 ISR revenue requirement of $12,133,495 for the estimated operation and maintenance ("O&M") work associated with the Company's vegetation management ("VM") and inspection and maintenance ("I&M") programs for the Company's FY ended March 31, 2014. The factor was also based on the estimated ISR plant additions during the Company's FY ended March 31, 2014, 2013, and 2012, and which were incremental to the levels reflected in rate base in the Company's last base rate case (Docket No. 4323). The purpose of my testimony is to present an updated FY 2014 ISR revenue requirement associated with actual FY 2014 O&M programs, the FY 2014, FY 2013, and FY 2012 incremental plant additions, and actual tax deductibility percentages for FY 2013 capital additions. Actual tax deductibility percentages for FY 2014 plant additions will not be known until the Company files its FY 2014 income tax return in December 2014. Finally, the updated FY 2014 revenue requirement includes an adjustment associated with the ISR property tax recovery formula that was approved in Docket No. 4323. The ISR property tax recovery adjustment became effective for periods subsequent to rate year in Docket No. 4323, which ended on January 31, 2014. Consequently, the ISR property tax recovery adjustment covers only the months of February and March of 2014. As shown on Attachment WRR-1, Page 1 at Line 13, the updated FY 2014 ISR revenue requirement collectible through the Company's ISR factor for the FY 2014 period totals $10,981,596.

Q. Are there any schedules attached to your testimony?

A. Yes, I am sponsoring the following Attachment:

- Attachment WRR-1: Electric Infrastructure, Safety, and Reliability Plan Revenue Requirement Reconciliation

II. ISR PLAN FY 2014 REVENUE REQUIREMENT

Q. Did the Company calculate the updated FY 2014 ISR revenue requirement the same way it calculated the revenue requirement in the previous ISR Factor submissions and ISR reconciliations?

A. The updated FY 2014 ISR revenue requirement calculation is nearly identical to the ISR revenue requirement used to develop the approved ISR factors that were effective April 1, 2013, and which I described previously in my testimony in this proceeding. However, the updated FY 2014 revenue requirement calculation now incorporates updated ISR investment amounts, the approved weighted average cost of capital from Docket No. 4323, and known tax deductibility percentages. The only change to the ISR revenue requirement calculation in this reconciliation is that it now includes the ISR property tax recovery formula adjustment. Therefore, please refer to my previous testimony in this docket for a detailed description of the revenue requirement calculation. This testimony is limited to the following: (1) a description of the impact of Docket No. 4323 to the electric ISR revenue requirement, (2) a summary of the revenue requirement update shown on Page 1 of Attachment WRR-1, (3) a discussion of the change in the calculation of tax depreciation to coincide with tax depreciation taken on the Company's FY 2012 federal income tax return filed in December of 2012, and (4) a description of the ISR property tax recovery formula adjustment.

Q. Please describe the impact on the FY 2014 ISR revenue requirement recoverable through the FY 2014 ISR factor as a result of the implementation of new electric base distribution rates, which the PUC approved in Docket No. 4323 and put into effect on February 1, 2013.

A. The ISR mechanism was established to allow the Company to recover outside of base rates its costs associated with plant additions incurred to expand its electric infrastructure and improve the reliability and safety of its electric facilities. When new base rates are implemented, as was the case in Docket No. 4323, the costs the Company recovers for pre-rate case ISR plant additions are no longer recovered through a separate ISR factor. Instead, these costs are recovered through base rates, and the underlying ISR plant additions become a component of base distribution rate base from that point forward. In April 2012, in Docket No. 4323, the Company filed a request with the PUC seeking a change in base rates for its electric and gas distribution businesses. At the end of the proceedings in Docket No. 4323, the PUC approved a settlement agreement between the Company, Rhode Island Division of Public Utilities and Carriers ("Division"), and the U.S. Department of the Navy and established new base rates for the Company. The Company's rate base reflected in its April 2012 request to the PUC in Docket No. 4323 reflected projected plant additions through January 31, 2014. In its base rate request, the Company proposed to maintain consistency with the existing ISR mechanism for the FY 2012 and FY 2013 periods. Consequently, the forecast used to develop rate base in the distribution rate case included the ISR approved plant additions levels for FY 2012, FY 2013, and ten months of FY 2014 (using the FY 2013 ISR approved plant additions level as a proxy for FY 2014). The effective date of new rates in Docket No. 4323 was February 1, 2013. Therefore, recovery of the approved FY 2013 ISR revenue requirement through the ISR factor stopped on January 31, 2013, and all future recovery of those forecasted FY 2012, FY 2013, and FY 2014 ISR plant additions will be through the Company's base rates.

Q. Please continue.

A. As a result of the implementation of new base rates pursuant to Docket No. 4323 effective February 1, 2013, the cumulative amount of forecasted ISR plant additions were rolled into base rates effective at that date. The FY 2014 revenue requirement for incremental FY 2012, FY 2013, and FY 2014 ISR investments reflect a full year of revenue requirement because none of these incremental investments are included in the Company's base rate rate-base. These incremental FY vintage amounts must remain in the ISR recovery mechanism as provided for in the terms of the approved settlement in Docket No. 4323.

Q. Please summarize the updated FY 2014 ISR revenue requirement.

A. As shown on Page 1, of Attachment WRR-1, the Company's FY 2014 Electric ISR Program revenue requirement includes two elements: (1) O&M expense associated with the Company's VM activities and system inspection, feeder hardening, and potted porcelain cutouts, as encompassed by the Company's I&M Program, and (2) the Company's capital investment in electric utility infrastructure. The description of these elements and the related amounts are supported by the direct testimony and supporting attachment of Ms. Jennifer L. Grimsley. Line 5 reflects the actual FY 2014 revenue requirement related to O&M expenses, or $11,950,733.

As shown on Page 1, at Line 12 of Attachment WRR-1, the revenue requirement associated with the Company's actual FY 2014 capital investment totals $(969,137). As previously noted, the total FY 2014 revenue requirement includes the full year revenue requirement on vintage FY 2014, FY 2013, and FY 2012 incremental ISR plant additions above or below the level of plant additions reflected in base distribution rates. In addition, the FY 2014 revenue requirement reflects a true-up for changes to previously estimated tax depreciation expense to align with tax depreciation rates used on the Company's FY 2013 tax return, which was filed in December 2013. The last component is the property tax recovery adjustment, which is described further in my testimony. The total actual FY 2014 ISR Plan revenue requirement for both O&M expenses and capital investment of $10,981,596 is shown on Line 13.

Q. Please describe how the attachment to your testimony is structured.

A. Page 1 of Attachment WRR-1 summarizes the individual components of the updated FY 2014 ISR revenue requirement. Lines 6, 7, and 8 represent the full year 2014 ISR revenue requirements for the incremental FY 2012, FY 2013, and FY 2014 ISR investments, or those investments not included in the Company's base rates, and as supported with detailed calculations on Pages 2, 4, and 6, respectively. Line 10 reflects the reconciliation of the approved FY 2013 ISR revenue requirement for vintage FY 2013 plant additions with the actual vintage FY 2013 revenue requirement on those investments. This reconciliation is necessary because the actual level of tax deductibility on FY 2013 investments was not known when the Company filed the FY 2013 and FY 2014 ISR Factor proposals. The calculation of the reconciliation amounts is shown on Page 10, and reflects the difference in the approved FY 2013 ISR revenue requirement on FY 2013 investments, and the updated revenue requirement for that fiscal year on FY 2013 ISR investments when incorporating the final tax deductibility levels. A detailed calculation of the updated FY 2013 revenue requirement is presented on page 4 of Attachment WRR-1.

Q. Please describe the ISR property tax recovery adjustment.

A. The method used to recover property tax expense under the ISR was modified by the rate case settlement agreement in Docket No. 4323. Pursuant to that settlement, when determining the base on which property tax expense is calculated for purposes of the ISR revenue requirement, the Company includes an amount equal to the base-rate allowance for depreciation expense and depreciation expense on incremental ISR plant additions in the accumulated reserve for depreciation that is deducted from plant in service. The ISR property tax recovery adjustment also includes the impact of any changes in the Company's effective property tax rates on base-rate embedded property, plus cumulative ISR net additions. Property tax impacts associated with non-ISR plant additions are excluded from the property tax recovery calculation. This provision of the settlement agreement became effective for ISR property tax recovery periods subsequent to the January 31, 2014 end of the rate year; specifically, the months of February and March 2014 for the FY 2014 Electric ISR reconciliation. The calculation of the ISR property tax recovery adjustment is presented on page 11.

Q. Has the Company provided support for the actual level of FY 2014 ISR eligible plant investments?

A. Yes. The description of the FY 2014 Electric ISR program and the amount of the incremental plant additions eligible for inclusion in the ISR Mechanism are supported by the direct testimony and supporting attachment of Company Witness, Jennifer Grimsley. The ultimate revenue requirement on the ISR eligible plant additions equals the return on the investment (i.e. average rate base at the weighted average cost of capital), plus depreciation expense and property taxes associated with the investment. Incremental ISR eligible plant additions for this purpose is intended to represent the net change in rate

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base for electric infrastructure investments, since the establishment of the Company's ISR mechanism effective April 1, 2011, and is defined as capital additions plus cost of removal, less annual depreciation expense included in the Company's rates, net of depreciation expense attributable to general plant. As discussed in the testimony of Ms. Grimsley, the actual ISR eligible plant additions for FY 2014 totals $56.1million associated with the Company's FY 2014 ISR Plan (electric infrastructure investment net of general plant).

Q. Please explain the distinction between non-discretionary and discretionary capital spending as they relate to the revenue requirement calculation.

A. For purposes of calculating the capital-related revenue requirement, investments in electric infrastructure have been divided into two categories: (1) non-discretionary capital investments, which principally represent the Company's commitment to meet statutory and/or regulatory obligations; and (2) discretionary capital investments, which represent all other electric infrastructure-related capital investment falling outside of the specifically defined non-discretionary categories. The amount of discretionary investment the Company is allowed to include in the revenue requirement calculation is subject to certain limitations as shown on Page 9 of Attachment WRR-1. The amount of discretionary capital investment the Company uses in the revenue requirement must be no greater than the cumulative amount of discretionary project spend as approved by the PUC in this proceeding. This means that the discretionary investment is limited to the lesser of actual cumulative discretionary capital additions or spending, or cumulative discretionary spending approved by the PUC in this docket. For purposes of the FY 2014 revenue requirement, the lesser of these items was actual discretionary capital additions of $25,356,524, as shown on Attachment WRR-1, Page 9.

Q. What is the updated revenue requirement associated with actual plant additions?

A. The updated FY 2014 revenue requirement associated with the Company's actual FY 2012 and FY 2014 ISR eligible plant investments totals $(969,137) and includes the updated FY 2014 revenue requirement on FY 2012, FY 2013,and FY 2014 investments, reconciliation of the approved FY 2013 and FY 2014 ISR revenue requirement for vintage FY 2013 investments with the actual vintage FY 2013 and FY 2014 revenue requirement on those investments, and the inclusion of the ISR property tax recovery formula adjustment.

III. <u>CONCLUSION</u>

Q. Does this conclude your testimony?

A. Yes, it does.

Attachment WRR-1

Attachment WRR-1 Electric Infrastructure, Safety, and Reliability Plan Revenue Requirement Calculation

The Narragansett Electric Company
d/b/a National Grid
FY 2014 Electric ISR Revenue Requirement Reconciliation
Summary

Line No.			Fiscal Year 2014
	Operation and Maintenance (O&M) Expenses:		
1	Current Year Vegetation Management (VM)	Attachment JLG-1 Page 18 of 24, Table 10	$8,529,815
2	Current Year Inspection & Maintenance (I&M)	Attachment JLG-1, Page 19 of 24, Table 11	$3,611,958
3	Electric Contact Voltage expenses included in R.I.P.U.C. Docket No. 4323 - FY 2014		($163,749)
4	Correction to Prior Year ISR for Electric Contact Voltage expenses included in R.I.P.U.C. Docket No. 4323 - For the months of February and March 2013	Line 4 * 2/12	($27,292)
5	**Total O&M Expense Component of Revenue Requirement**	Sum of Lines 1 through 4	$11,950,733
	Capital Investment:		
6	FY 2014 Revenue Requirement on FY 2014 Actual Incremental Capital Investment	Page 2 of 14 Line 30	$789,745
7	FY 2014 Revenue Requirement on FY 2013 Actual Incremental Capital Investment	Page 4 of 14, Line 51(b)	($1,388,236)
8	FY 2014 Revenue Requirement on FY 2012 Actual Incremental Capital Investment	Page 6 of 14, Line 51, Col (b)	($65,065)
9	Subtotal	Sum of Lines 6 through 8	($663,555)
10	True Up for Capital Repairs Deduction of FY2013 Revenue Requirement Reconciliation R.I.P.U.C. Docket No. 4307	Page 10 of 14 Line 3	($1,988)
11	FY 2014 Property Tax Recovery Adjustment	Page 11 of 14 Line 34	($303,593)
12	**Total Capital Investment Component of Revenue Requirement**	Sum of Lines 9 through 10	($969,137)
13	**Total Fiscal Year Revenue Requirement**	Line 5 + Line 12	$10,981,596

The Narragansett Electric Company
d/b/a National Grid
FY 2014 Electric ISR Revenue Requirement Reconciliation
FY 2014 Revenue Requirement on FY 2014 Actual Incremental Capital Investment

Line No.				Fiscal Year 2014 (a)
	Capital Investment Allowance			
1	*Non-Discretionary Capital*	Page 9 of 14, Line 1(c)		$6,923,860
	Discretionary Capital			
2	Lesser of Actual Cumulative Non-Discretionary Capital Additions or Spending, or Approved Spending	Page 9 of 14, Line 16(c)		$6,400,406
3	Total Allowed Capital Included in Rate Base	Line 1 + Line 2		$13,324,266
	Depreciable Net Capital Included in Rate Base			
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$13,324,266
5	Retirements	Page 8 of 14, Line 9(c)	1/	($4,165,367)
6	Net Depreciable Capital Included in Rate Base	Line 4 - Line 5		$17,489,633
	Change in Net Capital Included in Rate Base			
7	Capital Included in Rate Base	Line 3		$13,324,266
8	Depreciation Expense	Per Settlement Agreement Docket No. 4323, excluding General Plant	2/	7,173,397
9	Incremental Depreciable Amount	Line 7 - Line 8		$6,150,869
10	Total Cost of Removal	Page 8 of 14, Line 6(c)		($887,841)
11	**Total Net Plant in Service**	**Line 7 + Line 10**		**$12,436,425**
	Deferred Tax Calculation:			
12	Composite Book Depreciation Rate	As approved per R.I.P.U.C. Docket No. 4323		3.40%
13	Vintage Year Tax Depreciation:			
14	2014 Spend	Page 3 of 14, Line 20		$5,911,906
15	Cumulative Tax Depreciation	Current Year Line 14		$5,911,906
16	Book Depreciation	Line 6 * Line 12 * 50%		$297,324
17	Cumulative Book Depreciation	Current Year Line 16		$297,324
18	Cumulative Book / Tax Timer	Line 15 - Line 17		$5,614,582
19	Effective Tax Rate			35.00%
20	Deferred Tax Reserve	Line 18 * Line 19		$1,965,104
	Rate Base Calculation:			
21	Cumulative Incremental Capital Included in Rate Base	Line 11		$12,436,425
22	Accumulated Depreciation	-Line 17		($297,324)
23	Deferred Tax Reserve	-Line 20		($1,965,104)
24	Year End Rate Base	Sum of Lines 21 through 23		$10,173,997
	Revenue Requirement Calculation:			
25	Average Rate Base	Current Year Line 24 ÷ 2		$5,086,999
26	Pre-Tax ROR		3/	9.68%
27	Return and Taxes	Line 25 * Line 26		$492,421
28	Book Depreciation	Line 16		$297,324
29	Property Taxes	$0 in Year 1, then Prior Year (Line 6 + Line 10 + Line 17) * Property Tax Rate		-
30	**Annual Revenue Requirement**	**Sum of Lines 27 through 29**		**$789,745**

1/ Actual Retirements

2/ Depreciation Expense has been prorated for 2 months (February - March 2014)

3/ Weighted Average Cost of Capital as approved in R.I.P.U.C. Docket No. 4323

	Ratio	Rate	Rate	Taxes	Return
Long Term Debt	49.95%	4.96%	2.48%		2.48%
Short Term Debt	0.76%	0.79%	0.01%		0.01%
Preferred Stock	0.15%	4.50%	0.01%		0.01%
Common Equity	49.14%	9.50%	4.67%	2.51%	7.18%
	100.00%		7.17%	2.51%	9.68%

The Narragansett Electric Company
d/b/a National Grid
FY 2014 Electric ISR Revenue Requirement Reconciliation
Calculation of Tax Depreciation and Repairs Deduction on FY2014 Incremental Capital Investments

Line No.			Fiscal Year 2014 (a)
	Capital Repairs Deduction		
1	Plant Additions	Page 2 of 14, Line 3	$13,324,266
2	Capital Repairs Deduction Rate	Per Tax Department	18.60%
3	Capital Repairs Deduction	Line 1 * Line 2	$2,478,313
	Bonus Depreciation		
4	Plant Additions	Line 1	$13,324,266
5	Less Capital Repairs Deduction	Line 3	$2,478,313
6	Plant Additions Net of Capital Repairs Deduction	Line 4 - Line 5	$10,845,953
7	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department	100.00%
8	Plant Eligible for Bonus Depreciation	Line 6 * Line 7	$10,845,953
9	Bonus Depreciation Rate (April 2013 - December 2013)	1 * 75% * 50%	37.50%
10	Bonus Depreciation Rate (January 2014 - March 2014)	1 * 25% * 50%	0.00%
11	Total Bonus Depreciation Rate	Line 9 + Line 10	37.50%
12	Bonus Depreciation	Line 8 * Line 11	$4,067,232
	Remaining Tax Depreciation		
13	Plant Additions	Line 1	$13,324,266
14	Less Capital Repairs Deduction	Line 3	$2,478,313
15	Less Bonus Depreciation	Line 12	$4,067,232
16	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 13 - Line 14 - Line 15	$6,778,721
17	20 YR MACRS Tax Depreciation Rates		3.750%
18	Remaining Tax Depreciation	Line 16 * Line 17	$254,202
19	Cost of Removal	Page 2 of 14, Line 10	($887,841)
20	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 12, 18 and 19	$5,911,906

The Narragansett Electric Company
d/b/a National Grid
FY 2014 Electric ISR Revenue Requirement Reconciliation
FY 2014 Revenue Requirement on FY 2013 Actual Incremental Capital Investment

Line No.				Fiscal Year 2013 (a)	Fiscal Year 2014 (b)
			1/		
	Capital Additions Allowance				
	Non-Discretionary Capital				
1	Non-Discretionary Additions			($5,184,396)	$0
	Discretionary Capital				
2	Lesser of Actual Discretionary Capital Additions or Spending or Approved Spending			($1,850,463)	$0
3	Total Allowed Capital Included in Rate Base in Current Year	Line 1 + Line 2		($7,034,859)	$0
	Depreciable Net Capital Included in Rate Base				
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		($7,034,859)	$0
5	Retirements			$5,838,935	$0
6	Net Depreciable Capital Included in Rate Base	Column (a) = Line 4 - Line 5; Columns (b), (c), & (d) = Prior Year Line 6		($12,873,794)	($12,873,794)
	Change in Net Capital Included in Rate Base				
7	Capital Included in Rate Base	Line 3		($7,034,859)	$0
8	Depreciation Expense	As approved per R.I.P.U.C. Docket No. 4065, excluding general plant		$0	$0
9	Incremental Depreciable Amount	Column (a) = Line 7 - Line 8; Columns (b), (c) & (d) = Prior Year Line 9		($7,034,859)	($7,034,859)
10	Total Cost of Removal			($1,895,059)	($1,895,059)
11	**Total Net Plant in Service**	**Line 9 + Line 10**		**($8,929,918)**	**($8,929,918)**
	Deferred Tax Calculation:				
12	Composite Book Depreciation Rate	As approved per R.I.P.U.C. Docket No. 4065		3.40%	3.40%
13	Tax Depreciation	Page 7 Line 20		($5,970,630)	($221,954)
14	Cumulative Tax Depreciation	Prior Year Line 17 + Current Year Line 16		($5,970,630)	($6,192,584)
15	Book Depreciation	Column (a) = Line 6 * Line 12 * 50%; Columns (b), (c) & (d) = Line 6 * Line 12		($218,854)	($437,709)
16	Cumulative Book Depreciation	Prior Year Line 16 + Current Year Line 15		($218,854)	($656,563)
17	Cumulative Book / Tax Timer	Line 14 - Line 16		($5,751,776)	($5,536,021)
18	Effective Tax Rate			35.00%	35.00%
19	Deferred Tax Reserve	Line 17 * Line 18		($2,013,121)	($1,937,607)
	Rate Base Calculation:				
20	Cumulative Incremental Capital Included in Rate Base	Line 11		($8,929,918)	($8,929,918)
21	Accumulated Depreciation	- Line 16		$218,854	$656,563
22	Deferred Tax Reserve	- Line 19		$2,013,121	$1,937,607
23	Year End Rate Base	Sum of Lines 20 through 22		($6,697,942)	($6,335,747)
	Revenue Requirement Calculation:				
24	Average Rate Base	(Prior Year Line 23 + Current Year Line 23) ÷2		($3,348,971)	($6,516,845)
25	Pre-Tax ROR		2/	9.84%	9.68%
26	Return and Taxes	Line 24 * Line 25		($329,539)	($630,831)
27	Book Depreciation	Line 15		($218,854)	($437,709)
28	Property Taxes	$0 in Year 1, then Prior Year (Line 11-Line 16) * Property Tax Rate	3/	$0	($319,696)
29	**Annual Revenue Requirement**	**Sum of Lines 26 through 28**		**($548,393)**	**($1,388,236)**

1/ Column (a) - FY 2013 Electric ISR Reconciliation Filing R.I.P.U.C. Docket No. 4307
2/ Weighted Average Cost of Capital as approved in R.I.P.U.C. Docket No. 4065 (Settlement)

	Ratio	Rate	Rate	Taxes	Return
Long Term Debt	46.05%	5.30%	2.44%		2.44%
Short Term Debt	4.98%	1.60%	0.08%		0.08%
Preferred Stock	0.19%	4.50%	0.01%		0.01%
Common Equity	48.78%	9.80%	4.78%	2.57%	7.35%
	100.00%		7.31%	2.57%	9.88%

Weighted Average Cost of Capital as approved in R.I.P.U.C. Docket No. 4323

		Ratio	Rate	Rate	Taxes	Return
	Long Term Debt	49.95%	4.96%	2.48%		2.48%
2/	Short Term Debt	0.76%	0.79%	0.01%		0.01%
	Preferred Stock	0.15%	4.50%	0.01%		0.01%
	Common Equity	49.14%	9.50%	4.67%	2.51%	7.18%
		100.00%		7.17%	2.51%	9.68%

	Tax-Effected Weighted Cost		Blended Tax-Effected Weighted Cost
R.I.P.U.C. Docket No. 4065	9.88%	Apr 12 - Jan 13	8.23%
R.I.P.U.C. Docket No. 4323	9.68%	Feb 13 - Mar 13	1.61%
			9.84%

3/ FY 2014 effective property tax rate of 3.67% per Page 11 of 14 Line 9(h)

The Narragansett Electric Company
d/b/a National Grid
FY 2014 Electric ISR Revenue Requirement Reconciliation
Calculation of Tax Depreciation and Repairs Deduction on FY2013 Incremental Capital Investments

			Fiscal Year 2013	Fiscal Year 2014
			(a)	(b)
	Capital Repairs Deduction			
1	Plant Additions	Page 6 Line 3	($7,034,859)	
2	Capital Repairs Deduction Rate		12.59%	
3	Capital Repairs Deduction	Line 2 * Line 3	($885,689)	
	Bonus Depreciation			
4	Plant Additions	Line 1	($7,034,859)	
5	Less Capital Repairs Deduction	Line 3	($885,689)	
6	Plant Additions Net of Capital Repairs Deduction	Line 4 - Line 5	($6,149,170)	
7	Percent of Plant Eligible for Bonus Depreciation		100.00%	
8	Plant Eligible for Bonus Depreciation	Line 6 * Line 7	($6,149,170)	
9	Bonus Depreciation Rate (April 2012 - December 2012)	1 * 75% * 50%	37.50%	
10	Bonus Depreciation Rate (January 2013 - March 2013)	1 * 25% * 50%	12.50%	
11	Total Bonus Depreciation Rate	Line 9 + Line 10	50.00%	
12	Bonus Depreciation	Line 8 * Line 11	($3,074,585)	
	Remaining Tax Depreciation			
13	Plant Additions	Line 1	($7,034,859)	
14	Less Capital Repairs Deduction	Line 3	($885,689)	
15	Less Bonus Depreciation	Line 12	($3,074,585)	
16	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 13 - Line 14 - Line 15	($3,074,585)	($3,074,585)
17	20 YR MACRS Tax Depreciation Rates		3.750%	7.219%
18	Remaining Tax Depreciation	Line 16 * Line 17	($115,297)	($221,954)
19	Cost of Removal	Page 6 Line 10	($1,895,059)	
20	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 12, 18, 19	($5,970,630)	($221,954)

The Narragansett Electric Company
d/b/a National Grid
FY 2014 Electric ISR Revenue Requirement Reconciliation
FY 2014 Revenue Requirement on FY 2012 Actual Incremental Capital Investment

Line No.				Fiscal Year 2012 (a)	Fiscal Year 2013 (b)	Fiscal Year 2014 (c)
	Capital Additions Allowance		1/			
	Non-Discretionary Capital					
1	Non-Discretionary			($4,019,686)	$0	$0
	Discretionary Capital					
2	Lesser of Actual Discretionary Capital Additions or Spending or Approved Spending			$4,163,942	$0	$0
3	Total Allowed Capital Included in Rate Base	Line 1 + Line 2		$144,256	$0	$0
	Depreciable Net Capital Included in Rate Base					
4	Total Allowed Capital Included in Rate Base in Current Year	Line 3		$144,256	$0	$0
5	Retirements			$19,938	$0	$0
6	Net Depreciable Capital Included in Rate Base	Column (a) = Line 4 - Line 5; Columns (b), (c), (d) & (e) = Prior Year Line 6		$124,318	$124,318	$124,318
	Change in Net Capital Included in Rate Base					
7	Incremental Depreciable Amount	Column (a) = Line 4, Columns (b), (c), (d) & (e) = Prior Year Line 7		$144,256	$144,256	$144,256
8	Cost of Removal			($771,131)	($771,131)	($771,131)
9	**Total Net Plant in Service**	**Line 7 + Line 8**		**($626,875)**	**($626,875)**	**($626,875)**
	Deferred Tax Calculation:					
10	Composite Book Depreciation Rate	As approved per R.I.P.U.C. Docket No. 4065		3.40%	3.40%	3.40%
11	Tax Depreciation	Page 9 Line 20		($654,965)	$2,107	$1,949
12	Cumulative Tax Depreciation	Prior Year Line 12 + Current Year Line 11		($654,965)	($652,858)	($650,909)
13	Book Depreciation	Column (a) = -Line 6 * Line 10 * 50%; Columns (b), (c), (d) & (e)= Line 6 * Line 10		($2,113)	($4,227)	($4,227)
14	Cumulative Book Depreciation	Prior Year Line 14 + Current Year Line 13		($2,113)	($6,340)	($10,567)
15	Cumulative Book / Tax Timer	Line 12 - Line 14		($652,852)	($646,518)	($640,342)
16	Effective Tax Rate			35.00%	35.00%	35.000%
17	Deferred Tax Reserve	Line 15 * Line 16		($228,498)	($226,281)	($224,120)
	Rate Base Calculation:					
18	Cumulative Incremental Capital Included in Rate Base	Line 9		($626,875)	($626,875)	($626,875)
19	Accumulated Depreciation	Line * Line 18		$2,113	$6,340	$10,567
20	Deferred Tax Reserve	- Line 17		$228,498	$226,281	$224,120
21	Year End Rate Base	Sum of Lines 18 through 20		($396,264)	($394,254)	($392,188)
	Revenue Requirement Calculation:					
22	Average Rate Base	(Prior Year Line 21 + Current Year Line 21) ÷2				($393,221)
23	Pre-Tax ROR		2/			9.68%
24	Return and Taxes	Line 22 * Line 23				($38,064)
25	Book Depreciation	Line 19				($4,227)
26	Property Taxes	$0 in Year 1, then Prior Year (Line 9 - Line 14) * Property Tax Rate	3/			($22,774)
27	**Annual Revenue Requirement**	**Sum of Lines 24 through 26**		**N/A**	**N/A**	**($65,065)**

1/ Column (a) - FY 2012 Electric ISR Reconciliation Filing R.I.P.U.C. Docket No. 4218.
2/ Weighted Average Cost of Capital per Settlement Agreement R.I.P.U.C. Docket No. 4323

	Ratio	Rate	Rate	Taxes	Return
Long Term Debt	49.95%	4.96%	2.48%		2.48%
Short Term Debt	0.76%	0.79%	0.01%		0.01%
Preferred Stock	0.15%	4.50%	0.01%		0.01%
Common Equity	49.14%	9.50%	4.67%	2.51%	7.18%
	100.00%		7.17%	2.51%	9.68%

3/ FY 2014 effective property tax rate of 3.67% per Page 11 of 14, Line 9(h)

The Narragansett Electric Company
d/b/a National Grid
FY 2014 Electric ISR Revenue Requirement Reconciliation
Calculation of Tax Depreciation and Repairs Deduction on FY2012 Incremental Capital Investments

Line No.				Fiscal Year 2012 (a)	Fiscal Year 2013 (b)	Fiscal Year 2014 (c)
	Capital Repairs Deduction					
1	Plant Additions	Page 3 Line 3		$144,256		
2	Capital Repairs Deduction Rate	Per Tax Department	1/	21.05%		
3	Capital Repairs Deduction	Line 2 * Line 3		$30,366		
	Bonus Depreciation					
4	Plant Additions	Line 1		$144,256		
5	Less Capital Repairs Deduction	Line 3		$30,366		
6	Plant Additions Net of Capital Repairs Deduction	Line 4 - Line 5		$113,890		
7	Percent of Plant Eligible for Bonus Depreciation	Per Tax Department	2/	85.00%		
8	Plant Eligible for Bonus Depreciation	Line 6 * Line 7		$96,807		
9	Bonus Depreciation Rate (April 2011 - December 2011)	1 * 75% * 100%		75.00%		
10	Bonus Depreciation Rate (January 2012 - March 2012)	1 * 25% * 50%		12.50%		
11	Total Bonus Depreciation Rate	Line 9 + Line 10		87.50%		
12	Bonus Depreciation	Line 8 * Line 11		$84,706		
	Remaining Tax Depreciation					
13	Plant Additions	Line 1		$144,256		
14	Less Capital Repairs Deduction	Line 3		$30,366		
15	Less Bonus Depreciation	Line 12		$84,706		
16	Remaining Plant Additions Subject to 20 YR MACRS Tax Depreciation	Line 13 - Line 14 - Line 15		$29,184	$29,184	$29,184
17	20 YR MACRS Tax Depreciation Rates			3.750%	7.219%	6.677%
18	Remaining Tax Depreciation	Line 16 * Line 17		$1,094	$2,107	$1,949
19	Cost of Removal	Page 3 Line 8		($771,131)		
20	Total Tax Depreciation and Repairs Deduction	Sum of Lines 3, 12, 18, 19		($654,965)	$2,107	$1,949

1/ Capital Repairs percentage is based on a three year average, 2010, 2011 and 2012 of electric property qualifying for the repairs deduction as a percentage of total annual plant additions.

2/ Since not all property additions qualify for bonus depreciation and because a project must be started after the beginning of the bonus period, January 1, 2008, an estimate of 85% is used rather than 100%.

The Narragansett Electric Company
d/b/a National Grid
FY 2014 Electric ISR Revenue Requirement Reconciliation
FY 2012 - 2014 Incremental Capital Investment Summary

Line No.			Actual Fiscal Year 2012 (a)	Actual Fiscal Year 2013 (b)	Fiscal Year 2014 (c)
	Capital Investment				
1	ISR - Eligible Capital Investment	Col (a) =FY 2012 ISR Reconciliation Filing Docket No. 4218, Att. WRR-1, Page 3 of 4, Line 20(b); Col (b) = FY 2013 ISR Reconciliation Filing Docket No. 4307, Att WRR-1, Page 7 of 12, Line 31 (b); Col (c) = Page 9 of 14, Line 22(b)	$48,946,456	$44,331,141	$56,129,551
2	ISR - Eligible Capital Additions included in Rate Base per R.I.P.U.C. Docket No. 4323	Schedule MDL-3-ELEC Page 53, Docket No. 4323: Col (a)= Line Note 1(a); Col (b)= Line Note 2(b); Col (c)= Line Note 3(e)	$48,802,200	$51,366,341	$42,805,284
3	Incremental ISR Capital Investment	Line 1 - Line 2	$144,256	($7,035,200)	$13,324,267
	Cost of Removal				
4	ISR - Eligible Cost of Removal	Col (a) =FY 2012 ISR Reconciliation Filing Docket No. 4218; Col (b)= FY 2013 Reconciliation Filing Docket No. 4307; Col (c) = Attachement JLG-1, Page 6 of 24, Table 2	$5,807,869	5,179,941	$5,007,992
5	ISR - Eligible Cost of Removal in Rate Base per R.I.P.U.C. Docket No. 4323	Workpaper MDL-19-ELEC Page 2, Docket No. 4323: Col (a)= Line Note 1(a); Col (b)= Line Note 2(b); Line Note 3(e)	$6,579,000	$7,075,000	$5,895,833
6	Incremental Cost of Removal	Line 4 - Line 5	($771,131)	($1,895,059)	($887,841)
	Retirements				
7	ISR - Eligible Retirements/Actual	Col (a)= FY 2012 ISR Reconciliation Filing Docket No. 4218; Col (b) = FY 2013 ISR Reconciliation Filing Docket No. 4307; Col (c) = Per Company Books	$7,740,446	14,255,714	$ 3,299,874
8	ISR - Eligible Retirements/Estimated	Col (a)= FY 2012 ISR Proposal Filing Docket No. 4218; Col (b)= FY 2013 ISR Proposal Filing Docket No. 4307; Col (c) = Line 2 (c) * 17.44% Retirement rate per Docket 4323 (Workpaper MDL-19-ELEC Page 3)	$7,720,508	$8,416,779	$7,465,242
9	Incremental Retirements	Line 7 - Line 8	$19,938	$5,838,935	($4,165,367)

The Narragansett Electric Company
d/b/a National Grid
FY 2014 Electric ISR Revenue Requirement Reconciliation
FY 2014 Capital Investment

Line No.			Actuals	In Base Rates Included in Docket No. 4323	Incremental Capital Investment
			(a)	(b)	(a) - (b) = (c)
	Non-Discretionary Capital				
1	**Total Allowed Non-Discretionary Capital Included in Rate Base Current Year**		**$30,773,027**	**$23,849,167**	**$6,923,860**
	Discretionary Capital				
2	FY 2012 Discretionary Capital **ADDITIONS**	Docket No. 4218 FY12 Reconciliation Filing, Att. WRR-1 Page 3 of 4, Line 10	$22,878,442		
3	FY 2013 Discretionary Capital **ADDITIONS**	Docket No. 4307 FY13 Reconciliation Filing, Att. WRR-1 Page 7 of 12, Line 16	$20,896,537		
4	FY 2014 Discretionary Capital **ADDITIONS**	Col (a) =Docket No. 4382 FY14 Proposal Sch. WRR-1 Page 7 of 11, Line 4; Col (b) = Att. JLG-1, Page 4 of 24, Table 1	$25,356,524		
5	Cumulative Actual Discretionary Capital Additions	Line 2 + Line 3 + Line 4	$69,131,503		
6	FY 2012 Discretionary Capital **SPENDING**	Docket No. 4218 FY12 Reconciliation Filing, Att. WRR-1 Page 3 of 4, Line 12	$24,424,047		
7	FY 2013 Discretionary Capital **SPENDING**	Docket No. 4307 FY13 Reconciliation Filing, Att. WRR-1 Page 7 of 12, Line 20	$21,589,109		
8	FY 2014 Discretionary Capital **SPENDING**	Col (b) = Att. JLG-1, Page 7 of 24, Table 3	$46,530,930		
9	Cumulative Actual Discretionary Capital Spending	Line 6 + Line 7 + Line 8	$92,544,086		
			As Approved in Docket No. 4382		
10	FY 2012 Approved Discretionary Capital **SPENDING**	Docket No. 4218 FY12 Reconciliation, Att. WRR-1 Page 3 of 4, Line 14	$27,036,150		
11	FY 2013 Approved Discretionary Capital **SPENDING**	Docket No. 4307 FY13 Reconciliation Filing, Att. WRR-1 Page 7 of 12, Line 24	$26,112,000		
12	FY 2014 Approved Discretionary Capital **SPENDING**	Docket No. 4382 FY14 Proposal Sch. WRR-1, Page 7 of 11, Line 5	$33,041,000		
13	Cumulative Actual Approved Discretionary Capital Spending	Line 10 + Line 11 + Line 12	$86,189,150		
			Total Allowed		
14	Cumulative Allowed Discretionary Capital Included in Rate Base	Lesser of Line 5, Line 9, or Line 13	$69,131,503		
15	Prior Year Cumulative Allowed Disretionary Capital Included in Rate Base	Docket No. 4307 FY13 Reconciliation Filing Att. WRR-1, Page 7, Line 27	$43,774,979		
16	**Total Allowed Discretionary Capital Included in Rate Base Current Year**	Line 14 - Line 15	**$25,356,524**	**$18,956,118**	**$6,400,406**
17	**Total Allowed Capital Included in Rate Base Current Year**	Line 1 + Line 16	**$56,129,551**	**$42,805,285**	**$13,324,266**

The Narragansett Electric Company
d/b/a National Grid
FY 2014 Electric ISR Revenue Requirement Reconciliation
True up for Capital Repairs Deduction on FY 2013 Capital Investment

Line No.			
	True Up FY 2013 Revenue Requirement on FY 2013 Capital Investment for Capital Repairs Deduction included in the FY 2013 Revenue Requirement Reconciliation R.I.P.U.C. Docket No. 4307		
1	Revenue Requirement using estimated capital repairs deduction rate of 16.00%	Docket No. 4307 FY13 Reconciliation, Attachment WRR-1, Page 2 of 12, Line 51	($546,405)
2	Revenue Requirement using actual capital repairs deduction rate of 12.59%	Page 4 of 14, Line 29(a)	($548,393)
3	True Up Amount	Line 2 - Line 1	($1,988)

The Narragansett Electric Company
d/b/a National Grid
FY 2014 Electric ISR Revenue Requirement Reconciliation
FY 2014 ISR Property Tax Recovery Calculation
(000s)

Line		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Effective tax Rate Calculation	**RY End**	**ISR Additions**	**Non-ISR Add's**	**Total Add's**	**Bk Depr (1)**	**Retirements**	**COR**	**End of FY 2014**
1	Plant In Service	$1,358,470	$9,335	$1,885	$11,220		$550		$1,370,240
2									
3	Accumulated Depr	$611,570				$7,498	$550	($835)	$618,783
4									
5	Net Plant	$746,900							$751,457
6									
7	Property Tax Expense	$29,743							$27,502
8									
9	Effective Prop tax Rate	3.98%							3.66%
10									
11	**Property Tax Recovery Calculation**								
12			**ISR YR 1**						
13									
14	ISR Additions		$9,335						
15	Rate Year Book Depr		($7,498)						
16	COR - ISR YR		$835						
17									
18	Net Plant Additions		$2,672						
19									
20	RY Effective Tax Rate		3.98%						
21	Year 1 ISR Property Tax Recovery			$106					
22	Year 2 ISR Property Tax Recovery								
23									
24	ISR Year Effective Tax Rate	3.66%							
25	RY Effective Tax Rate	3.98%	-0.32%						
26	RY Effective Tax Rate 2 mos		-0.05%						
27	RY Net Plant times 2 mo rate	$746,900	-0.05%	($401)					
28	ISR Yr 1 Net Adds	$2,672	-0.32%	($9)					
30				($410)					
31									
32	Total ISR Property Tax Recovery			($304)					
33									
34	Incremental ISR Property Tax Recovery			($304)					

Line Notes

1 Col (a) per Rate Year cost of service, Col (b), (cc), (d) and (f) per Actual ISR filing Col (e) equals Base Rate depreciation expense allowance
3 Col (a) per Rate Year cost of service, (e) equals Base Rate depreciation expense allowanceCol (h) Col (b), (cc), (d) and (f) per Actual ISR filing
7 Col (a) Base Rate property tax expense allowance
21 Line 18 times Line 20

The Narragansett Electric Company
d/b/a National Grid
FY 2014 Electric ISR Revenue Requirement Reconciliation
ISR Additions February and March 2014

Line No.	Month No.	Month	FY 2014 Plant Additions	In Rates	Not In Rates
			(a)	(b)	(c) = (a) - (b)
1					
2	1	Apr-13	4,677,463	4,280,528	396,934
3	2	May-13	4,677,463	4,280,528	396,934
4	3	Jun-13	4,677,463	4,280,528	396,934
5	4	Jul-13	4,677,463	4,280,528	396,934
6	5	Aug-13	4,677,463	4,280,528	396,934
7	6	Sep-13	4,677,463	4,280,528	396,934
8	7	Oct-13	4,677,463	4,280,528	396,934
9	8	Nov-13	4,677,463	4,280,528	396,934
10	9	Dec-13	4,677,463	4,280,528	396,934
11	10	Jan-14	4,677,463	4,280,528	396,934
12	11	Feb-14	4,677,463	-	4,677,463
13	12	Mar-14	4,677,463	-	4,677,463
14		Total	$56,129,551	$42,805,284	$13,324,267
15	**Total February & March 2014**				$ 9,354,925

Column (a)Page 8 of 14, Line 1(c)
Column(b) Page 8 of 14, Line 2(c)

The Narragansett Electric Company
d/b/a National Grid
FY 2014 Electric ISR Revenue Requirement Reconciliation
ISR Retirements February and March 2014

Line No.	Month No.	Month	FY 2014 Plant Retirements	In Rates	Not In Rates
			(a)	(b)	(c) = (a) - (b)
1					
2	1	Apr-13	274,990	746,524	(471,535)
3	2	May-13	274,990	746,524	(471,535)
4	3	Jun-13	274,990	746,524	(471,535)
5	4	Jul-13	274,990	746,524	(471,535)
6	5	Aug-13	274,990	746,524	(471,535)
7	6	Sep-13	274,990	746,524	(471,535)
8	7	Oct-13	274,990	746,524	(471,535)
9	8	Nov-13	274,990	746,524	(471,535)
10	9	Dec-13	274,990	746,524	(471,535)
11	10	Jan-14	274,990	746,524	(471,535)
12	11	Feb-14	274,990	-	274,990
13	12	Mar-14	274,990	-	274,990
14		Total	$3,299,874	$7,465,242	-$4,165,367
15	**Total February & March 2014**				$ 549,979

Column (a)Page 8 of 14, Line 7(c)
Column (b) Page 8 of 14 Line 8(c)

The Narragansett Electric Company
d/b/a National Grid
FY 2014 Electric ISR Revenue Requirement Reconciliation
ISR Cost of Removal February and March 2014

Line No.	Month No.	Month	FY 2014 Plant Cost of removal	In Rates	Not In Rates
			(a)	(b)	(c) = (a) - (b)
1					
2	1	Apr-13	417,333	589,583	(172,251)
3	2	May-13	417,333	589,583	(172,251)
4	3	Jun-13	417,333	589,583	(172,251)
5	4	Jul-13	417,333	589,583	(172,251)
6	5	Aug-13	417,333	589,583	(172,251)
7	6	Sep-13	417,333	589,583	(172,251)
8	7	Oct-13	417,333	589,583	(172,251)
9	8	Nov-13	417,333	589,583	(172,251)
10	9	Dec-13	417,333	589,583	(172,251)
11	10	Jan-14	417,333	589,583	(172,251)
12	11	Feb-14	417,333	-	417,333
13	12	Mar-14	417,333	-	417,333
14		Total	$5,007,992	$5,895,833	(887,841)
15	**Total February & March 2014**				$ 834,665

Column (a)Page 8 of 14, Line 4(c)
Column(b) Page 8 of 14 Line 5(c)

PRE-FILED DIRECT TESTIMONY

OF

SCOTT M. MCCABE

August 1, 2014

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I. <u>INTRODUCTION AND QUALIFICATIONS</u>

Q. Please state your full name and business address.

A. My name is Scott M. McCabe, and my business address is 40 Sylvan Road, Waltham, Massachusetts 02451.

Q. By whom are you employed and in what capacity?

A. I am Manager, New England Electric Pricing in the Regulation and Pricing group of National Grid USA Service Company, Inc. This department provides rate related support to The Narragansett Electric Company d/b/a National Grid (the "Company").

Q. Please describe your educational background and training.

A. I graduated from Bowdoin College in Brunswick, Maine with a Bachelor of Arts degree in Economics, and Government and Legal Studies in 1991.

Q. Please describe your professional experience?

A From 1991 to 1999, I was employed by Bay State Gas Company ("Bay State Gas"), headquartered in Westborough, Massachusetts. At Bay State Gas, I held several positions, beginning as an intern for the Marketing and Sales Group in September 1991 and was promoted to Associate Planning Analyst for the same group in January 1993. In August 1993, I joined the Demand Side Management department as a program manager responsible for the implementation of Bay State Gas' commercial and multifamily DSM

Programs. In August 1996, I joined Energy USA, an unregulated affiliate of Bay State Gas, as a Senior Financial Analyst. In December 1997 was promoted to Manager of Product Support. In January 1999, I rejoined Bay State Gas as Revenue Control and Analysis Supervisor. From May 1999 through April 2001, I worked for the Massachusetts Technology Collaborative as Project Manager for the Massachusetts Renewable Energy Trust. I joined National Grid in April 2001 as Senior Analyst in the Energy Efficiency Services Group. I transferred to Regulation and Pricing in October 2002. In July 2008, I was promoted to Lead Analyst, and in July of 2013, I was promoted to Principal Program Manager. Finally, in May 2014 I was promoted to my current position.

Q. Have you previously testified before Rhode Island Public Utilities Commission (“PUC”)?

A. No, I have not. However, I have testified extensively before the Massachusetts Department of Public Utilities and the New Hampshire Public Utilities Commission.

II. <u>PURPOSE OF TESTIMONY</u>

Q. What is the purpose of your testimony?

A. My testimony is in support of the Fiscal Year 2014 (“FY 2014”) Electric ISR Plan and presents the following:

- the results of the annual reconciliation of the actual FY 2014 capital investment revenue requirement and the Operations and Maintenance ("O&M") expense to the actual revenue billed;
- the status of the Fiscal Year 2012 ("FY 2012") CapEx and O&M reconciliations;
- the status of the Fiscal Year 2013 ("FY 2013") CapEx and O&M reconciliations;
- the proposed CapEx and O&M Reconciling Factors to be effective October 1, 2014; and
- the typical bill impacts related to the proposed reconciling factors.

Q. How is your testimony organized?

A. My testimony is organized as follows:

- Section III presents the Summary of FY 2014 CapEx and O&M Reconciliations;
- Section IV presents the results of the FY 2014 CapEx Revenue and the Actual CapEx Revenue Requirement Reconciliation, the calculation of the proposed CapEx Reconciling Factors, and the status of the refunds of the FY 2012 and FY 2013 CapEx reconciliation balances;
- Section V presents the results of the FY 2014 O&M Revenue and Expense Reconciliation, the calculation of the proposed O&M Reconciling Factor, and the status of the recovery of the FY 2012 O&M under-recovered balance, and the refund of the FY 2013 O&M over-recovered balance; and

- Section VI presents the rate class bill impact analysis.

III. SUMMARY OF FY 2014 CAPEX AND O&M RECONCILIATIONS

Q. Please summarize the results of the FY 2014 CapEx and O&M reconciliations.

A. A summary of the results of the FY 2014 CapEx and O&M reconciliations is presented in Attachment SMM-1. The annual reconciliations pursuant to the ISR Provision require the comparison of the actual revenue billed during the plan year through the approved CapEx and O&M Factors to the actual CapEx and O&M revenue requirement. The calculation of the actual revenue requirement is presented in the testimony of Company Witness William R. Richer. Attachment SMM-1 indicates that the result of the CapEx reconciliation is an over-recovery of $1.0 million and the result of the O&M reconciliation is an over-recovery of $0.4 million.

Q. Please briefly summarize the operation of the tariff provision that provides the Company the opportunity to recover certain costs through the ISR Plan.

A. In accordance with the ISR Provision, the Company is allowed to recover the revenue requirement related to capital investments through CapEx Factors and to recover the revenue requirement related to certain expenditures for Inspection and Maintenance (“I&M”) and Vegetation Management (“VM”) activities through O&M Factors.

In the ISR Plan filing for the upcoming plan year, the Company determines the CapEx Factors, which are designed to recover the revenue requirement on the forecasted capital investment for the ISR Plan's investment year, plus the cumulative revenue requirement associated with prior years' capital investments, and the O&M Factors which are designed to recover the forecasted plan year O&M expense. Afterward, on an annual basis, the Company is required to reconcile the actual cumulative CapEx revenue requirement and the actual O&M expense to actual billed revenue generated from the CapEx Factors and the O&M Factors. The over or under recovered balances resulting from the CapEx and O&M reconciliations are either refunded to or recovered from customers through the CapEx Reconciling Factors and the O&M Reconciling Factor, respectively.

IV. <u>CAPEX RECONCILIATION & PROPOSED CAPEX RECONCILING FACTORS</u>

Q. What is the result of the CapEx reconciliation for FY 2014?

A. The FY 2014 CapEx reconciliation by rate class is presented in Attachment SMM-2, page 1, Lines 4 through 6. Line 5 shows the CapEx Revenue billed during the period April 1, 2013 through March 31, 2014.Line 4 shows the actual CapEx Revenue Requirement credit amount of $1.0 million. Line 6 shows the over-recovered balance of $1.0 million, representing an over-recovery of this revenue requirement.

Q. Why has the Company prepared the CapEx Factor reconciliation by rate class?

A. The ISR Provision requires that the CapEx Reconciling Factors be calculated as class-specific per-kWh factors designed to recover or refund the under- or over-recovery of the actual Cumulative Revenue Requirement, as allocated to each rate class by the Rate Base Allocator, for the prior fiscal year. The Rate Base Allocator is the percentage of total rate base allocated to each rate class determined in the most recently-approved allocated cost of service study. Page 1, Line 4 of Attachment SMM-2 shows the allocation of the actual CapEx revenue requirement to each rate class based upon the Rate Base Allocator approved in the Company's 2012 general rate case in Docket No. 4323.

Q. Please describe the results of the rate class reconciliation.

A. As shown on Attachment SMM-2, page 1, the allocated actual FY 2014revenue requirement on capital investment, as shown on Line 4, is subtracted from the CapEx Factor revenue billed for each rate class, as shown on Line 5, resulting in an over-recovery from each rate class, as shown on Line 6, which totals approximately $1.1 million. The detail of each rate class' CapEx revenue billed is presented on Attachment SMM-2, page 2.

Q. Please describe the amount included on Line 7.

A. The amounts presented on Line 7 reflect the final balance related to the refund of the FY 2012 over-recovery reconciliation balance. The refund of the FY 2012 CapEx reconciliation balance is presented on page 3. Of the $65,588 over-recovery for FY 2012 approved by the PUC for refund, the Company refunded $40,055 from October 1, 2012 through September 30, 2013. As described in Docket No. 4307, the Company is including each rate class' residual balance with the FY 2014CapEx Reconciliation Factors.

Q. How is the Company proposing to refund the FY 2014 CapEx over-recovery?

A. The Company is proposing to implement a CapEx Reconciling Credit Factor for each rate class that is consistent with the results of the rate class reconciliation. The calculation of the proposed CapEx Reconciling Factors is presented in Attachment SMM-2, page 1. The over-recoveries on Line 8 are divided by each class' forecasted kWh deliveries for the period October 1, 2014 through September 30, 2015 on Line 9. The class-specific CapEx Reconciling Factors, as shown on Line 10, are as follows:

Rate Class	Charge/(Credit) per kWh
A-16 & A-60	(0.015¢)
C-06	(0.016¢)
G-02	(0.011¢)
G-32 & B-32	(0.007¢)
G-62 & B-62	(0.006¢)
Streetlights	(0.077¢)
X-01	(0.012¢)

Q. Is the Company providing the status of the over-recovery balance from the FY 2013 CapEx reconciliation?

A. Yes. The status of the refund of the FY 2013 CapEx reconciliation over-recovery balance is presented in Attachment SMM-2, page 4. As of June 30, 2014, the balance reflects a remaining over-recovery of $190,066, which the Company continues to credit to customers. The Company will continue to refund this balance through September 30, 2014.

Q. How will the Company propose to refund or recover any residual balances as of September 30, 2014?

A. Pursuant to the ISR Provision, the amount approved for recovery or refund through the CapEx Reconciling Factors is subject to reconciliation. Therefore, the Company will present the final reconciliation of balances from the FY 2013 reconciliation in the FY 2015 ISR Plan Reconciliation Filing and include each rate class' residual balance from the FY 2013 CapEx reconciliation with the FY 2015 CapEx Reconciliation Factors.

V. O&M RECONCILIATION & PROPOSED O&M RECONCILING FACTOR

Q. What is the result of the O&M reconciliation for FY 2014?

A. The O&M reconciliation for FY 2014 is presented in Attachment SMM-3, page 1. Line 2 shows O&M Revenue billed through the O&M Factors from April 1, 2013 through March 31, 2014 of approximately $12.4 million. Line 1shows the actual O&M expense for FY 2014 of approximately $12.0 million, which is supported in the testimony of Company Witnesses, Ms. Jennifer Grimlsey and Mr. Richer. Line 3 shows the difference of $406,114 representing an over-recovery.

Q. Please describe the amount included on Line 4.

A. The amount presented on Line 4 reflects the final balance related to the recovery of the FY 2012 O&M reconciliation under-recovered balance. The recovery of the FY 2012 O&M reconciliation balance is presented on page 3. Of the $159,045 under-recovery for FY 2012 approved by the PUC for recovery, the Company recovered $154,646 from October 1, 2012 through September 30, 2013. As described in Docket No. 4307, the Company is including the residual balance with the FY 2014 O&M Reconciliation Factor.

Q. Is the Company providing the O&M Factor Revenue?

A. Yes. Attachment SMM-3, page 2 presents the O&M Factor Revenue billed by month.

Q. What is the proposed O&M Reconciling Factor?

A. The proposed O&M Reconciling Factor is calculated on Attachment SMM-3, page 1. The over-recovery of $401,715 on Line 5 is divided by the forecasted kWhs during the recovery period, October 1, 2014 through September 30, 2015, on Line 6, resulting in a credit of (0.005¢) per kWh on Line 7.

Q. Why is the Company proposing a uniform per kWh O&M Reconciling Factor?

A. Pursuant to the ISR Provision, the O&M Reconciling Factor is a uniform per-kWh factor designed to recover or refund the under- or over-billing of actual I&M and VM expense for the prior fiscal year, based on forecasted kWhs during the recovery or refund period beginning October 1.

Q. Is the Company providing the status of the refund of the over-recovery of the FY 2013 O&M reconciliation?

A. Yes. The status of the balance from the FY 2013 O&M reconciliation is presented in Attachment SMM-3, page 4. As of June 30, 2014, there is a remaining over-recovery balance of $138,697, which the Company will continue to refund through September 30, 2014.

Q. How does the Company propose to refund or recover the residual balance at September 30, 2014?

A. Pursuant to the ISR Provision, the amount approved for recovery or refund through the O&M Reconciling Factor is subject to reconciliation. Therefore, the Company will present the final reconciliation of the balances from the FY 2013 O&M reconciliation in the FY 2015 ISR Reconciliation Filing and include the residual balance of the FY 2013 O&M reconciliation with the FY 2015 O&M Reconciliation Factor.

VI. TYPICAL BILL ANALYSIS

Q. Is the Company providing a typical bill analysis to illustrate the impact of the proposed rates on each of the Company's rate classes?

A. Yes. The typical bill analysis illustrating the monthly bill impact of the proposed rate changes for each rate class is provided in Attachment SMM-4. The impact of the proposed CapEx Reconciling Factor and the proposed O&M Reconciling Factor on a typical residential customer receiving Standard Offer Service and using 500 kWhs per month is a decrease of $0.04, or approximately 0.1%, from $86.65 to $86.61.

Q. Is the Company providing a proposed Summary of Retail Delivery Rates, Tariff No. 2095, reflecting the reconciling factors proposed in this filing?

A. Not at this time. The Company anticipates submitting a Pension and other post-employment benefits ("OPEB") Adjustment Factor ("PAF") filing, and will likely propose a PAF for effect on October 1, 2014. The Company will file a Summary of Retail Delivery Rates reflecting all rate changes proposed for October 1, 2014 in compliance with the PUC's orders in this proceeding and the PAF proceeding.

VII. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.

List of Attachments

Attachment SMM-1	FY2014 ISR Plan Annual Reconciliation Summary
Attachment SMM-2	CapEx Reconciliations and Proposed CapEx Reconciling Factors
Attachment SMM-3	O&M Reconciliations and Proposed O&M Reconciling Factor
Attachment SMM-4	Typical Bill Analysis

Attachment SMM-1

Attachment SMM-1

FY2014 ISR Plan Annual Reconciliation Summary

FY 2014 ISR Plan Annual Reconciliation Summary

Line No.		CapEx (a)	O&M (b)	Total (c)
(1)	Actual Revenue Requirement	($969,137)	$11,950,733	$10,981,596
(2)	Revenue Billed	$1,738	$12,356,847	$12,358,585
(3)	Total Over Recovery	$970,875	$406,114	$1,376,989

Line Notes:

(1) Column (a) per Attachment WRR-1, Page 1, Line (12
Column (b) per Attachment WRR-1, page 1, Line (5)
Column (c) per Attachment WRR-1, page 1, Line (13

(2) Column (a) per Attachment SMM-2, page 2, Column (b) per Attachment SMM-3, page 2

(3) Line (2) - Line (1)

Attachment SMM-2

Attachment SMM-2

CapEx Reconciliations and Proposed CapEx Reconciling Factors

Proposed CapEx Reconciling Factors
For Fiscal Year 2014 ISR Plan
For the Recovery (Refund) Period October 1, 2014 through September 30, 2015

Line No.		Total (a)	Residential A-16 / A-60 (b)	Small C&I C-06 (c)	General C&I G-02 (d)	200 kW Demand B-32 / G-32 (e)	3000 kW Demand B-62 / G-62 (f)	Lighting S-10 / S-14 (g)	Propulsion X-01 (h)
(1)	Actual FY2014 Capital Investment Revenue Requirement	($969,137)							
(2)	Total Rate Base ($000s)	$561,738	$296,490	$54,542	$82,460	$77,651	$19,545	$29,286	$1,764
(3)	Rate Base as Percentage of Total	100.00%	52.78%	9.71%	14.68%	13.82%	3.48%	5.21%	0.31%
(4)	Allocated Actual FY2014 Capital Investment Revenue Requirement	($969,137)	($511,518)	($94,099)	($142,264)	($133,967)	($33,720)	($50,526)	($3,043)
(5)	CapEx Revenue Billed	$1,738	$322	($628)	($162)	$75	$122	$2,003	$6
(6)	Total Over (Under) Recovery for FY 2014	$970,875	$511,840	$93,471	$142,102	$134,042	$33,842	$52,529	$3,049
(7)	Remaining Over (Under) For FY 2012	$25,533	$10,137	$2,346	$2,718	$11,264	($1,482)	$718	($168)
(8)	Total Over (Under) Recovery	$996,407	$521,977	$95,817	$144,819	$145,306	$32,360	$53,247	$2,881
(9)	Forecasted kWhs - October 1, 2014 through September 30, 2015	7,787,924,049	3,264,458,077	595,770,380	1,281,143,411	2,068,148,078	486,336,166	68,854,859	23,213,078
(10)	Proposed Class-specific CapEx Reconciling Factor (Credit) per kWh		($0.00015)	($0.00016)	($0.00011)	($0.00007)	($0.00006)	($0.00077)	($0.00012)

Line Notes:
(1) Column (a) per Attachment WRR-1, Page 1, Line (12)
(2) per R.I.P.U.C. 4323, Compliance Attachment 3A, (Schedule HSG-1), page 2, Line (10)
(3) Line (2) ÷ Line (2) Total Column
(4) Line (1) Total Column x Line (3)
(5) per page 2
(6) Line (5) - Line (4)
(7) per page 3
(8) Line (6) + Line (7)
(9) per Company forecasts
(10) -1 x [Line (8) ÷ Line (9)], truncated to 5 decimal places

Fiscal Year 2014 Operations & Maintenance Reconciliation
For the Period April 1, 2013 through March 31, 2014
For the Recovery/Refund Period October 1, 2014 through September 30, 2015

CapEx Revenue By Rate Class:

Line No.		Residential A-16 / A-60			Small C&I C-06			General C&I G-02			200 kW Demand B-32 / G-32		
	Month	Total Revenue (a)	CapEx Rec Factor Revenue (b)	Base Revenue (c)	Total Revenue (a)	CapEx Rec Factor Revenue (b)	Base Revenue (c)	Total Revenue (a)	CapEx Rec Factor Revenue (b)	Base Revenue (c)	Total Revenue (a)	CapEx Rec Factor Revenue (b)	Base Revenue (c)
(1)	Apr-13	($18)	$0	($18)	($3)	$0	($3)	($2,987)	($3,021)	$34	$0	$0	$0
	May-13	$32	$0	$32	($49)	$0	($49)	($3,011)	($3,016)	$5	$0	$0	$0
	Jun-13	($96)	$0	($96)	($28)	$0	($28)	($3,286)	($3,199)	($87)	$14	$0	$14
	Jul-13	$26	$0	$26	($18)	$0	($18)	($3,757)	($3,761)	$4	$0	$0	$0
	Aug-13	$67	$0	$67	($277)	$0	($277)	($3,992)	($3,992)	$0	$0	$0	$0
	Sep-13	$13	$0	$13	($19)	$0	($19)	($3,555)	($3,551)	($4)	$0	$0	$0
	Oct-13	($6,452)	($6,452)	$0	($1,113)	($1,113)	$0	($3,054)	($3,054)	$0	($1,836)	($1,836)	$0
	Nov-13	($18,782)	($19,010)	$227	($3,152)	($2,824)	($328)	($4,678)	($4,909)	$231	($4,539)	($4,602)	$62
	Dec-13	($24,245)	($24,281)	$36	($3,333)	($3,396)	$63	($5,158)	($5,144)	($14)	($4,936)	($4,937)	$2
	Jan-14	($28,309)	($28,319)	$11	($3,830)	($3,839)	$9	($5,720)	($5,717)	($3)	($5,340)	($5,347)	$7
	Feb-14	($25,050)	($25,062)	$12	($3,663)	($3,669)	$6	($5,335)	($5,359)	$24	($4,952)	($4,941)	($10)
	Mar-14	($24,415)	($24,428)	$13	($3,611)	($3,626)	$15	($5,497)	($5,145)	($353)	($4,806)	($4,806)	($0)
(2)	Apr-14	($11,784)	($11,784)	$0	($1,816)	($1,816)	$0	($2,778)	($2,778)	$0	($2,697)	($2,697)	$0
	Total	($139,014)	($139,336)	$322	($20,911)	($20,283)	($628)	($52,809)	($52,647)	($162)	($29,092)	($29,167)	$75

		3000 kW Demand B-62 / G-62			Lighting S-10 / S-14			Propulsion X-01		
	Month	Total Revenue (a)	CapEx Rec Factor Revenue (b)	Base Revenue (c)	Total Revenue (a)	CapEx Rec Factor Revenue (b)	Base Revenue (c)	Total Revenue (a)	CapEx Rec Factor Revenue (b)	Base Revenue (c)
(1)	Apr-13	$0	$0	$0	($60)	($109)	$48	$19	$19	($0)
	May-13	$0	$0	$0	$39	($86)	$125	$20	$20	$0
	Jun-13	$0	$0	$0	$37	($81)	$118	$19	$19	($0)
	Jul-13	$0	$0	$0	$37	($82)	$119	$18	$18	$0
	Aug-13	$0	$0	$0	$43	($94)	$137	$21	$21	($0)
	Sep-13	$0	$0	$0	$46	($98)	$144	$20	$20	$0
	Oct-13	($38)	($38)	$0	($252)	($276)	$25	$19	$19	$0
	Nov-13	($1,353)	($1,456)	$103	($364)	($546)	$182	($160)	($166)	$6
	Dec-13	($1,340)	($1,340)	($0)	($421)	($634)	$212	($169)	($169)	$0
	Jan-14	($1,223)	($1,243)	$20	($422)	($634)	$212	($198)	($198)	($0)
	Feb-14	($1,689)	($1,689)	$0	($382)	($574)	$193	($153)	($153)	$0
	Mar-14	($1,365)	($1,365)	($0)	($321)	($479)	$158	($161)	($161)	($0)
(2)	Apr-14	($851)	($851)	$0	$82	($246)	$328	($103)	($103)	$0
	Total	($7,861)	($7,983)	$122	($1,937)	($3,940)	$2,003	($808)	($814)	$6

Line Notes:
(1) Reflects revenue associated with consumption on and after April 1
(2) Reflects revenue associated with consumption prior to April 1

Column Notes:
(a) from monthly revenue reports
(b) per page 3 and page 4
(c) Column (a) - Column (b)

Fiscal Year 2012 CapEx Reconciliation of Over Recovery
For the Period April 1, 2011 through March 31, 2012
For the Recovery Period October 1, 2012 through September 30, 2013

Line No.		Total	Residential A-16 / A-60		Small C&I C-06		General C&I G-02		200 kW Demand B-32 / G-32	
		(a)	(b)	(c)	(b)	(c)	(b)	(c)	(b)	(c)
(1)	Beginning Over(Under) Recovery	$65,588		$10,137		$2,346		$41,706		$11,264
(2)	CapEx Reconciling Factors			$0.00000		$0.00000		($0.00003)		$0.00000
			kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue
(3)	Oct-12	($1,299)	90,409,530	$0	17,630,262	$0	41,994,021	($1,260)	66,314,539	$0
	Nov-12	($3,068)	212,308,534	$0	40,957,859	$0	98,820,356	($2,965)	157,798,682	$0
	Dec-12	($3,100)	262,483,084	$0	47,298,764	$0	99,435,080	($2,983)	160,192,871	$0
	Jan-13	($3,238)	294,661,412	$0	51,048,120	$0	103,578,144	($3,107)	165,210,789	$0
	Feb-13	($3,515)	275,974,425	$0	51,199,306	$0	113,723,829	($3,412)	176,799,557	$0
	Mar-13	($3,110)	251,101,587	$0	48,155,908	$0	100,736,603	($3,022)	161,195,965	$0
	Apr-13	($3,111)	238,458,753	$0	48,236,868	$0	100,694,568	($3,021)	161,047,030	$0
	May-13	($3,082)	211,292,853	$0	46,167,078	$0	100,548,316	($3,016)	166,200,837	$0
	Jun-13	($3,262)	230,238,986	$0	48,537,075	$0	106,643,738	($3,199)	167,208,395	$0
	Jul-13	($3,825)	337,517,102	$0	56,909,518	$0	125,380,258	($3,761)	190,635,148	$0
	Aug-13	($4,065)	366,301,718	$0	50,431,469	$0	133,079,655	($3,992)	196,520,930	$0
	Sep-13	($3,629)	278,795,091	$0	52,042,736	$0	118,358,382	($3,551)	178,701,473	$0
(4)	Oct-13	($1,699)	118,977,991	$0	24,177,757	$0	56,620,741	($1,699)	92,042,276	$0
(5)	Total	($40,055)	3,168,521,066	$0	582,792,720	$0	1,299,613,691	($38,988)	2,039,868,493	$0
(6)	Ending Over(Under) Recovery	$25,533		$10,137		$2,346		$2,718		$11,264

		3000 kW Demand B-62 / G-62		Lighting S-10 / S-14		Propulsion X-01	
		(b)	(c)	(b)	(c)	(b)	(c)
(1)	Beginning Over(Under) Recovery		($1,482)		$2,011		($394)
(2)	CapEx Reconciling Factors		$0.00000		($0.00002)		$0.00001
		kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue
(3)	Oct-12	18,989,254	$0	2,326,033	($47)	773,078	$8
	Nov-12	44,951,030	$0	6,138,253	($123)	1,953,798	$20
	Dec-12	42,917,554	$0	6,675,827	($134)	1,654,207	$17
	Jan-13	41,237,325	$0	7,504,431	($150)	1,945,270	$19
	Feb-13	49,632,967	$0	6,116,885	($122)	1,872,605	$19
	Mar-13	41,724,269	$0	5,232,817	($105)	1,692,846	$17
	Apr-13	44,101,963	$0	5,440,613	($109)	1,852,188	$19
	May-13	43,744,941	$0	4,295,980	($86)	2,017,577	$20
	Jun-13	42,826,048	$0	4,069,439	($81)	1,885,083	$19
	Jul-13	52,099,116	$0	4,093,578	($82)	1,814,922	$18
	Aug-13	53,779,015	$0	4,687,467	($94)	2,087,341	$21
	Sep-13	48,773,214	$0	4,915,985	($98)	1,970,522	$20
(4)	Oct-13	29,488,582	$0	3,152,552	($63)	1,086,108	$11
(5)	Total	554,265,278	$0	64,649,860	($1,293)	22,605,546	$226
(6)	Ending Over(Under) Recovery		($1,482)		$718		($168)

Line Notes:
(1) per R.I.P.U.C. Docket No. 4218, Attachment NR-4, page 2, line (6)
(2) per R.I.P.U.C. Docket No. 4218, Attachment NR-4, page 2, line (8)
(3) prorated for usage on and after October 1st
(4) prorated for usage prior to October 1st
(5) sum of kWhs & revenue
(6) Line (1) + Line (5)

Column Notes:
(a) sum of Column (b) from each rate
(b) from Company revenue report
(c) Column (b) x CapEx Reconciling Factor

Fiscal Year 2013 CapEx Reconciliation of Over Recovery
For the Period April 1, 2012 through March 31, 2013
For the Recovery Period October 1, 2013 through September 30, 2014

Line No.		Total	Residential A-16 / A-60		Small C&I C-06		General C&I G-02		200 kW Demand B-32 / G-32	
		(a)	(b)	(c)	(b)	(c)	(b)	(c)	(b)	(c)
(1)	Beginning Over(Under) Recovery	$505,592		$301,683		$39,592		$70,113		$62,660
(2)	CapEx Reconciling Factors			($0.00009)		($0.00007)		($0.00005)		($0.00003)
			kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue
(3)	Oct-13	($11,000)	prorated	($6,452)	prorated	($1,113)	prorated	($1,356)	prorated	($1,836)
	Nov-13	($33,513)	211,219,303	($19,010)	40,348,085	($2,824)	98,176,139	($4,909)	153,385,786	($4,602)
	Dec-13	($39,902)	269,792,281	($24,281)	48,512,343	($3,396)	102,889,615	($5,144)	164,580,919	($4,937)
	Jan-14	($45,297)	314,659,652	($28,319)	54,844,919	($3,839)	114,335,036	($5,717)	178,237,603	($5,347)
	Feb-14	($41,448)	278,468,067	($25,062)	52,412,974	($3,669)	107,171,540	($5,359)	164,708,297	($4,941)
	Mar-14	($40,011)	271,422,299	($24,428)	51,805,939	($3,626)	102,896,022	($5,145)	160,211,645	($4,806)
	Apr-14	($36,018)	232,598,207	($20,934)	46,077,430	($3,225)	98,705,038	($4,935)	159,699,323	($4,791)
	May-14	($34,881)	216,615,942	($19,495)	45,091,382	($3,156)	103,435,782	($5,172)	166,687,293	($5,001)
	Jun-14	($33,456)	206,916,220	($18,622)	44,351,895	($3,105)	101,229,153	($5,061)	161,823,775	($4,855)
	Jul-14	$0	-	$0	-	$0	-	$0	-	$0
	Aug-14	$0	-	$0	-	$0	-	$0	-	$0
	Sep-14	$0	-	$0	-	$0	-	$0	-	$0
(4)	Oct-14	$0	-	$0	-	$0	-	$0	-	$0
(5)	Total	($315,526)		($186,604)		($27,954)		($42,798)		($41,116)
(6)	Ending Over(Under) Recovery	$190,066		$115,079		$11,638		$27,316		$21,544

		3000 kW Demand B-62 / G-62		Lighting S-10 / S-14		Propulsion X-01	
		(b)	(c)	(b)	(c)	(b)	(c)
(1)	Beginning Over(Under) Recovery		$22,937		$6,332		$2,275
(2)	CapEx Reconciling Factors		($0.00003)		($0.00009)		($0.00009)
		kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue	kWhs	CapEx Reconciling Factor Revenue
(3)	Oct-13	prorated	($38)	prorated	($213)	prorated	$8
	Nov-13	48,536,327	($1,456)	6,064,161	($546)	1,846,398	($166)
	Dec-13	44,672,551	($1,340)	7,039,472	($634)	1,881,226	($169)
	Jan-14	41,426,522	($1,243)	7,048,986	($634)	2,195,741	($198)
	Feb-14	56,308,347	($1,689)	6,382,132	($574)	1,701,483	($153)
	Mar-14	45,511,176	($1,365)	5,322,165	($479)	1,786,214	($161)
	Apr-14	50,414,209	($1,512)	4,859,305	($437)	2,027,668	($182)
	May-14	48,501,849	($1,455)	4,679,271	($421)	2,009,991	($181)
	Jun-14	43,165,460	($1,295)	3,605,805	($325)	2,150,872	($194)
	Jul-14	-	$0	-	$0	-	$0
	Aug-14	-	$0	-	$0	-	$0
	Sep-14	-	$0	-	$0	-	$0
(4)	Oct-14	-	$0	-	$0	-	$0
(5)	Total	378,536,441	($11,394)	45,001,297	($4,263)	15,599,593	($1,396)
(6)	Ending Over(Under) Recovery		$11,543		$2,068		$879

Line Notes:
(1) per R.I.P.U.C. Docket No. 4307, Attachment NR-4, page 1, line (6)
(2) per R.I.P.U.C. Docket No. 4307, Attachment NR-4, page 1, line (8)
(3) prorated for usage on and after October 1st
(4) prorated for usage prior to October 1st
(5) sum of kWhs & revenue
(6) Line (1) + Line (5)

Column Notes:
(a) sum of Column (b) from each rate
(b) from Company revenue report
(c) Column (b) x CapEx Reconciling Factor

Attachment SMM-3

Attachment SMM-3

O&M Reconciliations and Proposed O&M Reconciling Factor

Fiscal Year 2014 Operation & Maintenance Reconciliation and Proposed Factor
Reconciliation of O&M Revenue and Actual O&M Revenue Requirement
For Fiscal Year 2014 ISR Plan
For the Recovery (Refund) Period October 1, 2014 through September 30, 2015

Line No.		
(1)	Actual FY 2014 O&M Revenue Requirement	$11,950,733
(2)	O&M Revenue Billed	$12,356,847
(3)	Total Over (Under) Recovery for FY 2014	$406,114
(4)	Remaining Over (Under) For FY 2012	($4,399)
(5)	Total Over (Under) Recovery	$401,715
(6)	Forecasted kWhs - October 1, 2014 through September 30, 2015	7,787,924,049
(7)	Proposed O&M Reconciling Factor (Credit) per kWh	($0.00005)

Line Notes:
(1) per page 2
(2) per Attachment WRR-1, page 1, Line (5)
(3) Line (2) - Line (1)
(4) per page 3 Line (4)
(5) Line (3) + Line (4)
(6) per Company forecast
(7) -1 x [Line (5) ÷ Line (6)], truncated to 5 decimal places

Fiscal Year 2014 Operations & Maintenance Reconciliation
For the Period April 1, 2013 through March 31, 2014
For the Recovery/Refund Period October 1, 2014 through September 30, 2015

O&M Factor Revenue:

Line No.	Month	O&M Revenue (a)	Prior Period Reconciliation Factor Revenue (b)	Base O&M Revenue (c)
(1)	Apr-13	$368,887	$5,039	$363,849
	May-13	$896,968	$11,485	$885,483
	Jun-13	$946,763	$12,028	$934,735
	Jul-13	$1,228,829	$15,369	$1,213,460
	Aug-13	$1,293,410	$16,138	$1,277,272
	Sep-13	$1,092,055	$13,671	$1,078,384
	Oct-13	$893,344	($3,277)	$896,621
	Nov-13	$867,439	($22,383)	$889,822
	Dec-13	$1,019,171	($25,575)	$1,044,746
	Jan-14	$1,145,352	($28,510)	$1,173,862
	Feb-14	$1,043,280	($26,686)	$1,069,966
	Mar-14	$1,010,194	($25,558)	$1,035,752
(2)	Apr-14	$479,513	($13,383)	$492,896
	Total	$12,285,205	($71,642)	$12,356,847

Line Notes:
(1) Reflects kWhs consumed on and after April 1
(2) Reflects kWhs consumed prior to April 1

Column Notes:
(a) from monthly revenue reports
(b) per page 3 and page 4
(c) Column (a) - Column (b)

Fiscal Year 2012 O&M Reconciliation of Under Recovery
For the Period April 1, 2012 through March 31, 2012
For the Recovery Period October 1, 2012 through September 30, 2013

Line No.		Total	
(1)	Over (Under) Recovery	$ (159,045)	
(2)	O&M Reconciling Factor	$0.00002	
		Total kWhs	Total Revenue
		(a)	(b)
	Oct-12	238,436,718	$4,769
	Nov-12	562,928,512	$11,259
	Dec-12	620,657,387	$12,413
	Jan-13	665,185,491	$13,304
	Feb-13	675,319,574	$13,506
	Mar-13	609,839,995	$12,197
	Apr-13	599,831,983	$11,997
	May-13	574,267,582	$11,485
	Jun-13	601,408,764	$12,028
	Jul-13	768,449,642	$15,369
	Aug-13	806,887,595	$16,138
	Sep-13	683,557,403	$13,671
	Oct-13	325,546,007	$6,511
(3)	Total	7,732,316,653	$154,646
(4)	Over (Under) Recovery		$ (4,399)

Line Descriptions:
(1) per R.I.P.U.C. Docket No. 4218, Attachment NR-5, page 1, line (3)
(2) per R.I.P.U.C. Docket No. 4218, Attachment NR-5, page 1, line (5)
(3) sum of kWhs & revenue
(4) Line (1) + Line (3)

Column Descriptions:
(a) per Company Records
(b) Line (2) x Column (a)

Fiscal Year 2013 O&M Reconciliation of Over Recovery
For the Period April 1, 2012 through March 31, 2013
For the Recovery Period October 1, 2013 through September 30, 2014

Line No.		Total	
(1)	Over (Under) Recovery	$346,982	
(2)	O&M Reconciling Factor	($0.00004)	
		Total kWhs	Total Revenue
		(a)	(b)
	Oct-13	244,686,971	($9,787)
	Nov-13	559,576,199	($22,383)
	Dec-13	639,368,407	($25,575)
	Jan-14	712,748,459	($28,510)
	Feb-14	667,152,840	($26,686)
	Mar-14	638,955,460	($25,558)
	Apr-14	594,381,180	($23,775)
	May-14	587,021,510	($23,481)
	Jun-14	563,243,180	($22,530)
	Jul-14	-	$0
	Aug-14	-	$0
	Sep-14	-	$0
	Oct-14	-	$0
(3)	Total	5,207,134,206	($208,285)
(4)	Over (Under) Recovery		$138,697

Line Descriptions:
(1) per R.I.P.U.C. Docket No. 4307, Attachment NR-5-Revised, page 1, line (3)
(2) per R.I.P.U.C. Docket No. 4307, Attachment NR-5-Revised, page 1, line (5)
(3) sum of kWhs & revenue
(4) Line (1) + Line (3)

Column Descriptions:
(a) per Company Records
(b) Line (2) x Column (a)

Attachment SMM-4

Typical Bill Analysis

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to A-16 Rate Customers

Monthly kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total	Percentage of Customers
150	$30.17	$13.06	$17.11	$30.16	$13.06	$17.10	($0.01)	0.0%	13.7%
300	$54.38	$26.13	$28.25	$54.36	$26.13	$28.23	($0.02)	0.0%	17.5%
400	$70.51	$34.83	$35.68	$70.48	$34.83	$35.65	($0.03)	0.0%	11.8%
500	$86.65	$43.54	$43.11	$86.61	$43.54	$43.07	($0.04)	0.0%	10.8%
600	$102.78	$52.24	$50.54	$102.73	$52.24	$50.49	($0.05)	0.0%	9.4%
700	$118.92	$60.95	$57.97	$118.86	$60.95	$57.91	($0.06)	-0.1%	7.7%
1,000	$167.32	$87.07	$80.25	$167.25	$87.07	$80.18	($0.07)	0.0%	15.0%
2,000	$328.68	$174.15	$154.53	$328.54	$174.15	$154.39	($0.14)	0.0%	14.1%

Present Rates

Customer Charge		$5.00
LIHEAP Charge		$0.73
Transmission Energy Charge	kWh x	$0.02221
Distribution Energy Charge (1)	kWh x	$0.03834
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08359

Proposed Rates

Customer Charge		$5.00
LIHEAP Charge		$0.73
Transmission Energy Charge	kWh x	$0.02221
Distribution Energy Charge (2)	kWh x	$0.03827
Proposed Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08359

Note (1): includes the current CapEx Reconciling of (0.009¢)/kWh and the current O&M Reconciling of (0.004¢)/kWh

Note (2): includes the proposed CapEx Reconciling of (0.015¢)/kWh and the proposed O&M Reconciling of (0.005¢)/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to A-60 Rate Customers

Monthly kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total	Percentage of Customers
150	$22.86	$13.06	$9.80	$22.85	$13.06	$9.79	($0.01)	0.0%	10.7%
300	$44.96	$26.12	$18.84	$44.93	$26.12	$18.81	($0.03)	-0.1%	23.2%
400	$59.69	$34.83	$24.86	$59.66	$34.83	$24.83	($0.03)	-0.1%	14.9%
500	$74.43	$43.54	$30.89	$74.39	$43.54	$30.85	($0.04)	-0.1%	12.2%
600	$89.15	$52.24	$36.91	$89.11	$52.24	$36.87	($0.04)	0.0%	9.6%
700	$103.89	$60.95	$42.94	$103.83	$60.95	$42.88	($0.06)	-0.1%	7.3%
1,000	$148.08	$87.07	$61.01	$148.01	$87.07	$60.94	($0.07)	0.0%	12.3%
2,000	$295.41	$174.15	$121.26	$295.26	$174.15	$121.11	($0.15)	-0.1%	9.8%

Present Rates

Customer Charge		$0.00
LIHEAP Charge		$0.73
Transmission Energy Charge	kWh x	$0.02221
Distribution Energy Charge (1)	kWh x	$0.02487
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08359

Proposed Rates

Customer Charge		$0.00
LIHEAP Charge		$0.73
Transmission Energy Charge	kWh x	$0.02221
Distribution Energy Charge (2)	kWh x	$0.02480
Proposed Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.08359

Note (1): includes the current CapEx Reconciling of (0.009¢)/kWh and the current O&M Reconciling of (0.004¢)/kWh

Note (2): includes the proposed CapEx Reconciling of (0.015¢)/kWh and the proposed O&M Reconciling of (0.005¢)/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to C-06 Rate Customers

Monthly kWh	Present Rates Total	Present Rates Standard Offer	Present Rates Delivery	Proposed Rates Total	Proposed Rates Standard Offer	Proposed Rates Delivery	Increase/(Decrease) Amount	Increase/(Decrease) % of Total	Percentage of Customers
250	$52.33	$24.17	$28.16	$52.31	$24.17	$28.14	($0.02)	0.0%	35.2%
500	$93.49	$48.34	$45.15	$93.43	$48.34	$45.09	($0.06)	-0.1%	17.0%
1,000	$175.79	$96.68	$79.11	$175.69	$96.68	$79.01	($0.10)	-0.1%	19.0%
1,500	$258.10	$145.02	$113.08	$257.95	$145.02	$112.93	($0.15)	-0.1%	9.8%
2,000	$340.40	$193.35	$147.05	$340.19	$193.35	$146.84	($0.21)	-0.1%	19.1%

<u>Present Rates</u>

Customer Charge		$10.00
LIHEAP Charge		$0.73
Transmission Energy Charge	kWh x	$0.02003
Distribution Energy Charge (1)	kWh x	$0.03443
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.09281

<u>Proposed Rates</u>

Customer Charge		$10.00
LIHEAP Charge		$0.73
Transmission Energy Charge	kWh x	$0.02003
Distribution Energy Charge (2)	kWh x	$0.03433
Proposed Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.09281

Note (1): includes the current CapEx Reconciling of (0.007¢)/kWh and the current O&M Reconciling of (0.004¢)/kWh

Note (2): includes the proposed CapEx Reconciling of (0.016¢)/kWh and the proposed O&M Reconciling of (0.005¢)/ kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-02 Rate Customers

Hours Use: 200

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
20	4,000	$743.47	$386.71	$356.76	$743.18	$386.71	$356.47	($0.29)	0.0%
50	10,000	$1,723.47	$966.77	$756.70	$1,722.74	$966.77	$755.97	($0.73)	0.0%
100	20,000	$3,356.80	$1,933.54	$1,423.26	$3,355.34	$1,933.54	$1,421.80	($1.46)	0.0%
150	30,000	$4,990.13	$2,900.31	$2,089.82	$4,987.95	$2,900.31	$2,087.64	($2.18)	0.0%

Present Rates

Customer Charge		$135.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.00768
Distribution Demand Charge-xcs 10 kW	kW x	$4.92
Distribution Energy Charge (1)	kWh x	$0.00585
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.09281

Proposed Rates

Customer Charge		$135.00
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.00768
Distribution Demand Charge-xcs 10 kW	kW x	$4.92
Distribution Energy Charge (2)	kWh x	$0.00578
Proposed Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.09281

Note (1): includes the current CapEx Reconciling of (0.005¢)/kWh and the current O&M Reconciling of (0.004¢)/kWh

Note (2): includes the proposed CapEx Reconciling of (0.011¢)/kWh and the proposed O&M Reconciling of (0.005¢)/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-02 Rate Customers

Hours Use: 300

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
20	6,000	$987.42	$580.06	$407.36	$986.99	$580.06	$406.93	($0.43)	0.0%
50	15,000	$2,333.37	$1,450.16	$883.21	$2,332.27	$1,450.16	$882.11	($1.10)	0.0%
100	30,000	$4,576.59	$2,900.31	$1,676.28	$4,574.40	$2,900.31	$1,674.09	($2.19)	0.0%
150	45,000	$6,819.82	$4,350.47	$2,469.35	$6,816.54	$4,350.47	$2,466.07	($3.28)	0.0%

Present Rates

Customer Charge		$135.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.00768
Distribution Demand Charge-xcs 10 kW	kW x	$4.92
Distribution Energy Charge (1)	kWh x	$0.00585
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.09281

Proposed Rates

Customer Charge		$135.00
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.00768
Distribution Demand Charge-xcs 10 kW	kW x	$4.92
Distribution Energy Charge (2)	kWh x	$0.00578
Proposed Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.09281

Note (1): includes the current CapEx Reconciling of (0.005¢)/kWh and the current O&M Reconciling of (0.004¢)/kWh

Note (2): includes the proposed CapEx Reconciling of (0.011¢)/kWh and the proposed O&M Reconciling of (0.005¢)/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-02 Rate Customers

Hours Use: 400

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
20	8,000	$1,231.39	$773.42	$457.97	$1,230.81	$773.42	$457.39	($0.58)	0.0%
50	20,000	$2,943.26	$1,933.54	$1,009.72	$2,941.80	$1,933.54	$1,008.26	($1.46)	0.0%
100	40,000	$5,796.38	$3,867.08	$1,929.30	$5,793.47	$3,867.08	$1,926.39	($2.91)	-0.1%
150	60,000	$8,649.52	$5,800.63	$2,848.89	$8,645.14	$5,800.63	$2,844.51	($4.38)	-0.1%

<u>Present Rates</u>

Customer Charge		$135.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.00768
Distribution Demand Charge-xcs 10 kW	kW x	$4.92
Distribution Energy Charge (1)	kWh x	$0.00585
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.09281

<u>Proposed Rates</u>

Customer Charge		$135.00
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.00768
Distribution Demand Charge-xcs 10 kW	kW x	$4.92
Distribution Energy Charge (2)	kWh x	$0.00578
Proposed Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.09281

Note (1): includes the current CapEx Reconciling of (0.005¢)/kWh and the current O&M Reconciling of (0.004¢)/kWh

Note (2): includes the proposed CapEx Reconciling of (0.011¢)/kWh and the proposed O&M Reconciling of (0.005¢)/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-02 Rate Customers

Hours Use: 500

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
20	10,000	$1,475.34	$966.77	$508.57	$1,474.61	$966.77	$507.84	($0.73)	0.0%
50	25,000	$3,553.16	$2,416.93	$1,136.23	$3,551.34	$2,416.93	$1,134.41	($1.82)	-0.1%
100	50,000	$7,016.17	$4,833.85	$2,182.32	$7,012.53	$4,833.85	$2,178.68	($3.64)	-0.1%
150	75,000	$10,479.20	$7,250.78	$3,228.42	$10,473.73	$7,250.78	$3,222.95	($5.47)	-0.1%

Present Rates

Customer Charge		$135.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.00768
Distribution Demand Charge-xcs 10 kW	kW x	$4.92
Distribution Energy Charge (1)	kWh x	$0.00585
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.09281

Proposed Rates

Customer Charge		$135.00
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.00768
Distribution Demand Charge-xcs 10 kW	kW x	$4.92
Distribution Energy Charge (2)	kWh x	$0.00578
Proposed Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.09281

Note (1): includes the current CapEx Reconciling of (0.005¢)/kWh and the current O&M Reconciling of (0.004¢)/kWh

Note (2): includes the proposed CapEx Reconciling of (0.011¢)/kWh and the proposed O&M Reconciling of (0.005¢)/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-02 Rate Customers

Hours Use: 600

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
20	12,000	$1,719.31	$1,160.13	$559.18	$1,718.43	$1,160.13	$558.30	($0.88)	-0.1%
50	30,000	$4,163.05	$2,900.31	$1,262.74	$4,160.86	$2,900.31	$1,260.55	($2.19)	-0.1%
100	60,000	$8,235.97	$5,800.63	$2,435.34	$8,231.60	$5,800.63	$2,430.97	($4.37)	-0.1%
150	90,000	$12,308.89	$8,700.94	$3,607.95	$12,302.33	$8,700.94	$3,601.39	($6.56)	-0.1%

<u>Present Rates</u>

Customer Charge		$135.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.00768
Distribution Demand Charge-xcs 10 kW	kW x	$4.92
Distribution Energy Charge (1)	kWh x	$0.00585
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.09281

<u>Proposed Rates</u>

Customer Charge		$135.00
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.00768
Distribution Demand Charge-xcs 10 kW	kW x	$4.92
Distribution Energy Charge (2)	kWh x	$0.00578
Proposed Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4.00%
Standard Offer Charge	kWh x	$0.09281

Note (1): includes the current CapEx Reconciling of (0.005¢)/kWh and the current O&M Reconciling of (0.004¢)/kWh

Note (2): includes the proposed CapEx Reconciling of (0.011¢)/kWh and the proposed O&M Reconciling of (0.005¢)/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-32 Rate Customers

Hours Use: 200

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	40,000	$5,925.55	$3,327.50	$2,598.05	$5,923.47	$3,327.50	$2,595.97	($2.08)	0.0%
750	150,000	$22,015.35	$12,478.13	$9,537.22	$22,007.54	$12,478.13	$9,529.41	($7.81)	0.0%
1,000	200,000	$29,328.89	$16,637.50	$12,691.39	$29,318.47	$16,637.50	$12,680.97	($10.42)	0.0%
1,500	300,000	$43,955.97	$24,956.25	$18,999.72	$43,940.34	$24,956.25	$18,984.09	($15.63)	0.0%
2,500	500,000	$73,210.14	$41,593.75	$31,616.39	$73,184.09	$41,593.75	$31,590.34	($26.05)	0.0%

<u>Present Rates</u>

Customer Charge		$825.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00774
Distribution Demand Charge - > 200 kW	kW x	$3.77
Distribution Energy Charge (1)	kWh x	$0.00621
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07986

<u>Proposed Rates</u>

Customer Charge		$825.00
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00774
Distribution Demand Charge - > 200 kW	kW x	$3.77
Distribution Energy Charge (2)	kWh x	$0.00616
Proposed Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kW x	$0.00039
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07986

Note (1): includes the current CapEx Reconciling of (0.003¢)/kWh and the current O&M Reconciling of (0.004¢)/kWh

Note (2): includes the proposed CapEx Reconciling of (0.007¢)/kWh and the proposed O&M Reconciling of (0.005¢)/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-32 Rate Customers

Hours Use: 300

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	60,000	$8,104.09	$4,991.25	$3,112.84	$8,100.97	$4,991.25	$3,109.72	($3.12)	0.0%
750	225,000	$30,184.88	$18,717.19	$11,467.69	$30,173.16	$18,717.19	$11,455.97	($11.72)	0.0%
1,000	300,000	$40,221.59	$24,956.25	$15,265.34	$40,205.97	$24,956.25	$15,249.72	($15.62)	0.0%
1,500	450,000	$60,295.04	$37,434.38	$22,860.66	$60,271.60	$37,434.38	$22,837.22	($23.44)	0.0%
2,500	750,000	$100,441.91	$62,390.63	$38,051.28	$100,402.85	$62,390.63	$38,012.22	($39.06)	0.0%

Present Rates

Customer Charge		$825.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00774
Distribution Demand Charge - > 200 kW	kW x	$3.77
Distribution Energy Charge (1)	kWh x	$0.00621
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07986

Proposed Rates

Customer Charge		$825.00
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00774
Distribution Demand Charge - > 200 kW	kW x	$3.77
Distribution Energy Charge (2)	kWh x	$0.00616
Proposed Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kW x	$0.00039
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07986

Note (1): includes the current CapEx Reconciling of (0.003¢)/kWh and the current O&M Reconciling of (0.004¢)/kWh

Note (2): includes the proposed CapEx Reconciling of (0.007¢)/kWh and the proposed O&M Reconciling of (0.005¢)/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-32 Rate Customers

Hours Use: 400

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	80,000	$10,282.64	$6,655.00	$3,627.64	$10,278.47	$6,655.00	$3,623.47	($4.17)	0.0%
750	300,000	$38,354.41	$24,956.25	$13,398.16	$38,338.78	$24,956.25	$13,382.53	($15.63)	0.0%
1,000	400,000	$51,114.30	$33,275.00	$17,839.30	$51,093.47	$33,275.00	$17,818.47	($20.83)	0.0%
1,500	600,000	$76,634.09	$49,912.50	$26,721.59	$76,602.84	$49,912.50	$26,690.34	($31.25)	0.0%
2,500	1,000,000	$127,673.68	$83,187.50	$44,486.18	$127,621.59	$83,187.50	$44,434.09	($52.09)	0.0%

Present Rates

Customer Charge		$825.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00774
Distribution Demand Charge - > 200 kW	kW x	$3.77
Distribution Energy Charge (1)	kWh x	$0.00621
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07986

Proposed Rates

Customer Charge		$825.00
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00774
Distribution Demand Charge - > 200 kW	kW x	$3.77
Distribution Energy Charge (2)	kWh x	$0.00616
Proposed Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kW x	$0.00039
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07986

Note (1): includes the current CapEx Reconciling of (0.003¢)/kWh and the current O&M Reconciling of (0.004¢)/kWh

Note (2): includes the proposed CapEx Reconciling of (0.007¢)/kWh and the proposed O&M Reconciling of (0.005¢)/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-32 Rate Customers

Hours Use: 500

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	100,000	$12,461.18	$8,318.75	$4,142.43	$12,455.97	$8,318.75	$4,137.22	($5.21)	0.0%
750	375,000	$46,523.94	$31,195.31	$15,328.63	$46,504.40	$31,195.31	$15,309.09	($19.54)	0.0%
1,000	500,000	$62,007.01	$41,593.75	$20,413.26	$61,980.97	$41,593.75	$20,387.22	($26.04)	0.0%
1,500	750,000	$92,973.16	$62,390.63	$30,582.53	$92,934.10	$62,390.63	$30,543.47	($39.06)	0.0%
2,500	1,250,000	$154,905.45	$103,984.38	$50,921.07	$154,840.35	$103,984.38	$50,855.97	($65.10)	0.0%

Present Rates

Customer Charge		$825.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00774
Distribution Demand Charge - > 200 kW	kW x	$3.77
Distribution Energy Charge (1)	kWh x	$0.00621
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07986

Proposed Rates

Customer Charge		$825.00
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00774
Distribution Demand Charge - > 200 kW	kW x	$3.77
Distribution Energy Charge (2)	kWh x	$0.00616
Proposed Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kW x	$0.00039
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07986

Note (1): includes the current CapEx Reconciling of (0.003¢)/kWh and the current O&M Reconciling of (0.004¢)/kWh

Note (2): includes the proposed CapEx Reconciling of (0.007¢)/kWh and the proposed O&M Reconciling of (0.005¢)/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-32 Rate Customers

Hours Use: 600

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
200	120,000	$14,639.72	$9,982.50	$4,657.22	$14,633.47	$9,982.50	$4,650.97	($6.25)	0.0%
750	450,000	$54,693.47	$37,434.38	$17,259.09	$54,670.04	$37,434.38	$17,235.66	($23.43)	0.0%
1,000	600,000	$72,899.72	$49,912.50	$22,987.22	$72,868.47	$49,912.50	$22,955.97	($31.25)	0.0%
1,500	900,000	$109,312.22	$74,868.75	$34,443.47	$109,265.34	$74,868.75	$34,396.59	($46.88)	0.0%
2,500	1,500,000	$182,137.22	$124,781.25	$57,355.97	$182,059.09	$124,781.25	$57,277.84	($78.13)	0.0%

<u>Present Rates</u>

Customer Charge		$825.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00774
Distribution Demand Charge - > 200 kW	kW x	$3.77
Distribution Energy Charge (1)	kWh x	$0.00621
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07986

<u>Proposed Rates</u>

Customer Charge		$825.00
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.40
Transmission Energy Charge	kWh x	$0.00774
Distribution Demand Charge - > 200 kW	kW x	$3.77
Distribution Energy Charge (2)	kWh x	$0.00616
Proposed Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kW x	$0.00039
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07986

Note (1): includes the current CapEx Reconciling of (0.003¢)/kWh and the current O&M Reconciling of (0.004¢)/kWh

Note (2): includes the proposed CapEx Reconciling of (0.007¢)/kWh and the proposed O&M Reconciling of (0.005¢)/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-62 Rate Customers

Hours Use: 200

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
3,000	600,000	$100,859.09	$49,912.50	$50,946.59	$100,834.09	$49,912.50	$50,921.59	($25.00)	0.0%
5,000	1,000,000	$156,292.43	$83,187.50	$73,104.93	$156,250.76	$83,187.50	$73,063.26	($41.67)	0.0%
7,500	1,500,000	$225,584.09	$124,781.25	$100,802.84	$225,521.59	$124,781.25	$100,740.34	($62.50)	0.0%
10,000	2,000,000	$294,875.76	$166,375.00	$128,500.76	$294,792.43	$166,375.00	$128,417.43	($83.33)	0.0%
20,000	4,000,000	$572,042.43	$332,750.00	$239,292.43	$571,875.76	$332,750.00	$239,125.76	($166.67)	0.0%

Present Rates

Customer Charge		$17,000.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.01070
Distribution Demand Charge	kW x	$3.34
Distribution Energy Charge (1)	kWh x	($0.00008)
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07986

Proposed Rates

Customer Charge		$17,000.00
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.01070
Distribution Demand Charge	kW x	$3.34
Distribution Energy Charge (2)	kWh x	($0.00012)
Proposed Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kW x	$0.00039
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07986

Note (1): includes the current CapEx Reconciling of (0.003¢)/kWh and the current O&M Reconciling of (0.004¢)kWh

Note (2): includes the proposed CapEx Reconciling of (0.006¢)/kWh and the proposed O&M Reconciling of (0.005¢)/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-62 Rate Customers

Hours Use: 300

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
3,000	900,000	$132,496.59	$74,868.75	$57,627.84	$132,459.09	$74,868.75	$57,590.34	($37.50)	0.0%
5,000	1,500,000	$209,021.59	$124,781.25	$84,240.34	$208,959.09	$124,781.25	$84,177.84	($62.50)	0.0%
7,500	2,250,000	$304,677.85	$187,171.88	$117,505.97	$304,584.10	$187,171.88	$117,412.22	($93.75)	0.0%
10,000	3,000,000	$400,334.09	$249,562.50	$150,771.59	$400,209.09	$249,562.50	$150,646.59	($125.00)	0.0%
20,000	6,000,000	$782,959.09	$499,125.00	$283,834.09	$782,709.09	$499,125.00	$283,584.09	($250.00)	0.0%

<u>Present Rates</u>

Customer Charge		$17,000.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.01070
Distribution Demand Charge	kW x	$3.34
Distribution Energy Charge (1)	kWh x	($0.00008)
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07986

<u>Proposed Rates</u>

Customer Charge		$17,000.00
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.01070
Distribution Demand Charge	kW x	$3.34
Distribution Energy Charge (2)	kWh x	($0.00012)
Proposed Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kW x	$0.00039
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07986

Note (1): includes the current CapEx Reconciling of (0.003¢)/kWh and the current O&M Reconciling of (0.004¢)kWh

Note (2): includes the proposed CapEx Reconciling of (0.006¢)/kWh and the proposed O&M Reconciling of (0.005¢)/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-62 Rate Customers

Hours Use: 400

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
3,000	1,200,000	$164,134.09	$99,825.00	$64,309.09	$164,084.09	$99,825.00	$64,259.09	($50.00)	0.0%
5,000	2,000,000	$261,750.76	$166,375.00	$95,375.76	$261,667.43	$166,375.00	$95,292.43	($83.33)	0.0%
7,500	3,000,000	$383,771.59	$249,562.50	$134,209.09	$383,646.59	$249,562.50	$134,084.09	($125.00)	0.0%
10,000	4,000,000	$505,792.43	$332,750.00	$173,042.43	$505,625.76	$332,750.00	$172,875.76	($166.67)	0.0%
20,000	8,000,000	$993,875.76	$665,500.00	$328,375.76	$993,542.43	$665,500.00	$328,042.43	($333.33)	0.0%

<u>Present Rates</u>

Customer Charge		$17,000.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.01070
Distribution Demand Charge	kW x	$3.34
Distribution Energy Charge (1)	kWh x	($0.00008)
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07986

<u>Proposed Rates</u>

Customer Charge		$17,000.00
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.01070
Distribution Demand Charge	kW x	$3.34
Distribution Energy Charge (2)	kWh x	($0.00012)
Proposed Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kW x	$0.00039
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07986

Note (1): includes the current CapEx Reconciling of (0.003¢)/kWh and the current O&M Reconciling of (0.004¢)kWh

Note (2): includes the proposed CapEx Reconciling of (0.006¢)/kWh and the proposed O&M Reconciling of (0.005¢)/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-62 Rate Customers

Hours Use: 500

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
3,000	1,500,000	$195,771.59	$124,781.25	$70,990.34	$195,709.09	$124,781.25	$70,927.84	($62.50)	0.0%
5,000	2,500,000	$314,479.93	$207,968.75	$106,511.18	$314,375.76	$207,968.75	$106,407.01	($104.17)	0.0%
7,500	3,750,000	$462,865.35	$311,953.13	$150,912.22	$462,709.10	$311,953.13	$150,755.97	($156.25)	0.0%
10,000	5,000,000	$611,250.76	$415,937.50	$195,313.26	$611,042.43	$415,937.50	$195,104.93	($208.33)	0.0%
20,000	10,000,000	$1,204,792.43	$831,875.00	$372,917.43	$1,204,375.76	$831,875.00	$372,500.76	($416.67)	0.0%

Present Rates

Customer Charge		$17,000.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.01070
Distribution Demand Charge	kW x	$3.34
Distribution Energy Charge (1)	kWh x	($0.00008)
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07986

Proposed Rates

Customer Charge		$17,000.00
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.01070
Distribution Demand Charge	kW x	$3.34
Distribution Energy Charge (2)	kWh x	($0.00012)
Proposed Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kW x	$0.00039
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07986

Note (1): includes the current CapEx Reconciling of (0.003¢)/kWh and the current O&M Reconciling of (0.004¢)kWh

Note (2): includes the proposed CapEx Reconciling of (0.006¢)/kWh and the proposed O&M Reconciling of (0.005¢)/kWh

Calculation of Monthly Typical Bill
Total Bill Impact of Proposed
Rates Applicable to G-62 Rate Customers

Hours Use: 600

Monthly Power		Present Rates			Proposed Rates			Increase/(Decrease)	
kW	kWh	Total	Standard Offer	Delivery	Total	Standard Offer	Delivery	Amount	% of Total
3,000	1,800,000	$227,409.09	$149,737.50	$77,671.59	$227,334.09	$149,737.50	$77,596.59	($75.00)	0.0%
5,000	3,000,000	$367,209.09	$249,562.50	$117,646.59	$367,084.09	$249,562.50	$117,521.59	($125.00)	0.0%
7,500	4,500,000	$541,959.09	$374,343.75	$167,615.34	$541,771.59	$374,343.75	$167,427.84	($187.50)	0.0%
10,000	6,000,000	$716,709.09	$499,125.00	$217,584.09	$716,459.09	$499,125.00	$217,334.09	($250.00)	0.0%
20,000	12,000,000	$1,415,709.09	$998,250.00	$417,459.09	$1,415,209.09	$998,250.00	$416,959.09	($500.00)	0.0%

<u>Present Rates</u>

Customer Charge		$17,000.00
LIHEAP Charge		$0.73
Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.01070
Distribution Demand Charge	kW x	$3.34
Distribution Energy Charge (1)	kWh x	($0.00008)
Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kWh x	$0.00039
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07986

<u>Proposed Rates</u>

Customer Charge		$17,000.00
LIHEAP Charge		$0.73
Proposed Transmission Demand Charge	kW x	$3.02
Transmission Energy Charge	kWh x	$0.01070
Distribution Demand Charge	kW x	$3.34
Distribution Energy Charge (2)	kWh x	($0.00012)
Proposed Transition Energy Charge	kWh x	$0.00096
Energy Efficiency Program Charge	kWh x	$0.00941
Renewable Energy Distribution Charge	kW x	$0.00039
Gross Earnings Tax		4%
Standard Offer Charge	kWh x	$0.07986

Note (1): includes the current CapEx Reconciling of (0.003¢)/kWh and the current O&M Reconciling of (0.004¢)kWh

Note (2): includes the proposed CapEx Reconciling of (0.006¢)/kWh and the proposed O&M Reconciling of (0.005¢)/kWh