Division 1-16

Request:

Provide a copy of the Company's annual report filed with the Commission separately for each of the years 2012, 2013, 2014, 2015, and 2016.

Response:

The Company's annual report to the Public Utilities Commission is identical to the annual FERC Form 1 filing. Please refer to the Company's response to Division 1-15 for the FERC Form 1s for the years requested.

Prepared by or under the supervision of: Melissa A. Little

Division 1-17

Request:

Regarding current approved depreciation rates.

(a) Please provide the currently approved: (1) probable retirement date; (2) survivor curve; (3) future net salvage percent; and (4) depreciation rate for each account shown on pages 76-78 (49-51 of 222) of NWA-2 Electric (2016 Electric Depreciation Study).

(b) Please provide a copy of the Commission Order that approved the depreciation rates and parameters provided in response to part (a) of this request.

(c) If possible, please provide the documents requested in part (a) electronically in Excel.

Response:

(a) Please refer to Attachment DIV 1-18 for the requested information in Excel format.

(b) The Company did not adjust depreciation rates in its last base distribution case (Docket No. 4323). The last depreciation study was approved in Docket No. 4065. Please refer to Attachment DIV 1-17-1 for Public Utilities Commission Order No. 19965A in Docket No. 4065, and Attachment DIV 1-17-2 for the previous depreciation study.

(c) Please refer to the Company's response to part (a) above.

Prepared by or under the supervision of: Ned Allis

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

PUBLIC UTILITIES COMMISSION

IN RE:

THE APPLICATION OF THE	:	
NARRAGANSETT ELECTIC COMPANY	:	**DOCKET NO. 4065**
d/b/a NATIONAL GRID FOR APPROVAL	:	
OF A CHANGE IN ELECTIC BASE	:	
DISTRIBUTION RATES	:	

DECISION AND ORDER

DATED: APRIL 29, 2010

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APPLICATION FOR APPROVAL OF	**:**	
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REPORT AND ORDER

INTRODUCTION

On June 1, 2009, the Narragansett Electric Company, d/b/a National Grid (hereinafter "NEC," "NGrid" or "the Company") filed an application to increase electric distribution rates to collect additional distribution revenues by thirty-three percent (33%) or $75.3 million. In support of its requested increase, NGrid cited the need to ramp-up capital investment to maintain and replace aging infrastructure to achieve improvement in safety, reliability and services; and increases in the cost of operating and maintaining the system as a result of inflation and rising costs of goods and services. In addition to the requested increase, the Company proposed a series of ratemaking proposals to recover costs on a collective basis that are designed to achieve a level of cost recovery and rate stability for the Company and its customers. These proposals include a recovery mechanism for the cost of employee pension and post-retirement benefits other than pensions, a recovery mechanism to support the replacement and upgrading of infrastructure through an inspection and maintenance program, a revenue decoupling mechanism which would reconcile and adjust rates in response to customer usage as a result of energy efficiency and conservation policy initiatives, a recovery mechanism to reconcile the amount of commodity-related uncollectible accounts expense and commodity associated administrative costs related to Standard Offer Service, an adjustment of base distribution rates for significant changes in delivery-related uncollectible accounts that occur because of factors beyond the Company's control, and a pilot economic development program designed to assist new and expanding businesses.

Additionally, National Grid's merger with KeySpan Corporation results in realized and projected merger savings that the Company proposes sharing with ratepayers. To reflect the customer-share of savings, the Company's filing reduces the cost of service by approximately $3.25 million annually. The impact of the proposal on a typical residential customer using 500 kWh per month would be an increase of approximately 11.2 percent or $8.95 per month. Commercial and industrial customers would experience annual bill impacts ranging from a decrease of approximately 7 percent to an increase of approximately 10 percent. The Commission may approve different rates that may be higher or lower than those proposed by the Company.

The record in this case is extensive and complex and addresses numerous contested technical and financial issues as well as broad disputes over important issues of public and ratemaking policies. In addition to receiving the voluminous written testimony and documentation filed by the Company, the Commission received voluminous and detailed pre-filed testimony and exhibits from the Division of Public Utilities and Carriers ("Division"). There were a number of intervenors, the Navy, the Rhode Island Attorney General ("RIAG"), the George Wiley Center, the Conservation Law Foundation ("CLF"), Environment Northeast ("ENE"), the Energy Council of Rhode Island (TEC-RI"), and the Energy Efficiency Resource Management Council ("EERMC") that provided additional written testimony and exhibits.

The parties and the intervenors engaged in extensive discovery propounding numerous data requests for information relating to the Company and its affiliates' management, operations and finances to which the Company responded, for the most part,[1] in a timely manner. The Commission, the Division and the intervenors also made record requests during the course of the hearing to which the Company provided detailed responses. The Division and the parties were afforded great latitude in their discovery and questioning to assure that the Commission was presented with the most comprehensive information so that a full and complete record would be available for the Commission to review prior to its decision.

The Commission conducted eleven days of evidentiary hearings on the Company's proposal in November and December, 2009. Numerous exhibits were received into evidence. The Company, the Division and the intervenors presented a total of twenty-five witnesses all of whom but two testified during the evidentiary hearing:

For the Company:

1. Thomas B. King, President of National Grid USA, provided pre-filed testimony and testified during the evidentiary hearing regarding National Grid's vision and policy objectives as they relate to the Company's rate filing.

[1] While recognizing the Company's diligence in responding to the numerous data and record requests issued in this proceeding, the Commission, on February 2, 2010 with its open meeting to decide on NGrid's request for a rate increase scheduled for February 9, 2010, had to inquire as to the status of Commission data request 3-4 issued on August 17, 2009, Commission data request 12-3 issued on December 8, 2009 and Commission data request 15-7 issued on January 12, 2010. Commission 12-3 was not provided in a clear and responsive manner until the morning of the Commission's open meeting, February 9, 2010, two months after it was issued. In fact the Chairman admonished NGrid making a point of indicating that his remarks were not a reflection on any of the attorneys involved because they were not responsible. Transcript, 2/9/10 at p. 72. While the evidentiary hearings ended on December 9, 2009, post hearing briefs were not due until January 22, 2010 and reply briefs were due until January 29, 2010. However because of the delay in providing the data response, due wholly to NGrid, which the Commission deemed necessary and accepted as part of the record, the record in this matter was not closed until February 9, 2010. In addition to the late response to certain Commission data requests, the Company did not respond to a TEC-RI data request filed on December 8, 2009 until February 4, 2010.

2. John Pettigrew, Executive Vice President and Chief Operating Officer of Electric Distribution Operations of National Grid, provided pre-filed testimony and testified during the evidentiary hearing regarding the Company's capital additions, its inspection and maintenance strategy, cost savings initiatives and facilities consolidation efforts.

3. Rudolph L. Wynter, Senior Vice President, Strategy, Marketing and Energy Efficiency of National Grid, filed pre-filed testimony and testified during the evidentiary hearing regarding the Company's uncollectible accounts expense and related proposals.

4. Susan F. Tierney, Ph.D., Managing Principal, Analysis Group, Inc., filed pre-filed testimony and testified during the evidentiary hearing regarding the Company's proposed revenue decoupling plan.

5. Timothy Stout, Vice President of Efficiency Strategy and Planning for National Grid, filed pre-filed testimony and testified during the evidentiary hearing regarding the Company's energy efficiency activities in Rhode Island.

6. Paul R. Moul, Managing Consultant, P. Moul & Associates, filed pre-filed testimony and testified during the evidentiary hearing regarding the Company's proposed return on equity and capital structure.

7. William F. Dowd, Senior Vice President of U.S. Labor Relations for National Grid, filed pre-filed testimony and testified during the evidentiary hearing regarding compensation and benefits.

8. Kimbugwe A. Kateregga, Vice President and Consultant, Foster Associates, Inc., filed pre-filed testimony presenting the Company's depreciation study and proposed depreciation rates for ratemaking purposes.

9. Robert L. O'Brien, Senior Advisor, Black & Veatch, filed pre-filed testimony and testified during the evidentiary hearing regarding the Company's proposed Revenue Requirement.

10. Howard S. Gorman, Principal, Black & Veatch, filed pre-filed testimony and testified during the evidentiary hearing regarding the Company's proposed Allocated Cost of Service, Rate Design, and related studies.

11. Alfred P. Morrissey, Lead Analyst in Electric Load Forecasting in the Energy Portfolio Management Department of National Grid, filed pre-filed testimony regarding the Company's sales forecast.

12. John E. Walter, Manager – Outdoor Lighting for National Grid, filed pre-filed testimony regarding changes to the Company's Outdoor Lighting tariff provisions.

13. Carmen Fields, Director – Community Relations/Economic Development NE for National Grid, filed pre-filed testimony and testified during the evidentiary hearing regarding the Company's proposed economic development program.

14. Julie Cannell, President, J.M. Cannell, Inc., filed pre-filed rebuttal testimony and testified during the evidentiary hearing regarding the investor perspective with respect to return on equity and access to the capital markets.

<u>For the Division:</u>

1. Bruce R. Oliver, President, Revilo Hill Associates, Inc., filed pre-filed testimony and testified during the evidentiary hearing regarding the Company's proposals for revenue decoupling, economic development, and recovery of commodity-related uncollectible accounts expense.

2. David J. Effron, a consultant specializing in utility regulation, filed pre-filed testimony and testified during the evidentiary hearing regarding the Company's revenue requirement and the distribution adjustment provision included in the Company's proposed tariffs.

3. Matthew I. Kahal, a consultant specializing economics, filed pre-filed testimony and testified during the evidentiary hearing regarding his recommendation on a fair rate of return.

4. Lee Smith, Managing Consultant and Senior Economist, LaCapra Associates, filed pre-filed testimony and testified during the evidentiary hearing regarding her review of the reasonableness and appropriateness of the allocation of costs from affiliates to the Narragansett Electric Company.

5. Dale E. Swan, Ph.D, Senior Economist and Principal, Exeter Associates, Inc., filed pre-filed testimony and testified during the evidentiary hearing regarding his evaluation of the reasonableness of the embedded, class cost-of-service study filed by Narragansett Electric Company, an appropriate allocation of the allowed jurisdictional revenue requirement among the customer classes based on costs of service and other general rate design considerations and his evaluation of the proposed rate design.

6. Bruce A. Gay, President, Monticello Consulting Group, Limited, filed pre-filed testimony and testified during the evidentiary hearing regarding his

evaluation of the Company's management and performance in the management of uncollectible accounts.

7. Richard S. Hahn, Principal Consultant, LaCapra Associates, Inc., filed pre-filed testimony and testified during the evidentiary hearing regarding the Company's proposed Inspection & Maintenance Program, the Vegetation Management Program, the Capital Plan, and the Facilities Plan.

<u>For the Intervenors:</u>

1. John Farley, Executive Director, The Energy Council of Rhode Island, filed pre-filed testimony and testified during the evidentiary hearing regarding the proposed amount of increase in revenue requirements, the appropriateness of the Cost of Service Study with respect to the current G-62 and B-62 rate classes, the reasonableness of the proposed new rate designs for G-32 and B-32, the proposed transmission rate design, the other adjustment factors, and the revenue decoupling proposal.

2. Mark Newton Lowry, Ph.D., President, PEG Research LLC, filed pre-filed testimony and testified during the evidentiary hearing on behalf of the EERMC regarding revenue decoupling.

3. Ali Al-Jabir, an energy advisor and consultant specializing in public utility regulation with Brubaker & Associates, Inc., filed pre-filed testimony and testified during the evidentiary hearing on behalf of the Navy regarding the Company's class cost of service study and proposed revenue distribution.

4. Shanna Cleveland, a staff attorney for CLF, filed pre-filed testimony and testified during the evidentiary hearing in support of the Company's decoupling proposal.

In addition to the evidentiary hearings, the Commission conducted six public comment hearings at various locations around the state. Numerous individuals provided comment during these hearings as well as at the commencement of the evidentiary hearing. Most of the comments were in opposition to the Company's request for a rate increase and expressed concern about the effect that a rate increase would have on households or businesses. Prior to the submission of post hearing briefs and in response to the Commission's investigation and the positions advanced by the Division and the intervenors, NGrid adjusted the amount of the requested revenue increase downward from $75.3 million for a total revenue increase of $62,229,000. Subsequent to the conclusion of the evidentiary hearing, the parties submitted briefs summarizing their positions and the evidence supporting those positions. The parties also submitted reply briefs commenting on the other parties' arguments. Again, and prior to the Commission's decision, NGrid revised its position to include updated estimates for Accumulated Deferred Income Tax and adjusted its claimed revenue deficiency downward to $57,766,000.

STANDARD OF REVIEW

The Rhode Island General Assembly has declared that it is the policy of the state

> to provide fair regulation of public utilities and carriers in the interest of the public, to promote availability of adequate, efficient and economical energy, communication and transportation services and water supplies to the inhabitants of the state, to provide just and reasonable rates and charges for such services and supplies, without unjust discrimination, undue preferences or advantages, or unfair or destructive competitive practices . . . . .R.I. Gen. Laws § 39-1-1; *see also* R.I. Gen. Laws § 39-2-1 (utility rates and charges must be "reasonable and just"); R.I. Gen. Laws §39-2-2 (prohibiting rate discrimination).

The Commission's review of the Company's requested rate increase or decrease must take into account this policy.

Furthermore, the legislature granted the Commission the exclusive authority to "serve as a quasi-judicial tribunal with jurisdiction, powers and duties to…hold investigations and hearings involving the rates, tariffs, tolls, and charges" of public utilities. R.I. Gen. Laws §39-1-3. The Court has continually recognized this exclusive authority, *In re Island High-Speed Ferry, LLC*, 746 A.2d 1240 (R.I. 2000); *Town of East*

Greenwich v. O'Neil, 617 A.2d 104 (R.I. 1992)(where the Court discussed the legislative intent of granting the Commission exclusive authority to regulate public utilities); *Town of New Shoreham v. Rhode Island Pub. Utils. Comm'n*, 464 A.2d 730 (R.I. 1983), and its limited authority to review Commission decisions. R.I. Gen. Laws §39-5-3; *The Energy Council of Rhode Island v. Public Utilities Commission et a.l,* 773 A.2d 853 (R.I. 2001)(where the Court reiterated that the fact-finding role in utilities cases lies solely with the Commission, and will not be disturbed as long as the Commission's decision is fairly and substantially supported by legal evidence that is specific enough for the Court to ascertain whether the factual findings upon which the Commission's decision is premised afford a reasonable basis for the result reached *(citations omitted)*).

Pursuant to R.I. Gen. Laws §39-3-12, NGrid alone, and not the Division, bears the burden of proving that its requested rate increase is necessary in order to obtain just and reasonable compensation for the services it renders. R.I. Gen. Laws §39-3-12; *Michaelson v. New England Telephone and Telegraph Company*, 121 R.I. 722, 404 A.2d 799 (1979). The Commission is not bound by a specific formula in determining what is just and reasonable but has discretion to select a measurement approach that is supported by the record. *Providence Gas Co. v. Burman*, 119 R.I. 78, 376 A.2d 687 (1977). The Commission is not bound to use a particular method used in a previous case, *Michaelson v. New England Tel. & Tel.*, 404 A.2d 799 (R.I. 1979); nor is it bound to accept the entire testimony of an expert. *See Valley Gas Co. v. Burke*, 446 A.2d 1024 (R.I. 1982) *citing Rhode Island Consumers' Council v. Smith*, 111 R.I. 271, 302 A.2d 757 (1973).

NATIONAL GRID'S FILING

As set forth above, NGrid filed its original application on June 1, 2009.[2] With its application and in support thereof, it filed pre-filed testimony of thirteen witnesses[3] listed above. Each of their testimonies and rebuttal testimonies will be summarized.

A. Thomas B. King
President, National Grid USA

The purpose of Mr. King's testimony was to provide an overall review of the Company's vision. He noted that NGrid was seeking to recover a revenue deficiency of $75.3 million based on a rate base of approximately $624 million. This results in an 11.2% increase in the total monthly bill of a 500 kWh residential customer receiving standard offer service. Mr. King described NGrid as being the foremost international electricity and gas company, delivering unparalleled efficiency, reliability and safety, vital to the well being of its customers and communities and being committed as an innovative leader in energy management and guardian of the global environment for future generations.

Mr. King claimed NGrid as transforming Electricity Distribution Operations to meet changing demands of customers by reducing costs through efficiency and effectiveness and addressing all aspects of operations. He pointed out that NGrid makes decisions with climate change issues and carbon reduction goals at the forefront and noted that the Company has award winning energy efficiency programs that through 2008

[2] The June 1, 2009 date is significant, because it represents the day six months prior to the expiration of the rate freeze established in Docket No. 3617. At the time of the filing, R.I. Gen. Laws §36-3-11 allowed the Commission to suspend the taking effect of any change for a period of up to six months in order to conduct a thorough investigation.
[3] Julie Cannell filed rebuttal testimony only.

produced cumulative annual savings of 7 million megawatt-hours in RI. He asserted that state and federal energy policies are consistent with NGrid's vision.

Mr. King noted that the Company shares the same goals as the Commission, the Division and the other stakeholders in:

1. providing safe, reliable and efficient energy delivery to its customers in its service area;
2. fulfilling the broad objectives of the Comprehensive Energy Conservation, Efficiency, and Affordability Act of 2006 and federal energy policy; and
3. addressing the specific issues of particular customers.

Mr. King testified the merger plan of NEC with Blackstone Valley Electric Company ("BVEC") and Newport Electric Corporation ("Newport") in 2000 reduced distribution rates by $2.7 million and froze rates and then again in 2004 rates were reduced by an additional $10.2 million and frozen again through 2009. According to Mr. King, the Company now needs to reset rates to enable it to meet its basic service obligations and to provide safe and reliable energy services. Mr. King noted that in order to continue moving forward, NGrid needs cost recovery of on-going operating costs, timely recovery of capital investments and a rate of return that encourages an incentive to invest aggressively in Rhode Island. He indicated that in order to sufficiently recover on-going operating costs, a reconciling mechanism to account for inflation and mitigation of load growth revenues was necessary.

Mr. King also provided testimony regarding how the uncollectible accounts expense has grown significantly. He noted that this was due in part to increasing costs in commodity services that were not anticipated at the time of restructuring and are beyond control of NGrid and its customers. To address this issue, Mr. King indicated that NGrid desires a full reconciliation of costs for commodity service and the ability to adjust the distribution portion of uncollectibles if it is shown that there was a substantial increase in these costs that was beyond the control of the Company. Mr. King also discussed the proposed mechanism to reconcile pension and other post employment benefits ("OPEB") expense indicating its necessity because these costs are volatile and beyond Company control.

Mr. King also discussed the Company's revenue decoupling proposal stressing its necessity to balance the ramp up of energy efficiency with the duty to shareholders to assure adequate recovery of sufficient revenue to cover costs. He noted that the decoupling proposal will allow NGrid to aggressively promote and implement all cost-effective energy efficiency and other demand resources. Finally, Mr. King indicated that the proposed return on equity of 11.6% will allow NGrid to attract and maintain investors and debt to fund its needs.

B. John Pettigrew
Executive Vice President and Chief Operating Officer
Electric Distribution Operations of National Grid

Mr. Pettigrew's testimony described the electric distribution operations and discussed the proposals related to those operations. He filed both pre-filed and rebuttal testimony. Mr. Pettigrew noted that the electric distribution operations include managing assets and construction, operation and maintenance of the infrastructure. He described the service territory as consisting of 1,070 square miles in thirty-eight of Rhode Island's cities and towns. Mr. Pettigrew indicated that NGrid was proposing a substantial ramp-up of system maintenance and capital investment to maintain and improve the system. His direct testimony detailed how NGrid met its reliability performance target metrics in

2008 for both the System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Duration Index ("SAIDI").

Mr. Pettigrew identified NGrid's vision for establishing an Annual Work Plan that consists of a proactive inspection and replacement-oriented approach. Mr. Pettigrew described the approach as being proactive with capital investment being driven by inspection data, field conditions and systematic repair and replacement schedules rather than performance failures. He noted that this new Inspection and Maintenance ("I&M") strategy will include a five-year inspection cycle that will complete twenty percent (20%) of inspections each year.

Mr. Pettigrew identified four general categories of work activities: system capacity and performance, asset condition, statutory or regulatory requirements and damage/failure projects. He noted that costs will be incurred with implementation of the I&M strategy resulting from an increase in Operation and Maintenance ("O&M") expense since additional staffing will be required, an increase in capital costs because of necessary repairs and an increase in incremental O&M expense for minor work that is not capital. Mr. Pettigrew described the cost of the O&M related to I&M program in 2010 to be $4.7 million, an increase of $2.6 million over the test year. The Company also expects to increase its capital investment from approximately $8.2 million to $11 million for repair projects. Mr. Pettigrew stated that capital expenditures from the I&M strategy would be recovered through the revenue decoupling mechanism. Mr. Pettigrew also noted an increase in $2 million over the test year for the vegetation management strategy which will be a circuit based approach as opposed to the current community specific approach to pruning, shorter cycle lengths for greater pruning activities and additional clearing between conductors and trees or tree limbs.

Mr. Pettigrew noted that the strategies proposed by NGrid will result in a capital investment plan of $59.9 million in 2009 and $75.9 million in 2010. He described the capital recovery mechanism proposed by the Company which would allow for real-time recovery of the revenue requirement associated with post rate-year capital investments. He pointed out that this is necessary for NGrid to maintain financial health, complete projects necessary to maintain and improve the system, attract capital at a reasonable cost, and provide a fair return.

Mr. Pettigrew also provided testimony regarding the property consolidation strategy developed following the merger with KeySpan. He noted that the consolidation strategy to close and consolidate facilities will yield economic and non-economic benefits of approximately $10 million through 2018 and $29 million through 2028. Mr. Pettigrew described the three types of facilities that serve customers: operations centers, special purpose facilities and main office facilities. He pointed out that there are twelve operations centers in Rhode Island. He also noted that as of April 2010, there will be one special purpose facility (down from four) in Northborough, MA the purpose of which will house the control and dispatch center for electric and gas distribution and electric transmission. He indicated that the Reservoir Woods facility in Waltham, MA was chosen to house the main office facilities because it allowed for consolidation into one building, unlike other alternatives that required significant renovations to existing buildings. Mr. Pettigrew identified the Rhode Island's allocated share of the

Northborough and Reservoir Woods facilities for calendar year 2010 to be $257,940 and $323,494 respectively.

C. Rudolph Wynter
Senior Vice President, Strategy, Marketing and
Energy Efficiency of National Grid

Mr. Wynter's testimony described NGrid's management of its uncollectible accounts as well as its proposal for recovery of delivery and commodity-related uncollectible expense. He noted that the increase in uncollectibles is because of the increase in commodity price and economic factors that include weather, the level of governmental assistance and other energy costs. Mr. Wynter detailed the increase in write-offs over the past five years. He identified decisions made in relation to billing and collection and the timing and term of the moratorium as counteracting NGrid's efforts to collect revenue and mitigate write-offs. Mr. Wynter described some of the strategies for minimizing uncollectibles such as outbound calls, field visits and service termination for non-payment. He detailed the behavioral scoring model employed by NGrid to determine what strategy to use noting that the Company uses an approach that is flexible to address customer specific circumstances.

Mr. Wynter described the Company's three proposals for uncollectible recovery. The first proposal would allow for commodity-related uncollectible expense to be recovered through Standard Offer Service rates on a fully reconciling basis and would equal the actual net write-offs experienced in each year. He described this proposal as necessary because NGrid has no control over prevailing conditions or prices in commodity markets. Unbundling of electric rates by properly allocating costs to distribution and commodity services will promote retail electric competition, and full reconciling will ensure customers do not pay more than the actual uncollectible expense, which is consistent with the Commission's decision's in Docket Nos. 3401 and 3943 where the Commission recognized the appropriateness of recovering commodity related bad debt costs through the commodity charge. The reconciling mechanism would be applied if the Company's actual expense exceeds the amount allowed for in base rates, which would be calculated based on a two-year average of actual write-off experience, if greater than $500,000 and contingent on the Company demonstrating that it had made 510,000 outbound calls and 41,000 field visits and further, that the increase is due to factors beyond the Company's control. Mr. Wynter noted that without a reconciling mechanism, NGrid would need to file more frequent rate cases which will have a detrimental effect on investor perception of the Company's risk profile.

The second proposal would allow for the creation of two customer advocate positions to deal directly with Rhode Island electric customers by assisting those eligible customers in identifying and enrolling them in programs that are available to them. The rate year cost of these positions would be $190,943. Finally, Mr. Wynter provided testimony to support increasing the revenue requirement by $376,255 from the test year to reflect implementation of a mitigation plan for incremental costs associated with substantially increasing the level of outbound calls as well as the increased level of inbound calls that will result from a higher level of collections activity.

D. Susan F. Tierney, Ph.D
Managing Principal, Analysis Group, Inc.

Dr. Tierney provided extensive testimony in support of NGrid's proposal for revenue decoupling. She defined revenue decoupling as a ratemaking feature designed to break the link between the revenues a utility receives and the level of sales it experiences.

She noted that it eliminates the incentive a utility has to expand its sales. Dr. Tierney pointed out that the Revenue Decoupling Ratemaking Plan ("RDR Plan") is shaped with traditional ratemaking practices and changed circumstances to ensure that rates reflect the cost of service, that the Company will be able to fund reliability improvements and investments while operating its system safely and reliably and that the Company's financial interests are better aligned with customer's interests and state policy directives by encouraging customers to better manage and/or reduce energy usage and effectively manage energy bills.

Dr. Tierney identified the Company's RDR Plan as including two elements: base rates as set by the Commission in a rate case and a RDR Plan Adjustment Factor that will modify rates annually. She described the RDR Plan as including a revenue decoupling mechanism, an inflation adjustment, a component to provide revenues related to cumulative net capital spending above amounts supported in base rates and a component to provide revenues for the effects of increased capital spending levels in the current year based on actual recent levels of capital additions made by the Company.

Dr. Tierney described the various policies that support revenue decoupling. She noted that federal policy goals include the desire to promote the procurement of least cost retail energy supply and the need to increase or maintain the reliability of retail energy supply and to address environmental impacts associated with energy production and use. She also noted that Rhode Island state policy encourages decoupling specifically in the Comprehensive Energy Conservation, Efficiency and Affordability Act of 2006 which requires least-cost procurement as a key element of the state's energy plan. Finally Dr.

Tierney pointed out that the American Recovery and Reinvestment Act ("ARRA") will provide for at least $58 million to Rhode Island for energy efforts.

Dr. Tierney also identified the two barriers that inhibit the realization of cost-effective energy efficiency: those that prevent customers from undertaking all cost-effective opportunities for energy efficiency like market barriers, customer barriers, investments with long payback periods, behavioral biases, challenges in gaining access to financing, etc. and factors that create disincentives resulting in utilities pursuing cost-effective energy efficiency less aggressively than the economics of the programs would warrant. Dr. Tierney noted that decoupling eliminates the tension between the utility's reliance on the volume of sales for its revenue requirement and the implementation of energy efficiency programs that should result in reduced sales. She distinguished between the elimination of the disincentives and the need for the continuation of positive incentives. She justified the need for continued positive incentives by noting that utilities will be more likely to devote substantial attention and resources to energy efficiency programs if they are allowed to earn a financial return on those activities.

In further support of her arguments for the Company's decoupling proposal, Dr. Tierney stressed that decoupling will lead to lower electric bills for customers that participate in energy efficiency programs. She indicated that currently twelve electric utilities in seven states rely on mechanisms that incorporate revenue decoupling and she believes that more states will adopt revenue decoupling. Dr. Tierney also noted that decoupling will stabilize customers' bills and the utility's revenues. She pointed out that revenue stability is perceived by financial markets as beneficial to a utility's financial strength. Dr. Tierney cautioned that even with revenue decoupling, a utility must still manage costs and that Commission oversight of the utility can still occur through annual filings.

Dr. Tierney described the proposed RDR Plan in great detail. She noted that the plan consists of two components: a look back component and a look ahead component. The look back step ensures recovery of NGrid's Annual Target Revenue ("ATR") and is built on a class specific revenue requirement resulting from the rate case. The ATR includes an adjustment to reflect net distribution capital expenditures ("CapEx") and an adjustment for the incremental effects of a net inflation adjustment. The Company is not proposing an adjustment to the ATR to account for changes in the number of customers served. Dr. Tierney noted that the annual reconciliation will reconcile the actual distribution revenue billed and the actual ATR for the prior year. In subsequent years, the reconciliation filing will include adjustments for net CapEx and net inflation and will have to be reviewed and approved by the Commission. Dr. Tierney described NGrid's ATR component for recovery of net CapEx as designed to provide support for incremental additions to distribution investment above and beyond that which can be supported by the depreciation expense embedded in the Company's base rate revenue requirement. She noted that this needs to be adjusted because decoupling removes revenues from increasing sales that have previously been used to fund capital investments between rate cases.

Dr. Tierney identified the ATR as including a revenue requirement to support the Company's cumulative net CapEx which will include the Commission approved distribution-related capital expenditures net of the level of the annual depreciation expense allowance embedded in base rates and the sum of the net CapEx approved as a part of the prior years' RDR Plan reconciliations. Dr. Tierney noted that if the net CapEx in a subsequent year is less than the depreciation expense in base rates then that year's net CapEx would be negative. She pointed out that all capital expenditures made for distribution system investments would be eligible to be included in the determination of the net CapEx adjustment.

Dr. Tierney described the other adjustment to the look back portion of the RDR Plan, the net inflation adjustment which she stated would be calculated by multiplying operating expenses by the net inflation factor. She noted that the net inflation factor reflects a measure of economy-wide inflation for the time period in question net of a fixed adjustment for industry productivity. Based on her assessment of recent estimates of utility productivity, she proposed a 0.5% productivity offset which she described as a conservative estimate.

The look ahead step is the revenue adjustment mechanism to the RDR Plan. Dr. Tierney noted that this step generates revenues to address the impact of inflationary pressures and increasing capital requirements, will begin on January 1, 2011 and will make two net CapEx adjustments: (1) the cumulative net CapEx adjustment already approved by the Commission in the instant and prior reconciliation proceedings based on the revenue requirement for net CapEx included in the prior year's ATR; and (2) the current year net CapEx adjustment which will account for the incremental effect of the net CapEx anticipated in the coming year and will be based on 75% of the average level of actual annual net CapEx for the prior two years, and if that amount exceeds the allowance for depreciation expense it will be included in the RDR Plan adjustment for the current year. Dr. Tierney indicated that the Company's proposal includes the requirement of notification to the Commission by August 31 of each year if the difference between the year-to-date actual revenue and the year-to-date ATR is ten percent above or below the actual ATR and the Company does not anticipate this discrepancy falling below the ten percent threshold in the coming months.

E. Timothy Stout
Vice President of Efficiency Strategy and Planning
for National Grid

Mr. Stout provided testimony to discuss NGrid's Energy Efficiency ("EE") programs and future goals for expanding them. He identified the current programs that are offered for electric and gas customers. Mr. Stout noted that current incentives will not be sufficient to address the impact on distribution revenue that would result from expanding Company's EE programs. He pointed out that over next three years, the Company will be implementing a dramatic expansion of current EE programs and pointed out that these programs will create over $280 million of net lifetime benefits for Rhode Island consumers. He noted that the 2009 budget for EE programs will total $32.4 million ($7.2 million for residential, $2.6 million for residential low income and $20.8 million for C&I customers) and provided a description of DSM programs available for consumers in Rhode Island.

Mr. Stout indicated that when the Company proposed the increase in EE in its three-year plan, it did so anticipating the approval of revenue decoupling. He indicated that in order to achieve the $280 million in net benefits, NGrid projects $102 million in efficiency program implementation and evaluation spending over the three year period. He stated that the short term effect of an increase in EE on consumption is that an individual participating customer's electric use may decrease. However, in the long term, the deeper penetration of EE through the EE programs may lead to the presence of more EE technologies in the market.

F. Paul R. Moul
Managing Consultant, P. Moul & Associates

Mr. Moul provided testimony about the Company's proposed capital structure and return on equity. He noted that the proposed capital structure assumes completion of a financing application with the Division,[4] which would reduce Narragansett Electric's capital structure from 77.99% common equity to approximately 50% common equity by issuing $512 million in long term debt. The new long-term debt will repay short term debt and $356 million will be used to pay dividends. Mr. Moul noted that the Company wants to free up short-term debt so that it can temporarily fund new construction work in progress until such time as the projects are placed in service and permanently financed. Mr. Moul pointed out that on average in 2008, capital structures of electric utilities included 48% equity and he stated that this ratio was expected to increase to 50%. Mr. Moul identified the proposed capital structure to be 50.05% common equity, 44.78% long-term debt, 4.98% short-term debt and 0.19% preferred stock. He noted that NEC's preferred stock had an annual dividend rate of 4.5%. He pointed out that the Company proposes to use the actual cost of debt per the debt issuance approved by the Division and estimated the cost of long-term debt to be 6.70% inclusive of issuance costs. He identified the short-term debt rate to be 2.50%. Mr. Moul concluded that the Company should be afforded an opportunity to earn an 8.98% rate of return which reflects a cost of equity of 11.60%.

[4] In Docket No. D-09-49, NGrid filed an application with the Division on June 18, 2009, subsequent to NGrid's filing of Mr. Moul's direct testimony. This matter was resolved by Settlement Agreement submitted on November 18, 2009 and approved by the Division effective December 9, 2009.

Mr. Moul noted that the rate of return allowance must: (1) provide the Company with an opportunity to cover its interest and dividend payments; (2) provide a reasonable level of earnings retention; (3) produce an adequate level of internally generated funds to meet capital requirements; (4) be adequate to attract capital; (5) be commensurate with the risk to which the Company's capital is exposed; and (6) support reasonable credit quality. He recommended that the Commission consider current investor sentiment when determining cost of equity, like the financial climate and all of the events occurring in the financial markets that have made investors more risk-adverse. He pointed out that the DCF model alone does not capture volatility risk so it was advantageous to use more than one method to determine the cost of equity. He stated that NGrid needs to earn a fair rate of return to maintain a financial profile that will provide the Company with the ability to raise capital under all market conditions and satisfy investor requirements.

Mr. Moul explained in great detail how he concluded that an 11.60% cost of equity was appropriate. He described the proxy group he used which he called the RDM Electric Group that consisted of seven electric or combination electric and gas utility companies. The companies in the proxy group were all included in the Value Line Investment Survey, currently paid a dividend on their common stock, were not presently the target of an announced acquisition or merger, had at least 60% of their assets devoted to regulated utility operations, currently have a revenue decoupling mechanism in place and have a credit quality rating of Baa2/BBB or higher. Mr. Moul's analysis considered four measures of the cost of equity: Discounted Cash Flow ("DCF"), Risk Premium ("RP"), Capital Asset Pricing ("CAPM") and Comparable Earnings ("CE"). He took the average cost of equity for all of the proxy companies using each specific method and then averaged the DCF, RP and CAPM results to conclude that 11.60% was an appropriate cost of equity.

Mr. Moul explained how risk is assessed and noted that while the RDM will mitigate some risks, it will not fully eliminate the lag in revenue recovery associated with new capital investment and new technologies that the Company actively supports. He identified some other categories of relative risk. These categories include size, market ratios, common equity ratio, return on book equity, operating ratios, coverage, quality of earnings, internally generated funds and betas. Mr. Moul noted that after the capitalization restructuring that will be proposed to and must be approved by the Division, the Company's financial risk will be aligned with his proxy group.

Mr. Moul defined the DCF method as an expectation model that seeks to explain the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. He noted that the DCF return on common stocks consists of a current cash dividend yield and future price appreciation of the investment. He stated that the average dividend yield for twelve months for his proxy group was 4.38% but increased to 4.86% and 5.15% for the most recent six and three month periods. He used the 4.86% and adjusted this for a dividend yield of 5.02%. In the growth rate analysis, he considered growth in the financial variables, i.e., earning per share, dividends per share, book value per share and cash flow per share for his proxy group and concluded that an investor-expected growth rate of 6% is within the array of growth rates shown by the analysts' forecasts or earnings growth. He also added a leverage adjustment of 0.15%. His DCF analysis yielded a cost of equity of 11.17%.

Mr. Moul defined the RP method as determining the cost of common equity capital by corporate bond yields plus a premium to account for the fact that common equity is exposed to greater investment risk than debt capital. He noted that a 6.50% yield represents a reasonable estimate of the prospective yield on long-term A- rated utility bonds. For the twelve months ending March 2009, Mr. Moul stated that the average monthly yield on Moody's A- rated index of public utility bonds was 6.58%. He analyzed four time periods of risk premiums and chose the two shortest because they were neither the highest nor the lowest risk premium and averaged them to come up with what he described as a reasonable risk premium of 6.23% for Standards and Poor's ("S&P") public utilities in this case. He recognized the difference between the S&P utilities and his proxy group and considered the differences in the fundamentals of the two groups to come up with a 5.50% common equity risk premium in this case which is 88% of the S&P group and reflective of his proxy group as compared to the S&P group. Thus, the cost of common equity being the sum of the prospective yield of 6.50% and the equity risk premium of 5.50% equals 12%.

Mr. Moul defined the CAPM as using the yield on a risk-free interest bearing obligation plus a rate of return premium that is proportional to the systematic risk of an investment. He noted that it consists of three components: a risk-free rate of return, the beta measure of systematic risk and the market risk premium derived from the total return on the market of equities reduced by the risk-free rate of return. He concluded that for his proxy group the cost of equity using the CAPM was 11.80%. Lastly Mr. Moul considered the CE and looked at other companies whose prices are not subject to cost-based ceilings. The average of the rate of return on common equity for his proxy group using the CE approach was 14.9%. In order to reach his conclusion that 11.60% was an appropriate cost of equity, Mr. Moul used the average of his calculations of the DCF, CAPM and RP methods.

G. William F. Dowd
Senior Vice President of U.S. Labor Relations
for National Grid

The purpose of Mr. Dowd's testimony was to support the revenue requirement as it relates to employee compensation. He explained NGrid's compensation policy, called the Total Rewards Program, which is an overall package of wages and benefits that is market competitive, offers flexibility and choice and supports a high performance culture by directly linking performance to rewards. He noted that NGrid monitors the marketplace to ensure that the cost of benefit programs is cost-effective and sufficient to attract qualified, highly skilled employees. He explained that NGrid commissioned a market analysis of wages and benefits after the KeySpan merger that indicated that offering less costly benefit plans coupled with greater level of variable pay would be in line with what other employees are offering in the marketplace.

Mr. Dowd indicated that NGrid has made changes to medical, dental and life insurance programs to reduce costs. Specifically, NGrid increased co-pays for office visits and prescription drugs and implemented a deductible/co-insurance arrangement for in-patient hospital care, replaced a prescription drug program with CVS Caremark, increased co-shares for dental from 20% to 35% and for major restorative from 50% to 60%, eliminated adult orthodontia and reduced life insurance overage from two times annual pay to one times annual pay.

Mr. Dowd described the compensation program as consisting of base pay and variable (incentive) pay. He noted that 100% of companies surveyed that were the size of NGrid had variable pay plans and over 90% of employees participated. He noted that the variable pay plan is aligned with financial performance, the health of the Company and the achievement of established performance standards that directly benefit customers. He indicated that NGrid's compensation plan is designed to encourage good performance with 40% to 50% of incentive pay being linked to individual objectives that are tied to service quality measures such as safety, reliability and customer satisfaction.

Mr. Dowd testified that for non-union employees, base pay wages go into effect July 1 of each year. He noted that NGrid seeks to set pay at approximately the median level for comparable companies in the Northeast. He explained that variable pay is determined following the close of each fiscal year, and both variable and merit based pay are linked to performance results through appraisal and measurement processes. Mr. Dowd described the $22,657,396 operating expense for non-union payroll as $17,200,340 being allocated from NGSC and $855,032 being allocated from KeySpan. He identified this $960,779 increase over test year expense as reflecting an overall 1.5% wage increase for July 1, 2009 through June 30, 2010 and a 3% increase beginning July 1, 2010 through December 31, 2010 and as being consistent with historic levels. He noted the $23,714,167 operating expense for union payroll as $4,274,121 being allocated from NGSC and $38,901 being allocated from KeySpan. He pointed out that wage increases ranging from 2.5% to 3.5% are through June 30, 2010 and were previously negotiated with the different unions.

Mr. Dowd described NGrid's benefits programs to include medical coverage, dental coverage, life insurance coverage, and long-term disability coverage, paid vacations and holidays, a defined benefit pension plan, a defined contribution or 401(k) plan and post retirement benefits. He noted that the Company is self insured and also provides health and wellness programs and a disability benefit program. He indicated that NGrid projects an 8% increase in costs associated with medical benefits and a 3% increase in costs associated with dental benefits.

For all non-union new hires after July 15, 2002, Mr. Dowd stated that NGrid implemented a common cash balance pension plan which is less costly than the prior final average pay type plan. He noted that NGrid now requires employees to pay for pre-age 65 post retirement medical insurance at the same rates as active employees for non-union and that the reimbursement of Medicare Part B premium has been eliminated and that there has been a reduction in life insurance at retirement.

<u>H. Kimbugwe A. Kateregga, Ph.D</u>
<u>Vice President and Consultant, Foster Associates, Inc.</u>

Dr. Kateregga's testimony described the 2009 depreciation rate study. He indicated that depreciation studies are necessary because of the need to periodically assess the reasonableness of the parameters and accrual rates used to determine vintage service life and to allow for proper ratemaking to achieve timely capital recovery. He explained the steps to conducting a depreciation study as collecting plant accounting data to conduct a statistical analysis of past retirement experience, estimating service life statistics from an analysis of past retirement experience or a life analysis, projecting a life curve by blending past retirement experience with an expectation about future retirements to obtain a projection life curve or life estimation, estimating net salvage applicable to future retirements and analyzing the adequacy of recorded depreciation reserve.

He noted that the parameters estimated from service life and net salvage studies are integrated into the formulation of an accrual rate based upon a selected depreciation system. He identified three elements of a depreciation system: (1) methods (retirement, compound-interest, sinking-fund, straight-line, declining balance, sum-of-years'-digits, expensing, unit-of-production, net revenue); (2) procedures (total company, broad group, vintage group, equal-life group, unit summation, item; and (3) techniques (whole-life, remaining-life, probable-life). He indicated that Foster Associates conducted statistical life studies for plant and equipment and net salvage analysis for plant and equipment. After an analysis of the recorded reserve, Dr. Kateregga found a difference of approximately $23.5 million to be amortized over the composite weighted-average remaining life of each rate category using the remaining life depreciation rates proposed by the study. He found that rebalancing of depreciation reserves is appropriate to offset imbalances attributable to passage of time and parameter adjustments. He indicated that the current depreciation system is composed of straight-line method, vintage group procedure, and remaining-life technique and did not recommend that this change. He recommended a composite rate of 3.20%. This is a reduction of 0.14% and will result in a reduction in this expense of $1,974,298.

<u>I. Robert L. O'Brien</u>
<u>Senior Advisor, Black & Veatch</u>

Mr. O'Brien provided testimony that he based the revenue requirement on the test-year ending December 31, 2008. Mr. O'Brien noted that the total revenue increase of $75,285,321 is a combination of an increase to base distribution rates of $65,533,534 and uncollectible amounts related to SOS commodity related revenue of $9,751,787. He pointed out that this level of revenue will allow NGrid to earn an 8.98% rate of return on a rate base of $623,948,473. He identified a total revenue requirement of $288,775,921 which does not include the commodity related reconciliation mechanism of $9,751,787 and is the sum of the cost of service of $232,745,348 and net income of $56,030,573 (8.98% of rate base of $623,948,473).

Mr. O'Brien made a number of adjustments to operating revenue including removing SOS, transmission O&M, energy efficiency activities, CTA merger synergies, net impact of the November 2007 storm, and the gross receipt tax. He increased regulatory expense, reduced uncollectible expense, classified charitable donations as an operating expense, included a SOS Cost Adjustment mechanism for commodity write-offs and adjusted investment tax credit for the Integrated Facilities Agreement ("IFA") portion of the expense. Mr. O'Brien also made a number of adjustments to operating expenses totaling $18,470,006. He adjusted salaries and wages by $3,092,128 to account for union and non-union wage increases through the end of the rate year. He adjusted medical and dental expense by $713,244 to reflect increases in medical and dental expense through the end of the rate year and adjusted group insurance expense by $48,661.

Mr. O'Brien made an adjustment of $4,470,254 to reflect increased pension expense through the end of the test year and an adjustment of $1,070,902 to reflect increased OPEB expense. He adjusted the Thrift Plan – Company Match by $144,870, Information Services Leasing Expense adjustment by $412,103 and Facilities Capital Improvement Rent Expense by $544,455. Mr. O'Brien made adjustments to Union

Labor Staffing of $1,432,583 to account for new union labor through the end of the rate year and made an adjustment for the $190,943 cost of adding two (2) new Customer Advocate positions. He amortized $1.73 million of rate case expense over a two year period. He made an inflation adjustment of $493,198, an adjustment for seasonal employees and added $376,255 for the uncollectibles mitigation expense described by Mr. Wynter. He included $1 million for the economic development program explained by Ms. Fields and approximately $2 million for the vegetation management ramp up and approximately $2.1 million for the inspection and maintenance program both testified to by Mr. Pettigrew.

Mr. O'Brien made adjustments for uncollectible expenses and added approximately $3.1 million for the environmental response fund. He included the annual storm contingency fund contribution of approximately $1 million. Mr. O'Brien noted that the net merger synergies from NGrid's acquisition of KeySpan are projected to be annual steady state of $6.5 million, after accounting for costs-to achieve or $2.1 million per year for a 10 year amortization period of which the Company's share is $3.25 million. Mr. O'Brien indicated that NGrid requires the Commission to approve the creation of a regulatory asset under FAS 71 for deferral and amortization of Costs to Achieve ("CTA") which is consistent with the Commission's decision in Docket No. 3943. Mr. O'Brien made adjustments for municipal taxes, payroll taxes and depreciation.

Mr. O'Brien calculated rate base using the five quarter average for the rate year plant in service of $1,232,746,925, which he then reduced by a five quarter average of $516,525,305 in accumulated depreciation. He used a net revenue lag of 1.39% for cash working capital for the rate year of $17,789,123. Mr. O'Brien also described the reconciliation adjustment mechanisms proposed by the Company. The Company proposed adjustment mechanisms for its Pension and OPEB, Inspection and Maintenance Expense, Standard Offer Service Cost and Revenue Decoupling.

J. Howard S. Gorman
Principal, Black & Veatch

Mr. Gorman provided testimony regarding the Company's proposed Allocated Cost of Service, Rate Design, and related studies. He indicated that the Company performed an Allocated Class Cost of Service Study ("ACOSS") to assign each element of the revenue requirement to the respective customer classes in order to determine the costs of providing service to each rate class. Mr. Gorman described in detail the three step process used to analyze the revenue requirement: functionalization, classification and class allocation. He identified the functions as sub-transmission, primary distribution, secondary distribution and billing and identified the classifications as demand or customer.

Mr. Gorman noted two guiding principles in the revenue allocation process: reflecting the results of the ACOSS as closely as possible and mitigating extreme rate impacts on rate classes and on individual customer subgroups. He described the Company's proposal to eliminate the rate classes 3,000 kW Demand Rate G-62 and 3,000 kW Demand Rate B-62 and transfer the existing customers to Rates G-32 and B-32. For rate design, the Company combined 200 kW Demand Back-up Rate B-32, 200 kW Demand Rate G-32, 3,000 kW Demand Back-up Rate B-62 and 3,000 kW Demand Rate G-62. He noted that NGrid proposed maintaining the Back-up Service Rate B-32; however, if the Commission approved the revenue decoupling proposal, the Company would be willing to terminate Rate B-32 effective with the implementation of the RDM and would transfer all back-up service customers to Rate G-32, under which customers are charged only for actual use of the distribution system at their peak hours.

Regarding rate design, Mr. Gorman described the Company's proposal to change the energy based charges for Rate A-60 low income customers to make it the same as the A-16 residential rate. He also explained the Company's proposal to increase the monthly customer charge for the A-16, C-06, G-02 and C&I Large Demand rate classes. He described NGrid's proposal to change the transmission rate design so that transmission costs are based on each rate classes' contribution to the Company's monthly peak. He noted that if the Company's proposed rate increase is approved, it would cause a 500 kWh per month residential customer's bill to increase by $8.95 or 11.2% from $79.71 to $88.66.

K. Alfred P. Morrissey
Lead Analyst in Electric Load Forecasting in the
Energy Portfolio Management of National Grid

Mr. Morrissey provided testimony regarding the Company's sales forecast. He described how he developed the gigawatthour sales forecast in two steps: econometric forecast of gWh sales based on economic conditions, weather, electricity price and days billed and energy efficiency savings based on the DSM program, their life cycle and initiatives NGrid has committed to for 2009 and 2010. He noted that the differences in the level of DSM savings between the test year and the rate year were used to adjust econometric forecast in 2010 lowering gWh sales by 0.4% Mr. Morrissey indicated that the forecast shows a 1.6% drop in gWh sales in 2009 because of the recession and a 1.1% increase in 2010 as the economy recovers. He pointed out that since 2005, gWh sales have declined at an average rate of 1.1% per year. He stated that a number of things have contributed to the 2010 sales forecast including commercial employment, real personal income, gross domestic product and the minimal growth in population.

Mr. Morrissey explained how he determined the monthly peak demand forecast and noted that the average monthly peaks are forecast to be 1.4% lower in 2010 than in 2008. He indicated that DSM savings on the summer peak amount to 7.6% of the actual 2008 summer peak and that these savings are expected to grow by 5.8 MW between the 2008 test year and the 2010 rate year reaching 9% of the summer peak load. He pointed out that this has the effect of lowering the model-produced 2010 peak forecast by approximately 0.4%. He also noted that DSM savings on the winter peak demand, which equaled 10.3% of the actual 2008 winter peak, are expected to fall by 22.5 MW between the 2008 test year and the 2010 rate year which has the effect of raising the 2010 peak forecast by approximately 1.7%. He identified the overall adjustment to the model-produced average monthly peak forecast for 2010 was an upward adjustment equal to 15.4 MW or 1.1%.

L. John E. Walter
Manager, Outdoor Lighting for National Grid

Mr. Walter provided testimony regarding the changes to NGrid's Outdoor Lighting tariff provisions. He identified the two tariffs for street and area lighting as the S-10 Rate which is limited service-private lighting for residential, commercial and industrial customers and the S-14 Rate which is general street and area lighting for municipal customers. Mr. Walter discussed a number of housekeeping changes, updated rates and charges to reflect the Company's allocation of its COS and described the creation of a separate Decorative Street and Area Lighting option which would allow for the Company to provide a selection of ornamental or historic style post top luminaries and anchor based standards. He also discussed the Company's proposal to offer luminaire facility rates for two wattages of metal halide floodlight luminaires for which there are currently a limited quantity of facilities in service for customers of the former Eastern Utility Associates ("EUA").

Lastly, Mr. Walter provided testimony about the adoption of a temporary turn-off rate provision for S-14 which would provide that the customer would continue to pay their balance due between one and three years. Lastly, Mr. Walter discussed the application of a "Lighting Service Charge" which would be assessed to customers for Company responses to service requests which do not involve lighting facilities owned by the Company. This would apply to street lighting customers except if the failure was directly related to Company owned facilities and the malfunction was caused by a third party attachment and there is an agreement between the customer and third party, and NGrid will hold the third party responsible.

<u>M. Carmen Fields</u>
<u>Director, Community Relations/Economic</u>
<u>Development NE for National Grid</u>

Ms. Fields provided testimony regarding NGrid's proposed Economic Development Program. She noted that the cost of the program was $1 million per year. She described the program as dedicated to new economic development pilot initiatives noting that New York currently has economic development programs. She explained that the program has three parts. The first part is a targeted infrastructure improvement program that will address the development of key industrial sites and buildings where the existing energy delivery infrastructure is a barrier to economic growth. The second part is an urban revitalization program that will focus on the redevelopment of vacant buildings in urban communities with both idle energy infrastructure and strong development potential. Finally, the program has a strategic business development program that will promote specific regional development assets or enhance the competitiveness of Rhode Island.

THE DIVISION'S DIRECT TESTIMONY

A. Bruce R. Oliver
President, Revilo Hill Associates, Inc.

Mr. Oliver filed testimony to address the Company's proposals for revenue decoupling, economic development and the recovery of commodity-related uncollectible accounts expense. In discussing the Company's revenue decoupling proposal, Mr. Oliver noted that only in California was revenue decoupling implemented prior to 2007. Mr. Oliver asserted that NGrid's revenue decoupling plan is focused on providing benefits to the Company and its shareholders rather than its ratepayers. He stated that of the jurisdictions that have it, those plans are noticeably different than what is being proposed in Rhode Island. He noted that as of the date of the filing of his direct testimony only thirteen electric utilities in eight states have full decoupling mechanisms in place and six of those are in California and Maryland. He stated that currently there are two revenue decoupling influences already in place for the Company: for both Medium and Large C&I Customers they have monthly customer and demand charges, in addition, the current rate proposal is premised on sales forecasts that have been adjusted to account for anticipated impacts of DSM programs.

Mr. Oliver pointed out that revenue decoupling will not reduce rate volatility. He cautioned that if the Commission approves the Company's proposal, it should put a cap on adjustments like Maryland that has a ten percent (10%) cap on adjustments. He also advised the Commission to question the efficacy of implementing interim rate adjustments which is inconsistent with the proposed use of a uniform cents per kWh reconciliation adjustment for all rate classes. He noted that the proposal to recover solely through charges set based on kWh deliveries would be unfair to Medium and Large Industrial customers because they pay a large portion of their bill to customer and demand charges. Mr. Oliver opined that revenue decoupling is not necessary to ensure the pursuit of energy efficiency because those measures are customer decisions, not utility decisions.

Mr. Oliver warned that the Commission should be concerned with the impacts of computing a single uniform rate for all classes, the absence of explicit consideration of the impacts of major electrical outages and out-of-period billing adjustments, lack of sufficient detail for determining revenue requirements associated with plant additions since the last rate case, and requirements for increased review of reconciliations without assurance of reduced frequency of rate case filings. He expressed concern that customers in small rate classes could be adversely impacted by reconciliations that are performed on a class-by-class basis. He pointed out that NGrid would be reimbursed for lost sales resulting from power outages regardless of the reason for the outage.

Mr. Oliver noted that the allocation of the net CapEx adjustments to revenue requirements among rate classes is not reasonable and appropriate and may cause distortions within the determination of class revenue requirements. He identified two problems with the annual net inflation adjustment as the productivity offset being a judgmental estimate and the broad indices of inflation as not necessarily supporting reasonable or accurate depiction of distribution O&M cost increases of Rhode Island operations. Mr. Oliver stated that the net CapEx adjustment is not reasonable in that it defers a determination regarding the prudency of capital additions until the Company's next rate case and thereby presupposes rate determinations are to be made before costs of capital additions are evaluated for prudence. He stressed that the standard of review is prudent, used and useful. He noted that if the Commission found a net CapEx adjustment appropriate it could allow for one without revenue decoupling.

Mr. Oliver disagreed with the Company on four points. First he noted that decoupling is not necessary for utilities to encourage conservation and energy efficiency. He also stated that decoupling cannot be relied on to reduce volatility in rates for electric service. Mr. Oliver indicated that the Company provided no support for its assertion that the decoupling plan will reduce the frequency of rate cases or lower costs of regulation. Finally, Mr. Oliver stressed that all revenue decoupling mechanisms are not the same and that this particular proposal significantly reduces the Company's risk more so than in Docket No. 3943, NGrid's recent gas rate case.

Mr. Oliver indicated that revenue decoupling cannot be relied on to reduce the frequency of rate cases because the Company should file one every three or four years to review its revenue requirements, COS and structure of charges to make sure they are reasonable and equitable. He pointed out that revenue decoupling will not reduce regulatory expense because there will be a number of reconciliation hearings required. There were other concerns with the Company's proposal also pointed out by Mr. Oliver, including the lack of reference of accrual of interest on deferred revenue balances and the significant increase in the number of annual filings in the second half of the year. While energy efficiency will not be impacted, he stated that the proposal will adversely impact customer-initiated energy efficiency by distorting customer perceptions of the relationship between energy usage and monthly billed charges for electric service.

Mr. Oliver recommended that the Commission reject the Company's revenue decoupling proposal as inappropriate and inequitable finding that it represents an unjustified departure from traditional ratemaking practices and principles. He suggested that if the Commission approves the proposal, then it should limit it to an annual reconciliation of actual and approved base-rate revenue and not allow for adjustments to revenue targets between rate cases, that it bar speculative adjustments and that it limit the annual rate impact from the adjustments to ten percent (10%) or less, and finally that the Commission reduce the Company's authorized return on equity to reflect the lower risk to the Company.

As for the Company's economic development proposal, Mr. Oliver recommended that the Commission not approve the funding for this program until such time as NGrid provides detail with the appropriate cost/benefit analysis. His concerns with this program include the lack of a cost/benefit analysis, the lack of a proposal for regulatory oversight, the lack of substantial details on costs the Company would incur for its activities, the lack of safeguards to prevent diversion of funds, the lack of specifics regarding the timely stimulation of the Rhode Island economy and the lack of information regarding the economic development needs of Rhode Island. Mr. Oliver also supported Mr. Gay's recommendation for a bad debt ratio of 0.71%. He noted that in Docket No. 3943, the Commission did not approve the proposed reconciling mechanism and that it should do the same in this case.

B. David J. Effron
Consultant Specializing in Utility Regulation

Mr. Effron filed testimony regarding the Company's revenue requirement and the distribution adjustment provision included in the Company's proposed tariffs. He calculated the revenue requirement to be $242,384,000 with a revenue deficiency of $26,841,000 which is 12.459% of current revenues. He also recommended that the Commission reject the Distribution Adjustment Provision proposed by NGrid. He identified the elements of the COS as operation and maintenance expense, depreciation, taxes other than income taxes, income taxes and return on rate base.

Mr. Effron made a number of adjustments to the operation and maintenance expenses proposed by the Company. He reduced the incentive compensation by fifty percent (50%) because that is the amount that the Company bases on attainment of financial goals. He reduced the contracted hiring requirement by $1,363,000 noting that minimum staffing requirements should allow the Company to reduce the amount spent on outside contractors. He eliminated the adjustment for the two customer assistance advocates because NGrid did not establish that the positions are necessary or that the Company is the appropriate party to fill the role of consumer advocate. Mr. Effron recommended that rate case expense be amortized over a five (5) year period as opposed to the Company's request for a two (2) year period. He eliminated $1 million for the economic development program because he noted that it is not necessary for the provision of distribution service and not a critical function of the electric distribution utility, and if the program is implemented, it should pay for itself in the form of load growth and/or retention of current load.

Mr. Effron reduced uncollectible account expense by $894,000 to reflect elimination of transmission revenues from revenue base. He also disputed the Company's proposal for a reconciliation mechanism for delivery related write-offs as contrary to sound ratemaking policy noting that it would reduce or eliminate incentives to control costs authorized under standard ratemaking practice. Mr. Effron also reduced the storm fund accrual because it has a surplus of over $21.5 million and reduced the storm damage expense by $2,001,000 because the five (5) year average of storm damage costs is much less than the 2008 O&M expense. The injury and damages expense was reduced by $2.5 million by Mr. Effron as not recurring because it is associated with the potential settlement of a litigation matter from 2004. He also reduced outside legal expense by the costs attributable to the Constellation litigation as they will not be incurred prospectively. A load response credit of $300,000 was included to reflect the ISO load response credit received in 2009. Mr. Effron recommended reducing merger synergies and costs to achieve by $1,176,000. Mr. Effron adjusted depreciation expense to reflect his adjustment to plant in service. Taxes other than income taxes were adjusted to entail the elimination of wages and salaries and the municipal tax expense of $883,000 refunded from the City of Providence.

Mr. Effron adjusted rate base by $20,222,000 because he noted that from January to July 2009, gross additions to plant in service averaged approximately $4 million per month. This calculation resulted in a projected plant in service of $1,191,604,000. Mr. Effron also forecasted retirements of $6,458,000. Mr. Effron calculated a reduction of $688,000 to the pro forma rate year depreciation expense related to the adjustment to plant in service. He calculated an average rate year depreciation reserve balance of

$518,992,000 which is approximately $2.3 million greater than the balance projected by the Company. As for cash working capital, Mr. Effron proposed two modifications. The first was to remove the Contract Termination Charge ("CTC") expense because it is recovered by a separate fully reconciling rate mechanism which would result in a reduction of $371,000 to Cash Working Capital ("CWC"). The second modification is to modify the CWC percentage assigned to municipal taxes in the calculation of the CWC allowance to be consistent with the gas case, Docket No. 3943, of -8.82% which further reduces CWC by approximately $8.5 million.

Mr. Effron projected a rate year balance of Accumulated Deferred Income Taxes of $119,964,000 which is approximately $6.9 million greater than the rate year balance forecasted by the Company. He proposed a rate of return of 7.78% for a total of $45,537,000. He recommended that the Commission not approve the distribution adjustment provision noting that it was previously based on the 2000 Settlement Agreement for the purpose of allowing for the adjustment of rates for exogenous events that may occur during the rate freeze period.

C. Matthew I. Kahal
Consultant specializing in Economics

Mr. Kahal provided pre-filed testimony to address the proposed rate of return and return on equity. Mr. Kahal noted that the 11.6% equity return proposed by Mr. Moul is a significant increase over the currently authorized 10.5% cost rate. He recommended an overall rate of return of 7.78% with an ROE of 10.1% and a capital structure of 52.3% total debt and 47.5% common equity and 0.2% preferred stock which is in line with NEC's extremely favorable business risk profile. He pointed out that a reasonable range of common equities for electric utilities would be 45-50% and asserted that Mr. Moul did not justify the 50% equity ratio figure that he proposed.

Mr. Kahal disagreed with Mr. Moul's cost rates for long and short term debt. He recommended 1.6% as opposed to Mr. Moul's 2.5% for short term debt and 6.10% as opposed to Mr. Moul's 6.79% for long term debt. Mr. Kahal relied primarily on the DCF model when determining the cost of equity. He used the average from two proxy groups, one composed of gas companies and one composed of electric companies. Mr. Kahal maintained that NEC is a low risk utility which is expected to continue into the foreseeable future and his proposal does not have an adjustment for an RDM mechanism because the Division does not support RDM.

Mr. Kahal noted that capital cost trends show a downward trend at least for long term securities. He noted that yields on Treasury notes have trended downward and that the Consumer Price Index ("CPI") shows zero inflation so far in 2009. He indicated that low inflation is a crucially important force at work that tends to lower the utility cost of capital and that federal tax policy is also favorable in terms of impacting the cost of equity. He maintained that the Discounted Cash Flow Method ("DCF") can capture cost of equity implications like inflation and federal tax policy.

In discussing Mr. Moul's proposal for a 50/50 capital structure, Mr. Kahal noted that this proposal is above the industry average and that the lower the business risk, the less equity that is needed in the capital structure. He pointed out that Value Line has an industry average equity ratio of 48% but the actual percentage for 2008 was 45.3% with a forecast of 47% for 2009 and 47.5% for 2010. His calculations for his two proxy groups for the average equity ratio were 47.4% for gas utilities and 44.8% for electric utilities.

Mr. Kahal indicated that his capital structure accepts Mr. Moul's recommendation for 4.98% for short term debt and 0.19% for preferred stock. He increased his percentage of long-term debt to 52.67% to account for the 2.5% reduction he made to the Company's equity ratio for his proposed ratio of 47.5%. Mr. Kahal based his recommendation for a 1.6% cost of short term debt on the fact that the actual short term debt rate experienced by NEC was below 1% this year. The 1.6% he recommended is the twelve month average ending June 2009. For long term debt, Mr. Kahal noted that since interest rates were declining, 6.0% is more reasonable but he recommended 6.1%. Mr. Kahal questioned whether it was reasonable for NEC to issue the planned $512 million of long term debt all in one type debt instrument.

When discussing business risk, Mr. Kahal indicated that utility stocks are very low risk. He noted that credit ratings for NEC are strong and NEC's risk profile was described by S&P as excellent and by Moody's as a low business risk profile. He chose two proxy groups with similar or slightly riskier profiles than NEC. He challenged Mr. Moul's seven companies for all having RDMs, some having non-utility operations, some have extensive nuclear power operations and most being vertically integrated.

When Mr. Kahal calculated his proposed ROE he emphasized the DCF model and also considered the CAPM. He noted that two factors determine cost of equity: fundamental conditions in capital markets and business and financial risks of the company. He described the DCF model as widely relied upon by the regulatory community, and that the method is market-based, transparent and understandable. He noted that since the DCF model can only be applied to publicly traded companies, he needed a proxy group since NEC is not publicly traded. He used two proxy groups, one of gas utilities and one of electric utilities. He justified using a gas proxy group by stating that there was not a robust group of pure-play publicly traded electric distribution companies. He pointed out that the gas utilities he chose were similar to NEC per S&P's new ranking for business risks of utility and power companies. Mr. Kahal noted that the vertically integrated companies that Mr. Moul used were in a totally separate group that excludes NEC.

Mr. Kahal concluded that the acceptable range of equity cost for the gas proxy group using the DCF model was 9.7% to 10.2%, with the average being 10.0%. The average ROE for the companies in his electric proxy group was 10.2% with the range being 9.7% to 10.7%. Mr. Kahal also evaluated the cost of equity using the CAPM and found that for his proxy companies the range of ROE was 7.5% to 9.6% with the midpoint being 8.6%. Mr. Kahal noted that the CAPM results confirmed that his DCF recommendation was not unduly low. To arrive at his 10.1% recommendation, he used the average of the midpoints for his gas proxy group and his electric proxy group. He also looked at other NGrid companies which average about 10% and have been able to operate successfully and maintain solid credit ratings with those returns. He pointed out that his analysis does not assume RDM. He recommended that if the Commission approves the Company's RDM proposal, it should lower the cost of equity.

Mr. Kahal identified a number of problems he found with Mr. Moul's methods and analysis. The first problem he cited was that Mr. Moul used all electric utilities with RDMs in his proxy group and that does not adequately reflect NEC. Furthermore, he noted that the NGrid RDM proposal is more ambitious and that two companies in his proxy group, Pepco and Idaho Power have a partial or limited RDM. He also pointed out that three of the companies in Mr. Moul's proxy group have large nuclear investments and five of the companies are vertically integrated and are located on the west coast. Mr. Kahal stated that there was no support for Mr. Moul's conclusion of a 6% growth rate contained in his DCF analysis. He stated that Mr. Moul should have used a 5.0% growth rate, which would have caused his ROE to drop to 10.0% because the August actuals lowered the average of the measures he used to 4.66%.

Mr. Kahal disputed Mr. Moul's use of a leverage adjustment as contrary to accepted DCF theory as well as to regulatory practice because NEC is no riskier than any company in the proxy group. He claimed that Mr. Moul used an improper adder because he included a leverage adjustment in his CAPM study. Mr. Kahal noted that if Mr. Moul had incorporated 2008 data into the long-term historic average and used a lower equity risk premium adjusted by 88% for NEC's low risk and 6% for single A bond yield, he would have computed a 9.59% risk premium cost of equity as opposed to the 12% that he obtained.

Mr. Kahal also noted that Mr. Moul added two adjustments to his CAPM analysis, leverage and size, which lead him to overstate the cost of equity estimate, and that he should have selected a lower overall stock market risk premium. Without the two adjustments, Mr. Moul's 11.8% would have been 10.6%. Mr. Kahal dismissed Mr. Moul's use of comparable earnings method as pure accounting results with no market data employed.

D. Lee Smith
Managing Consultant and Senior Economist
LaCapra Associates

Ms. Smith provided testimony regarding her review of the reasonableness and appropriateness of the allocation of costs from affiliates to NEC. She recommended reduction in Accounts 583 – GIS Survey Costs, and 588 – Transformation Expense by $2.3 million and $0.8 million, respectively, because these expenses were not justified and were not recurring. Ms. Smith noted that expenses billed by the Service Company in 2008 were 48% of O&M expense. She indicated that the only way to judge if Service Company costs are reasonable is by judging them against other utilities, and that the Company did not provide any evidence that these costs could not be acquired for less elsewhere. She also pointed out that since most Service Company employees are in New York, they are paid at a New York rate which is approximately 6.4% higher than the average pay level in Rhode Island. Ms. Smith also noted that costs in a number of the Company's accounts have risen at a much higher rate than is normal for comparable utilities.

Ms. Smith compared O&M spending in FERC accounts and compared the percentage cost increases by account to determine whether the increases were much higher than for comparable utilities to see if the level of expenses were prudent and normal, and then compared the costs on a per MW and per customer basis. She removed CTA because they are not normal expenses and removed uncollectibles and DSM because individual utilities do not have much control over these costs. Her comparison of costs revealed high increases from 2007 to 2008 particularly in Accounts 583 and 588.

With regard to Account 583, she noted a $2.3 million charge attributable to the GIS Survey which began in 2005. She noted that this does not appear to be an on-going expense and recommended that it be disallowed. The increase in Account 588 was primarily for the Electricity Distribution Transformation Program. She identified three problems with this program in addition to the lack of cost analysis performed to justify it. Those problems were with the lack of demonstration that it is worth the cost, that its performance by the affiliate is the least cost and that the company will continue spending the same amount in the rate year. She recommended disallowing fifty percent (50%) of the Company's request or $0.8 million.

E. Dale E. Swan, Ph.D
Senior Economist and Principal
Exeter Associates, Inc.

Dr. Swan provided testimony regarding his evaluation of the reasonableness of the embedded, class cost-of-service study filed by NEC, as the appropriate allocation of the allowed jurisdictional revenue requirement among the customer classes based on costs of service and other general rate design considerations, and his evaluation of the proposed rate design. He noted that classification of most distribution plant and related costs above the meter as demand-related, are appropriate.

Dr. Swan discussed three errors he observed with the Company's Class Cost of Service Study and provided the results of the Division's study which corrects these errors. The correction was to the allocation of line transformer costs and associated O&M based on the number of customers. Dr. Swan noted that the Company's allocation of these costs cannot be proper because it makes no allowance for the different sizes of customers in terms of their loads. He pointed out that the combined residential classes receive 94% of these costs if based on number of customers. He recommended that line transformer costs and associated O&M be classified as demand-related and based on its share of the average of primary and secondary non-coincident peak percentage sectors.

Dr. Swan's second correction was to the $4.3 million of uncollectible costs that he recommended should be allocated to all classes and viewed as a general cost of doing business. He indicated that requiring all residential customers to pay for bad debt is unfair to those that pay their bills on time. Lastly, he asserted that allocation of most of the $5.4 million in customer service and information expenses on the number of customers is incorrect and should be allocated on the basis of energy use at the meter. Dr. Swan concluded that with his changes to the COS study, the residential rate of return would increase from 1.29% or 57.8% of the jurisdictional average to 2.46% or 110.3% of the jurisdictional average.

Dr. Swan commented that Mr. Gorman did not pay sufficient attention to rate continuity or gradualism in his spread of the Company's proposed total jurisdictional revenue increase. He developed a proposed spread, the first step being to cap the Lighting and Propulsion classes at twice the jurisdictional percentage increase or at 58.8%. He recommended that the approximate $2.05 million revenue shortfall resulting from this be split up to all other classes on the basis of their revenues at equal rates of return. He also suggested that the entire amount of the A-60 subsidy, $4,795,000 be spread among all classes and not just solely allocated to the A-16 class.

Dr. Swan proposed an alternative spread of NGrid's proposed total jurisdictional increase based on his COS study that mitigates the impact of the $4 million in transmission revenue shift by 50%, provides a more equitable spread of the cost of the A-

60 subsidy among all customer classes, and accounts for all of the revenue changes. He also proposed limiting the increase in the A-16 customer charge to between $1.00 and $1.25 and limiting the increase to the C-06 customer charge to $2.00. He recommended spreading out the increases imposed on the B-62/G-62 customers over three to five years. Dr. Swan also proposed that all SOS Administrative Costs Factors be allocated on SOS energy deliveries which would result in an equal SOS Administrative Cost Factor for all customers.

G. Bruce A. Gay
President, Monticello Consulting Group, Limited

Mr. Gay provided testimony to discuss his assessment of NGrid's management of accounts receivable and to determine if it has contributed to the growth in net charge-offs because the Company is asking the Commission to shift the risk of growth in this area from the shareholders to the ratepayers through its proposed adjustment processes. Mr. Gay disagreed with Mr. Wynter's assertion that growth in uncollectibles is due to commodity prices and economic factors. He performed a full review and analysis of NGrid's performance regarding charge-offs. Mr. Gay pointed out that the increase in commodity prices are not the primary factor in the increase in uncollectibles. He stated that in spite of the variation in commodity prices during 2007 through 2009, average bills for customers did not match the percentage increases or decreases in commodity prices; therefore, other factors must explain some of this variation. He indicated that he did not believe that the increase in commodity prices caused a higher percentage of customers to be unable to pay their bills. He noted that economic conditions may have some impact on charge-offs but those charge-offs were increasing prior to the downturn in the economy.

Mr. Gay maintained that the primary factor driving charge-offs is NGrid's management of it delinquent portfolio and active accounts. He noted that past due balances are allowed to grow to unmanageable amounts and conventional strategies for collection are ineffective. He stated that the larger the balance, the more difficult for the individual customer to manage and the harder it is for the Company to collect. Mr. Gay pointed out that since the Company is offered significant regulatory freedom in its collection of commercial and industrial accounts, it should be able to better manage its accounts receivable and charge-off volumes on non-residential as opposed to residential accounts. He pointed out that non-residential account charge-offs are up to about 35% and the average time to shutoff a customer was approximately nine months. He noted that if the Company shut the customer off sooner, it would have saved approximately $1.5 million. He indicated that there are currently more than 8000 non-residential customers with past due amounts of greater than 60 days. He noted that the average past due balance is $3,173 and the total due was $25,650,420. He stressed that for these accounts, the Company only disconnected 78 accounts with a total balance due of $77,782. He maintained that the Company's actual collection and disconnection activity was overwhelmingly disproportionate to the size of the delinquent portfolio.

Mr. Gay also discussed standard residential charge-offs that were approximately 68% of charge-offs in 2008. He stated that many of the accounts could have been terminated prior to the thirteen months past due that the Company waited before it terminated service to 2,138 customers. He noted that the standard residential accounts receivable average balance is $673. He indicated that the Company had threatened disconnection on about 42% but actually disconnected less than 2% of the delinquent customers. He pointed out that in August 2008, the Company started an outbound calling program for customers with past due balances exceeding sixty days and increased disconnection notices from 42% to 73%.

Regarding the protected residential charge-offs, Mr. Gay noted that in 2008, approximately 10% of the charge-offs were from A-60 customers. He noted that many of the accounts could have been terminated sooner but this group is protected from disconnection during the moratorium period and they receive more lenient repayment terms on delinquent balances. He pointed out that the average overdue account is fourteen months overdue. He noted that in the month and a half after the moratorium, the Company issued no outbound calls. He stated that it was not until August 2008 that the Company increased monthly disconnection activity and that collection and disconnection activity is overwhelmingly disproportionate to the size of the delinquent portfolio. Mr. Gay suggested that the Company employ new collection treatment strategies such as assessing security deposits or assessing late payment fees on standard residential customers. He recommended a bad debt ratio for distribution and commodity related service of 0.71%.

<u>H. Richard S. Hahn</u>
<u>Principal Consultant, LaCapra Associates, Inc.</u>

Mr. Hahn filed pre-filed testimony regarding the Company's proposed Inspection & Maintenance Program, the Vegetation Management Program, the Capital Plan, and the Facilities Plan. He recommended that the Company's proposals for a separate surcharge for the I&M Program and the Vegetation Management be rejected. He noted that both are very small relative to overall scale of operations and a separate cost recovery mechanism for the I&M Program is not necessary. He also recommended that the Commission reject the CapEx pointing out that capital additions were 45% higher in 2008 than the previous three years. He stated the CapEx tracker was unnecessary since the proposed 2009 and 2010 spending is in line with 2008 levels, the system appears reliable, and the Company appears to be adequately investing to maintain reliability.

Mr. Hahn stated that the Commission should require the Company to include the level of savings expected as a result of the facilities consolidation in the COS. He expressed concern about the I&M proposal because it lacked sufficient detail about the inspection plan and how this proposed plan is different from what is currently done. He stated that there was no detail about the types of inspections and whether they were visual or something else. He indicated that the Company did not present any evidence that all of the costs of the program are truly incremental. He found it hard to justify the $2 million as being a separate expense component when O&M costs are approximately $164 million.

Mr. Hahn noted that the I&M program does not appear to be a new program and appears to have begun in 2006. He stated that the amount spent does not appear to be the kind of known and measurable change that is normally included as a pro forma adjustment to the historic test year data. He emphasized that system reliability is good and concluded that there is no adequate justification to increase spending on I&M.

Mr. Hahn also addressed the Company's proposal for Vegetation Management, and his comments were the same as they were for I&M. He found the incremental costs to be small relative to overall operation and thus there was no need for a specific tracking cost recovery mechanism. He stated that the scope of plan is within the purview of management, that the company does not need Commission approval to implement the plan and that it appears that the Company has been conducting these activities all along. He found no adequate justification to increase spending on these activities. He also found the amount to be spent speculative and therefore, not known and measurable.

Mr. Hahn noted that other than the claim that some equipment is old, the Company's capital plan does not support its claim that the system needs huge investment. He pointed out that spending projections for the next two years are the same as recent years. Mr. Hahn stated that the depreciation study proposes to decrease the depreciation rate from 3.53% to 3.35% which indicates that the distribution assets have a longer life than previously determined. He maintained that this contradicts NGrid's assertion that there is a need for accelerated replacement. Mr. Hahn pointed out that according to information presented by the company, reliability statistics have been improving since 2001. He found this to be further evidence that Company has been adequately investing in the system and providing a high level of reliability. He noted that a summary report of NGrid's reliability performance showed a high level of reliability, that statistics for SAIDI and SAIFI have continued to improve. Contrary to Company testimony, Mr. Hahn argued that the feeder hardener program will be replaced by the new I&M program and that because the last oil-fused cutout has been replaced, there is no continuing need to pursue this program.

Mr. Hahn noted that a review of FERC Form 1 shows that the NEC plant in service is comparable if not higher than other similar utilities and has improved over time. He stated that there was no proof that the spending levels justified implementation of a special cost recovery mechanism. Furthermore, if the 2008 spending level is representative of what is required in the future, there is no need for a CapEx tracker in decoupling mechanism. He also stated that there was no evidence that the Company cannot fund necessary improvements to its delivery system without a separate mechanism. He noted that since the Company plans to issue $512 million in new long term debt to replace $156 million in existing short-term debt and to pay $356 million in cash dividends to the parent company, then it can raise a significant amount of capital, if needed. If a special mechanism is not approved, the Company can issue new debt and equity and file another rate case. He also found that there were no expected savings shown that the Facilities Plan will accomplish and recommended that the Commission require the Company to include an amount of savings in the COS.

INTERVENOR'S DIRECT TESTIMONY

A. John Farley
Executive Director
The Energy Council of Rhode Island

John Farley provided testimony regarding the proposed amount of increase in revenue requirements, the appropriateness of the Cost of Service Study with respect to the current G-62 and B-62 rate classes, the reasonableness of the proposed new rate designs for G-32 and B-32, the proposed transmission rate design, the other adjustment factors, and the revenue decoupling proposal. He disagreed with NGrid's revenue requirements. He maintained that the increase in the revenue requirement of 30% is excessive noting that the population has declined, the number of jobs has declined, and Rhode Island has the fourth highest industrial price for electricity in the US. He noted that these core indicators show that the 30% increase cannot be supported.

Mr. Farley also disagreed with NGrid's COS study. He noted that the COS increases allocate distribution revenue of the B-62 and G-62 classes from $5.4 million to $10 million. He pointed out that rate base allocated to the G-62 class increases from $14 million to $22 million even though MW sales have decreased about eight percent (8%) and demand billing units have only increased by one percent (1%). He stated that the Company has shifted costs from the Lighting and Propulsion class to the G-32 and G-62 classes resulting in the B-32, G-32, B-62 and G-62 classes absorbing more than $1 million from the Lighting and Propulsion classes. He stated that even though Mr. Gorman treated the B-32, G-32, B-62 and G-62 classes separately for the COS Study, he combined them for the purpose of revenue allocation resulting in huge increases for the B-62 and G-62 classes.

Mr. Farley also disagreed with NGrid's rate designs for the G-32 and B-32 classes. He noted that the newly proposed G-32 rate results in large increases to those currently served in the G-62 class who have typical peak demands higher than 8.4 MW. He pointed out that the new B-32 rate increases the demand charge placed on on-site generation for current B-62 customers of 130% and that the bill impact on the current G-62 customer using 500 hours per month with over 8.4 MW will be over a 58.7% increase. He noted that the G-32 rate results in the size of the distribution rate growing as the customer grows. He noted three reasons why the proposed G-32 rate is contrary to good ratemaking: (1) the energy rate is not cost-based (2) it results in excessive rate impacts to the current G-62 customers and (3) it discourages economic growth and development. He stated that the energy charge hurts efficiency and economic growth. He recommended that the Commission order the Company to redesign the proposed combined G-32 and G-62 rate so that those with loads of greater than 8 MW do not experience more than one and a half times the average distribution rate increase for the rest of the customers in combined classes and if this is not possible, then to leave the G-62 rate separate without a per kWh energy charge. He also proposed the elimination of backup rates maintaining that they are an impediment to full development and the procurement of cost effective distributed generation and combined heat and power.

Mr. Farley supported NGrid's transmission rate design which proposes to allocate these costs based on each rate class's contribution to the Company's monthly peak instead of charging customers a transmission base charge which differs by class and allocating a per kWh charge to each class to adjust for over and under recoveries. He disagreed with the other adjustment factors and stated that per kWh adjustments should all be eliminated from the bill and be built into the distribution rate structures each year to ensure that they are allocated to the rate class using COS allocators.

Finally, Mr. Farley opposed NGrid's revenue decoupling proposal noting that it is a permanent and automatic future year rate setting apparatus. He described it as more unfair than the plan proposed by the Company in Docket No. 3943 and stated it would weaken regulatory oversight. He identified a number of reasons that the proposal would be detrimental to ratepayers including that NGrid will no longer have the burden to prove that capital investments are prudent, used and useful but rather that ratepayers will have to show that they are imprudent. He also noted that ratepayers will no longer reap the benefits of good management because rates will be automatically reconciled. Further, he stated that the plan is based on forecasted data so ratepayers will pay for projected future costs now. He explained that automatic rate adjustments will result in rate increases without any required review of the actual expenses or actual earned returns on capital. Finally, he indicated that the proposal transfers risk from the Company's shareholders to its ratepayers. Mr. Farley stated that if the Commission approves the plan, then it needs to change the allocation method for reconciliation so that it is based on COS allocators rather than on kWh consumption and that the amounts to be collected should be built in the rate design for each class and not simply be collected using a per kWh rate adjustment.

B. Mark Newton Lowry, Ph.D.
President, PEG Research LLC

Mr. Lowry's testimony was in support of NGrid's revenue decoupling proposal. He noted that the true up approach to decoupling is the best practice because it encourages the full range of measures that can promote clean energy. He noted that the true up plan has two components: the RDM that makes a regularly scheduled sequence of rate adjustments that cause a company's actual revenues to track its approved revenue requirement more closely and the RAM which adjusts the revenue requirement between rate cases, generally on an annual basis. Mr. Lowry noted that decoupling alone cannot induce utilities to be aggressive proponents of DSM and DG but that they also need incentives to encourage them. He identified the additional benefits of decoupling, noting that relief from the financial impact of declines in sales per customer will result. Additionally, he stated that the automatic compensation for fluctuations and secular declines in system use can increase the efficiency of regulation, that the frequency of rate cases can be reduced, that regulatory cost can be reduced and that cost savings can be used to improve other areas.

Mr. Lowry maintained that full decoupling occurs when revenue tracks the revenue requirement closely and is not permitted to deviate due to volume fluctuations caused by weather or other specific sources. He discussed other jurisdictions that use decoupling. He pointed out that utilities operating under revenue decoupling are often leaders in rate design through the implementation of inverted block rates. He stressed that utilities that do not have decoupling plans have incentives to resist changes promoting energy efficiency. He noted that decoupling will remove the utility's disincentive to promote energy efficiency, minimization of peak system use and customer-sited DG. He identified a decline in volumes per customer as a likely problem for NGrid and recommended that the Commission adopt the Company's decoupling proposal.

C. Ali Al-Jabir
Energy Advisor and Consultant Specializing in Public Utility Regulation
Brubaker & Associates, Inc.

Ali Al-Jabir provided testimony on behalf of the Navy regarding the Company's class cost of service study ("CCOSS") and proposed revenue distribution. Mr. Al-Jabir stated that the Company's CCOSS classified the investment in distribution line costs in Accounts 364-367 as entirely demand-related which is inconsistent with cost causation and generally accepted cost allocation methodologies. He suggested that the Commission require a study of this. Mr. Al-Jabir stated that economic development costs should be allocated to all customer classes instead of just the commercial and industrial customers. He proposed, should the Commission reject this recommendation, that it order any reductions to the revenue requirement be allocated to the C&I Large Demand class and if the reductions were more than necessary to bring the C&I Large Demand class to its cost of service, then the excess be given to all rate classes.

Mr. Al-Jabir stated that if a class produces a rate of return above the system average, then that class is paying part of the costs attributable to other classes who produce below-system average rates of return. He stated that if a class produces a rate of return below the system average, then the revenue provided by this class is insufficient to cover the costs attributable to it. He identified the CCOSS as important because it is used to assign cost responsibilities to various customer classes. Mr. Al-Jabir indicated that he supports the principle that cost-causation should guide the allocation of costs to the customer classes. He noted that other things like simplicity, gradualism, economic development and ease of administration may also be taken into consideration.

Like Mr. Gorman, Mr. Al-Jabir identified the three steps in a CCOSS. He noted that when rates are based on cost of service, customers receive accurate price signals against which to make their consumption decisions which will affect their decision to use electricity efficiently. He disagreed with the Company's CCOSS with regard to the proposed classification and allocation of certain components of distribution costs, specifically costs associated with investments in Plant Accounts 364-368. He believes that those costs should be allocated on a customer count and demand basis. He also disagreed with the Company's proposal to allocate all of the economic development costs to Commercial and Industrial customers and objected to the proposed revenue subsidy for the Lighting and Propulsion classes because the entire burden of this subsidy would fall on the C&I Large Demand class.

Mr. Al-Jabir pointed out that a number of other states classify and allocate a portion of distribution line costs on a customer basis and recommended that this be adopted by the Commission because it is consistent with cost-causation principles. He noted that NGrid did not perform a Minimum Distribution System study because they claim that they are not routinely performed in Rhode Island. Mr. Al-Jabir believes that the economic development programs benefit all classes by reducing the escalation of electricity rates for all, so the costs of the program should be borne by all. He noted that the relative rate of return for the classes equals 100, so if the revenue collected from the class is less than the COS, then the class relative rate of return index is below 100 and if revenue collected from the class is greater than the COS, then the relative rate of return index is greater than 100.

Mr. Al-Jabir noted that it is not appropriate to assign an entire subsidy to one rate class. He recommended that the Commission seek to maximize the movement of all customer classes to the COS. He stated that if the Commission accepts NGrid's proposal to moderate the rate increase for the Lighting and Propulsion classes, it is inappropriate to assign this subsidy only to the C&I Large Demand class. Should the Commission assign this subsidy only to the C&I Large Demand class, then any revenue reductions should be assigned to the C&I Large Demand class, and if the reduction is more than is needed to bring the C&I Large Demand class to COS, then the excess should be distributed among all customer classes.

D. Shanna Cleveland
Staff Attorney, The Conservation Law Foundation

Ms. Cleveland testified in support of the Company's decoupling proposal. She noted that revenue erosion created by successfully implemented energy efficiency programs creates a disincentive for utilities to invest in energy efficiency and demand resources. She stated that decoupling is advantageous for two reasons: it ensures that the utility's financial incentives are aligned with the public interest and with helping customers use energy more efficiently and it ensures that utilities have timely cost recovery for monies expended on advancing efficiency. She pointed out that even though decoupling is a necessary condition for energy efficiency, it is not sufficient for achieving efficiency. She maintained that while decoupling has no impact on customers' incentive to conserve, it is intended to affect the incentives of the utility.

She indicated that the law requires a utility to promote energy efficiency and reduce consumer consumption and that this is in conflict with the utility's fiduciary duty to its shareholders to maximize profits by increasing consumption. Ms. Cleveland noted that decoupling will cause both the commodity portion and the distribution portion of a customer's bill to be reduced. She stated that every customer who uses less electricity will pay a lower amount if decoupling is implemented. She believes that even though NGrid did not respond to a data request asking for the magnitude of rate impacts of other utilities, such data is available.

Ms. Cleveland stated that decoupling is important for the environment because it is a way to achieve reductions in greenhouse gas emissions and slow climate change. She pointed out that decoupling is also important for legal reasons and consistent with Rhode Island's public policy. She cautioned that denying the Company's decoupling proposal may jeopardize stimulus funding because the American Resource Recovery Act ("ARRA") requires that the state actually implement decoupling. She also supported the

Wiley Center's request that the A-60 class be exempt from decoupling. Finally, she disputed the prior criticisms of NGrid's decoupling plan.

NATIONAL GRID'S REBUTTAL TESTIMONY

NGrid provided rebuttal testimony from the following individuals.

A. John Pettigrew

Mr. Pettigrew filed rebuttal testimony and addressed five specific issues. He disputed Mr. Effron's recommendation to eliminate $1,363,000 of cost associated with union employees noting that NGrid had contracted with the union in order to institute the five year ramp up of capital work in Rhode Island. He stated that this work could not be done without the additional employees. He disagreed with Mr. Effron's and Mr. Hahn's recommendation to eliminate the test year adjustments relating to the proposed I&M program of approximately $2.1 million pointing out that he had explained the program in detail and had shown that the costs are incremental. Additionally, he justified the incremental amount and the proposed reconciling mechanism to recover amounts in excess of $4.7 million by noting the substantial benefit to ratepayers in terms of the high level of reliability that will result by managing the system's assets proactively.

Mr. Pettigrew also disagreed with Mr. Hahn's recommendation to eliminate the $1,985,000 adjustment to vegetation management. This amount accounts for the substantial and permanent change to the vegetation management program that includes two enhancements to the program: a formal hazard tree mitigation program and a contract strategy method. In disagreeing with Mr. Effron's and Mr. Hahn's recommendation to reduce ratebase by $20,222,000, Mr. Pettigrew noted that almost fifty percent (50%) of the assets are over forty (40) years old and more than fifty percent (50%) of poles are older than thirty (30) years. He indicated that the I&M program is designed to identify what needs to be replaced based on the technical asset life. He also cautioned that if the Company does not start replacing assets now, there will be a large number that are so aged that the volume to be replaced in the future will be insurmountable or extremely expensive to do all at once and will result in reliability problems. Mr. Pettigrew warned that current levels of reliability cannot be maintained without additional capital investment.

Finally, Mr. Pettigrew provided testimony regarding the amounts charged to the Company by the Service Company through Account 583, used to record costs of updating data in the GIS system which he claimed are recurring, and Account 588, used to record costs associated with the Transformation Program which he claimed will inure to the benefit of customers in future rate cases.

B. Rudolph Wynter

Mr. Wynter provided rebuttal testimony to dispute Mr. Gay's testimony that commodity prices do not contribute to the increased level of uncollectible write-offs and noted that the external factors of which Mr. Gay spoke were in addition to rising commodity prices. He disputed Mr. Gay's charts as not being proof that commodity costs have little correlation to net write-offs. He again noted that the winter moratorium continues to contribute to the arrears that accumulate during the winter months for NGrid's customers. Mr. Wynter made a number of points to address Mr. Gay's assertion that test year write-offs would have been dramatically less had the Company accelerated its disconnection activities on its delinquent accounts since 2007, including the fact that since 2004 disconnection activities have doubled and that outbound calls and field collection activities have increased. He pointed out that the Division's proposed rate of 0.71% would not allow for consideration of customer-specific circumstances and that absent the Company's significant efforts to ramp-up collection activities, the uncollectible ratio would have been higher.

C. Susan F. Tierney, Ph.D

Dr. Tierney filed rebuttal testimony to address the comments made by Mr. Oliver and the intervenors. She disagreed with Mr. Oliver that decoupling is not necessary for a state like Rhode Island to achieve its broader energy efficiency goals reiterating her prior testimony and referring to the testimonies of Ms. Cleveland and Mr. Lowry. She stated that Mr. Oliver's testimony fails to recognize the barriers to implementation of cost effective energy efficiency and NGrid's unique relationship with its customers that can be leveraged to overcome these barriers. She pointed out that ratemaking policies are designed to better align financial incentives of the utility with the economic interests of its customers. She noted that regardless of the source of the energy efficiency action, traditional ratemaking reductions in energy use adversely affects the utility's financial interests by lowering its distribution revenues.

Dr. Tierney noted that the other forms of revenue decoupling currently included in rates are not sufficient incentives for the Company to pursue all cost-effective energy efficiency because at least seventy percent (70%) of revenues come from per kWh or per kW charges that would be reduced with the implementation of energy efficiency measures. She disputed Mr. Oliver's assertion that revenues from demand charges remove a utility's disincentive to promote energy efficiency noting that increased energy efficiency could result in lower demand-related revenues. She pointed out that once rates are set by the Commission, the incentive to increase sales is the same regardless of whether the rates reflect anticipated reduction in sales from energy efficiency. Dr. Tierney also disagreed with Mr. Oliver's conclusion that revenue decoupling would reduce incentives for energy efficiency because it would distort customer perceptions of the relationship between energy usage and monthly billed charges for electric service by noting that any offsetting effect on rates would be inconsequential and would not distort customers' incentives to undertake energy efficiency.

Dr. Tierney asserted that Mr. Oliver did not consider the significant financial savings that would result to customers that reduced their energy commodity costs which makes up the largest component of their monthly bill. Dr. Tierney admitted that the Company's revenue decoupling proposal goes beyond traditional revenue decoupling mechanisms, which she noted would not be well matched with the Company's current operating, market and financial circumstances. She noted that considerations such as the financial climate and the Company's aging infrastructure require a more dynamic ratemaking mechanism to allow the revenue requirement to adjust more actively to changing conditions in order to avoid frequent rate case filings necessary to avoid continuously falling behind in efforts to recover costs and an allowed rate of return. Dr. Tierney stated that Mr. Oliver fails to appreciate the circumstances of the Company that form the basis for the RDR Plan.

Dr. Tierney also addressed the testimony of Mr. Farley, disagreeing with his suggestion that the RDR Plan is inconsistent with the requirements of the 2006 law. She notes that the law gives the Commission the discretion to order a rate making adjustment clause. She also disagreed with Mr. Farley's assertion that the proposed RDR Plan amounts to an automatic rate case that circumvents the role of the Commission by pointing out that the RDR Plan is designed to ensure that NGrid collects no more or less than its approved revenue requirements. She again stressed why the adjustments to the RDR Plan are necessary and that they would require Commission approval. She reiterated that the additional ratemaking elements of the RDR Plan will allow for more timely recovery of the Company's expenses and investment, and would reduce regulatory lag. Dr. Tierney agreed with Mr. Oliver's assertion that the Company's filing does not include any analysis of rate impact that would result if the Commission approved its RDR Plan. She cited a study authored by Pamela Lesh for the Regulatory Assistance Project ("Lesh Report") to support her assertion that the decoupling adjustments would be small or even miniscule.

In disagreeing with Mr. Farley's assertion that the RDR Plan would adjust rates in a way that predetermines a beneficial outcome for NGrid, Dr. Tierney noted that the proposal is designed to address factors that would prevent the Company from recovering its cost of providing service resulting from regulatory lag and the increase in investment costs. She also disputed the allegation that the RDR Plan shifts the risks from shareholders to ratepayers and stated that the RDR Plan introduces a greater sharing of the risks associated with variations in customer loads, and described the elimination of the variations as a form of insurance for customers. She described the risk to customers as paying higher than allowed revenue requirements that could result should the Company spend less than what is embedded in rates, higher than normal economic activity or abnormal weather.

Dr. Tierney disagreed with Mr. Oliver's assertion that the RDR Plan would provide the Company and its shareholders with greater assurances of revenue collections and earnings regardless of performance by pointing out that the Company would still face risk due to factors such as cost of capital, actual operating and maintenance costs and regulatory lag. She indicated that even with the inflationary and net CapEx adjustments, regulatory lag would not be eliminated nor would there be a guarantee that the net CapEx adjustments would be sufficient to offset actual operations and maintenance costs increases. Dr. Tierney again stressed that Commission approval is still necessary prior to the recovery of any net CapEx adjustment.

Dr. Tierney indicated that the Company's proposal would allow for a benefit to customers because it would allow for the flow back of money to customers if the Company made prudent capital investments that were less than the amount embedded in rates. She defended her proposed offset to inflation as a heavily informed multistep empirical analysis based on her experience and judgment as opposed to Mr. Oliver's description of it as speculative and inappropriate. She disputed the allegation that the documentation of methods and calculations needed to perform the adjustments was not sufficiently detailed noting that she clearly described these calculations in her direct testimony, and such detail was also provided in the schedules attached to the testimonies of Mr. O'Brien and Mr. Gorman.

Dr. Tierney noted that she had reviewed the revenue decoupling and other ratemaking elements of the proxy group relied on by Mr. Moul and noted that the combined ratemaking approaches of these companies were similar if not exactly the same adjustments that complement revenue decoupling in NGrid's proposed RDR Plan.

Finally, with the exception of Mr. Oliver's recommendation that the net CapEx filings include sufficient information to support Commission findings regarding whether the capital addition is prudent, used and useful, Dr. Tierney recommended that the Commission reject all these recommendations.

D. Paul R. Moul

Mr. Moul filed rebuttal testimony to address a number of arguments made by Mr. Kahal. He noted that a sufficient return on equity is important because it signals the level of regulatory support for regulated utilities. In order to attract and retain capital, Mr. Moul pointed out that the rate of return on common equity must be greater than the 10.1% proposed by Mr. Kahal. He challenged Mr. Kahal's proxy group selections as being unreasonable because the groups are not composed of similarly situated electric companies with revenue decoupling in place. Also, he noted that there were issues with the Division's DCF and CAPM analyses and that the Division did not sufficiently account for RP and CE analyses.

Mr. Moul also addressed Mr. Kahal's recommendation of 47.5% common equity by arguing that the gas group ratio is off because short-term debt levels have to be normalized to eliminate the impact of winter gas purchasing. He argued that the electric group ratio was off because that group contained an outlier, Northeast Utilities which has 38.1% common equity. Finally, Mr. Moul pointed out that the Division's equity ratio includes too much debt so that the proposed range of 45 to 50% should be calculated as 50 to 55% with the Company's proposed 50% at the lower end.

E. William F. Dowd

Mr. Dowd provided rebuttal testimony to address Mr. Effron's recommendations on variable pay and union labor commitments. He disputed Mr. Effron's recommendation to eliminate $1,204,000 in variable pay adjustment arguing that it is an integral component of an employee's total compensation. He cautioned that without variable pay, NGrid will not be comparable with others in its field and will not be able to attract and retain qualified employees. He described this as a customer benefit, because it improves financial health of the Company and has a direct effect on cost of equity and debt. He also disputed Mr. Effron's recommendation to eliminate the union labor commitment costs. He noted that the $1,363,000 is necessary because these employees are needed to perform the work on the distribution system as described by Mr. Pettigrew. This work also needs independent contractors because it takes approximately 4-5 years to train and develop a new employee to be fully qualified to work independently.

F. Robert L. O'Brien

Mr. O'Brien provided rebuttal testimony and adjusted the revenue deficiency amount to $63,586,000 as compared to the originally filed amount. He made a number of adjustments to reflect corrections including $20,000 to other revenue, merger related CTA by approximately $400,000, rent expense by $45,987, municipal tax expense by $879,000 and depreciation expense by $9,150. He reduced the rate year average plant to 1,232,477,804, increased accumulated depreciation by $65,940 and reduced ADIT by $21,272.

Mr. O'Brien disputed the Division's recommendation for a five year recovery period for rate case expense indicating that it may result in overlapping recovery if another rate case is filed prior to the end of the five-year amortization. He noted that annual contributions to the storm fund are needed to avoid the negative impacts of large storms pointing out that the storm fund is intended to provide for restoration and recovery of service for customer damage caused by large storms and suspension of the fund will defeat the purpose of the fund. With regard to storm damage expense, he corrected his test year expense to $4,410,401 because of amounts that should have been deferred. He noted that his resulting test year expense was more in line with the costs from 2005 through 2007, which ranged from $2.9 million to $4.1 million.

Mr. O'Brien disagreed with the Division's recommendation to eliminate $2.5 million from the injury and damage expense and use a three year average and noted that an item is not "non-recurring" simply because it involves a reserve amount. He agreed with the recovery of transmission-related uncollectible expense with Commission approval to recover transmission-related uncollectible expense through transmission rates. He requested the Commission allow the Company time to implement procedures consistent with the Commission's decision should the Commission require earlier disconnection of delinquent customers. Further, if the Commission agrees with the Division's recommendation on the uncollectible ratio, he noted that the Company would have to make adjustments taking into account dollars recovered after shutoff, loss of revenue associated with terminated customers and the cost of disconnections.

Regarding merger synergies and CTA, Mr. O'Brien indicated that the Division's recommendation is to reduce the cost of service by $1,176,000 relating to the reduction to CTA allowed through rates. He noted that CTA are incurred on a one-time basis at the outset of a consolidation effort, but produce enduring savings for an entire period. He pointed out that 54% of the total CTA was incurred in years one and two and 46% incurred in years three through ten. He stated that 12% of merger savings was realized in years one and two and the remaining 88% is realized in years three through ten. He stated that the Company is proposing to start a ten year amortization in 2008 to coincide with the period for merger savings; therefore, the Company would have absorbed two years of amortization at $2.1 million per year. He said that NGrid should not be subject to synergy savings proof in the eight year period commencing in 2010 because the Company has included synergy savings in rates to the benefit of customers although not expected until 2011. He asserted that the Division's calculations for accumulated depreciation were not correct. As for cash working capital, Mr. O'Brien alleged that the Division did not provide adequate justification for its recommendations and that the Company's calculations were appropriate and correct.

G. Howard S. Gorman

Mr. Gorman provided rebuttal testimony to address five issues discussed by Dr. Swan. First Mr. Gorman addressed the line transformer costs which he originally recommended be based on number of customers. In his rebuttal testimony, Mr. Gorman recommended that the Commission give equal weight to his allocator and to Dr. Swan's allocator given that these costs are based on the non-coincident peak using the average of the relative class non-coincident peak at primary voltage and the secondary voltages. Mr. Gorman disputed Dr. Swan's recommendation that uncollectible accounts expense be assigned to all rate classes for both delivery and commodity. He noted that this expense is a direct assignment which is preferable to an allocation. Regarding the allocation of customer service and information costs among the rate classes, Mr. Gorman indicated that the Company allocation should be based on the number of customer bills because this more accurately reflects cost causation than Dr. Swan's proposal to allocate these costs based on energy use at the meter.

Mr. Gorman also discussed revenue allocation stating that commodity costs should be included when considering the total revenue change for each class. He noted that by using the total revenue change basis to evaluate rate design impacts, the Company's proposed increases for all classes except Lighting are modest and reasonably close to the average increase. For Lighting and Propulsion, the Commission should accept the Company's proposal because capping those impacts will cause costs to shift to other classes. Finally, he noted that the discount received by Rate A-60 customers should be recovered from all customers, not just Rate A-16 customers, consistent with the Division's recommendation.

H. Julie M. Cannell

Ms. Cannell filed rebuttal testimony to address investor evaluation and perception. She noted that investors provide capital to construct, maintain and replace infrastructure. Ms. Cannell indicated that the terms on which the Company is able to obtain capital has a direct and measurable impact on customers and the amount they pay for distribution service. She stated that the lower the credit rating of a company, the higher their costs of capital. Rates that are too low will adversely affect both the Company and its customers because this will result in an adverse effect on the cost of capital. Ms. Cannell pointed out that because of deregulation, construction cycle, regulatory uncertainty among other factors, the risk of investing in electric utilities is increasing. She noted that the current financial crisis is affecting investor evaluations and that the market is heavily populated by institutional investors who own large blocks of shares and have the ability to react quickly to bad news.

Ms. Cannell stressed that having an investment-grade credit rating is important because the higher the credit rating, the less it costs to borrow. She noted that ratings agencies evaluate the "predictability and supportiveness of regulatory framework" and the "ability to recover costs and earn returns." Ms. Cannell stated that Moody's and S&P have a generally favorable view of the Rhode Island regulatory environment and that Moody's voiced expectations that NGrid's U.S. subsidiaries will see improved earned returns as a result of rate proceedings. She further noted that consistency of regulatory decisions is important.

Ms. Cannell also testified that in thirty-five case decisions over the past year, only six ROE allowances were as low or equal to 10.1 percent nationwide since the onset of the financial crisis. She pointed out that the 8.75% ROE set by the Connecticut Department of Public Utility Control caused a stock decline of 37% representing an example of investor disappointment; whereas an ROE of 11.25% for Tampa Electric resulted in stock price increasing by 35% in the two weeks between the staff recommendation and the commission order. She concluded by indicating that the 11.60% proposed by the Company is fair and reasonable.

THE DIVISION'S SURREBUTTAL TESTIMONY

The Division filed the surrebuttal testimony of the following individuals.

A. Bruce R. Oliver

Mr. Oliver provided surrebuttal testimony in response to Dr. Tierney's rebuttal testimony. He noted that the inequity in the treatment of customers across rate classes represents a major shortcoming of the RDR Plan. He stated that all of the factors that NGrid lists as contributing to the need for annual revenue requirement adjustments are the same as what they have faced in the past and do not warrant a major restructuring of regulatory practices. Mr. Oliver described the revenue decoupling proposal as an attempt to implement a form of alternative regulation that limits the Commission's ability to examine the Company's costs, some of which can be offset by decreases in other elements of its costs. He pointed out that weather fluctuations and changes in economic conditions have greater impacts on variations in annual sales than energy efficiency programs.

Mr. Oliver asserted that NGrid's sales forecast does not project a decline in sales and the slow down of growth is more related to the economy than to energy efficiency programs. He pointed out that the Company did not address tightened consumer budgets, reduced business profitability and limits on access to credit as having an effect on customers' ability to engage in further energy efficiency. He noted that a fundamental characteristic to electric service that the Company doesn't pay much attention to is the affordability of service. He advised that NGrid should prioritize expenditures and trim its budgets like its customers are doing. He stressed that from a ratepayer perspective, revenue decoupling is not superior to traditional ratemaking.

B. David J. Effron

Mr. Effron provided surrebuttal testimony to address the Company's response to his direct testimony. He noted that his adjustment to the incentive compensation should pay for itself. He pointed out that the increase in union staffing should result in a reduction in outside contractor expense. Mr. Effron recommended that rate case expense be amortized over a five year period noting that there has not been a distribution rate case since the mid 1990s. He supported his recommendation that transmission related uncollectibles be eliminated from the pro forma rate year expense because they are not distribution costs of service.

Mr. Effron supported his recommendation to eliminate the storm fund expense by noting that the total storm charges over the course of twenty-seven years has only been $17.8 million. He pointed out that the storm damage expense should be normalized over a period of greater than three years. He indicated that if the Company was able to show that the $2.5 million of injury and damages expense was a recurring event, it would be acceptable to him. He noted that even with the elimination of the expense related to the Constellation FCM dispute, outside legal expenses are greater than in 2007 exclusive of payments to the firm that represented NGrid in the Constellation matter.

Mr. Effron indicated that he still believes that his proposal to reduce the annual amortization of CTA by $1,176,000 is appropriate. He maintained that he continues to support his direct testimony regarding rate year plant in service. He modified CWC to reflect the actual pattern of the municipal tax payment applicable to electric operations based on the calendar year and the actual customer payment lag for electric operations. After his further modifications, Mr. Effron proposed a new revenue requirement increase of 11.93% for a COS of $258,688,000.

C. Matthew I. Kahal

Mr. Kahal filed surrebuttal testimony to address the arguments made by Mr. Moul's and Ms. Cannell's rebuttal testimony. He noted that Ms. Cannell's testimony was limited to discussing investor attitudes and general risk trends. He indicated that she presented no analysis demonstrating that his proposed 10.1% return on equity was insufficient for NEC to meet its financial or utility obligations or to obtain access to capital markets on reasonable terms.

Mr. Kahal was critical of Mr. Moul's failure to update his recommendation in light of the fact that financial markets have improved significantly and the cost of capital has declined since his testimony was filed in the spring of 2009. Mr. Kahal noted that due to the declining trend in corporate long-term debt costs, he updated his original recommendation from 6.1% to 5.6% for the cost of long-term debt resulting in a reduction to the rate of return from 7.78% to 7.54%. He indicated that it is his belief that utilities can issue new debt below 5.6% and this is shown by a couple of other company's recent issuances, particularly Niagara Mohawk Power that issued $750 million of ten year notes at a yield of 5%.

Mr. Kahal asserted that Mr. Moul presented no evidence that the Company will actually use the 50% common equity ratio during the rate year. He stated that the average equity ratio in both of his proxy groups was below 50% and the average for the authorized common equity for each NGrid utility company decided over the past ten years was 46.1% which is below his recommended 47.5%. Mr. Kahal noted that even with the adjustments made by Mr. Moul, his DCF results are unaltered. Mr. Kahal also addressed the leverage adjustment Mr. Moul made to his DCF calculation. He stated that the adjustment is not in any way part of the cost of equity. It is included as additional investor compensation because under standard regulation, book value capital structure and not market value capital structure is used for ratemaking. He noted that no adjustment is needed unless a risk increment for NEC relative to the proxy group can be convincingly demonstrated, and NEC is not risky.

Mr. Kahal also addressed Mr. Moul's CAPM analysis noting particularly that he did not provide persuasive evidence that a size adjustment was necessary. He pointed out that there was no evidence that size is a factor in determining a company's cost of equity and that NEC is not small as it is wholly owned by NGrid. Additionally, he pointed out that Mr. Moul failed to update his calculations.

D. Lee Smith

Ms. Smith filed surrebuttal testimony to address her recommendations with regard to Accounts 583 and 588. She noted that the cost increases in those two accounts are dramatic as compared to prior years with no evidence that the underlying expenditures were designed to result in benefits to ratepayers or even that the 2008 expenditures are reflective of rate year expenditures. She reiterated her recommendation that $2.3 million be removed from Account 583 – GIS Survey because there was no evidence that this expense is recurring and that $0.8 million be removed from Account 588 – Transformation Expense because no documentation was produced to track its benefits.

E. Dale E. Swan, Ph.D

Dr. Swan provided surrebuttal testimony to address Mr. Gorman's rebuttal testimony and Mr. Al-Jabir's testimony. Dr. Swan disagreed with Mr. Al-Jabir's recommendation that a minimum system study be conducted in the next rate case as a basis for classifying a portion of upstream distribution costs as customer related. He agreed with Mr. Al-Jabir that it is inappropriate to allocate to the C&I Large Demand class all of the revenue shortfall that results from capping the Lighting and Propulsion classes at twice the jurisdictional average increases and believes it would be more appropriate to allocate this shortfall among all the uncapped classes on the basis of class revenues at equal rates of return. Dr. Swan did not agree with Mr. Al-Jabir, however, that all disallowed revenues requested by the Company be allocated to this class until they are placed at their cost of service.

Regarding the Allocation of Transformer Costs, Dr. Swan noted that he remains unconvinced that Mr. Gorman's transformer study does anything but allocate transformers on the basis of the number of customers and does not account for the different sizes of customers that use the transformer. He recommended that the Commission allocate all of these costs based on the average of the percentage class responsibilities for non-coincident peaks at primary and secondary voltages. He maintained that there is no direct relationship between the number of customers and the costs of transformers or their maintenance and so the number of customers should not be used to allocate these costs. Dr. Swan reiterated his direct testimony that uncollectible expense should be viewed as a cost of doing business and allocated to all classes on the basis of SOS energy deliveries. He noted that the argument that competitive suppliers will be at a disadvantage if these costs are spread out to all customer classes is not a valid argument because there is little interest on the part of competitive suppliers to service residential loads and NEC has no option of whether to provide SOS to qualifying residential customers.

Dr. Swan again noted that the allocation of customer service and information costs should be allocated on energy use at the meter and not on number of customers. He also recommended that increases to customer charges occur over a period of time and not all at once. He suggested that the Commission consider the proposed reduction in transmission charges when looking at the Large Customer increases, because there the increases will not be that substantial. Finally, Dr. Swan disagreed that back-up rates should be eliminated because that will result in a subsidy to self-generators that will have to be picked up by other retail customers.

G. Bruce A. Gay

Mr. Gay filed surrebuttal testimony to address Mr. Wynter's rebuttal testimony. He noted that many factors besides high commodity prices, such as bad debt, weather, usage and conservation, cause customers not to pay their bills. He stated that the data supports his assertion that charge-off balances for customers did not move in lockstep with changes in commodity prices. Mr. Gay asserted that the Company's charge-offs were increasing years before the current economic downturn and have increased every year since 2004. He pointed out that even when unemployment rates were flat from 2003 to 2007, the charge-offs still increased. He stated that the Company should have implemented a debt mitigation strategy prior to 2008.

He again noted that the Company's collection and disconnection efforts did not keep pace with the aging delinquency and past due balances, especially on non-residential and standard residential customers. He noted other debt mitigation strategies that he had mentioned in his direct testimony. He stressed that only a small fraction of accounts were disconnected. Mr. Gay pointed out that since most of the Company's charge-offs originate on accounts that close voluntarily, it is incumbent on the Company to assure that past due balances are minimized so that when customers close accounts ,dollars at risk are minimized. He asserted that the Company has allowed customers to stay on Step 1 of the payment plans and has repeatedly rolled their delinquent balances into new payment plan. He again recommended that the Company be allowed a bad debt ratio for distribution and commodity related service of 0.71%.

H. Richard S. Hahn

Mr. Hahn's surrebuttal testimony recommended that the proposal for a separate surcharge for the I&M Program and Vegetation Management Program be rejected. He reiterated that both programs are small relative to the overall scale of operations. He noted that the Company does not need a separate cost recovery mechanism. He again recommended that the Commission reject the proposal for a CapEx tracker noting that capital additions were 45% higher in 2008 than in the previous three years. He stated that since the system is reliable and the Company appears to be adequately investing to maintain it, there is no need for a CapEx tracker.

Mr. Hahn questioned the Company's need to inspect utility poles that are less than thirty years old which accounts for 57% of the pole asset base. He noted that a more targeted I&M program based on asset age would be more cost effective. Mr. Hahn stated that the Company did not offer any evidence to suggest that it cannot perform adequate inspections of assets or justification for the proposed increase in spending on I&M activities. He pointed out that the increase to the vegetation management program is not a known and measurable change because the amount spent each year is discretionary. He noted that the Company can control and has historically controlled the amount spent on vegetation management. He stated that the amount should not be used for a pro forma adjustment to historic test year costs because it is not known and measurable.

Mr. Hahn expressed uncertainty that the additional significant increase in capital spending is warranted. He noted that the Company wants to include $20.2 million in forecasted capital additions as an adjustment to test year costs. He stated that he was unsure that all of these additions were necessary. He reiterated his direct testimony that the planned capital budgets of $60 million and $76 million are well below what the unadjusted test year data supports. He stated that if $20 million is included as a test year adjustment, it will increase to $88 million per year and total capital additions would increase to $120 million. He recommended that the Commission reject the claim that a large increase in capital spending is driving the need for an adjustment to test year costs and a CapEx tracking cost recovery mechanism because the Company has not proposed an increase in capital spending over the 2008 test year levels.

INTERVENOR'S SURREBUTTAL TESTIMONY

A. John Farley

Mr. Farley provided surrebuttal testimony to respond to the testimonies of Mr. Effron, Dr. Swan, Mr. Oliver, Mr. Al-Jabir, Mr. Gorman and Dr. Tierney. He addressed six issues. With regard to the revenue requirements, Mr. Farley noted that TEC-RI disagrees with NGrid and agrees with the position taken by the Division. He noted in particular that Mr. Effron's findings and adjustments were well-reasoned and well-supported by his testimony and exhibits. Additionally, he concluded that Mr. Effron's revenue requirement calculations were more consistent with what Rhode Islanders could afford during these difficult economic times.

Regarding the cost of service study, Mr. Farley agreed with the Navy on its recommendation that the Commission require the Company to conduct a minimum system study, that the economic development costs be allocated to all classes on the basis of delivery service revenues and that it is not reasonable to place the burdens of revenue subsidies completely on the C&I Large Demand class. He agreed with the Company's allocation of uncollectible accounts-delivery directly to the classes where those bad debts originated. He agreed with Dr. Swan's recommendation that the costs of the A-60 subsidy should be shared by all customer classes, noting it was consistent with the TEC-RI's position regarding the economic development proposal.

Mr. Farley strongly disagreed with the Division's recommendation to shift approximately $2 million of revenue responsibility in the distribution revenue allocation from the residential class to the C&I Large Demand class. With regard to the increases proposed for the existing G-62 and B-62 rate classes, Mr. Farley noted that increases should be phased in and should consider the principles of gradualism and mitigation of large increases. He agreed with the Company's proposal regarding the allocation of SOS bad debt costs noting that this expense should be directly assigned to the classes that incur those debts. He asserted that the Division's recommendations shift costs from the residential class to the business class in almost every change suggested.

Regarding the proposed rate designs for the G-62 and B-62 classes, the transmission rate design and the other adjustment factors, Mr. Farley noted that the Company did not oppose any of TEC-RI's recommendations. Finally, Mr. Farley maintained that TEC-RI opposed the Company's revenue decoupling plan and supports the findings and recommendations of Mr. Oliver. He reiterated the two points made in his direct examination that the plan weakens regulatory oversight and hurts ratepayers. He pointed out that regulatory oversight cannot be measured by the frequency of filings.

He also noted that while the number of filings will increase, this does not equate to an increase in that quality of the review undertaken. Mr. Farley again discussed the Company's specific proposal and maintained that NGrid has requested a number of cost trackers recently. Citing a paper published by the National Regulatory Research Institute ("NRRI"), Mr. Farley maintained that cost trackers provide benefits to the utility but usually cost ratepayers more money.

Mr. Farley addressed Dr. Tierney's assertion that he does not understand the Company's revenue decoupling proposal by noting that the plan is extremely complicated and sending mixed signals to customers with regard to the impact of revenue decoupling. He also pointed out that nowhere does Dr. Tierney state that energy efficiency prevents NGrid from receiving revenue growth from increased kWh sales.

B. Shanna Cleveland

Ms. Cleveland filed surrebuttal testimony to respond to Mr. Farley's, Mr. Oliver's and Dr. Tierney's testimonies. She stated that Mr. Farley's suggestion that decoupling only results in rate increases is wrong. She noted that it can result in rates going down if there are increases in electricity use. She emphasized that Mr. Farley did not present any evidence to support his assertion that decoupling would cause rates to increase and cited "Rate Impacts and Key Design Elements of Gas and Electric Utility Decoupling: A Comprehensive Review" by Pamela Lesh ("the Lesh Report") to support her claim that decoupling also results in decreases to ratepayers. She alleged that Mr. Farley's assertions are based on speculation while Ms. Lesh's statements are based on actual historical studies. Ms. Cleveland noted that she is aware that regardless of what the Commission approves for NGrid's ROE, the role and function of the annual true-ups proposed by the Company will bring that ROE in line with what has been approved by the Commission.

Ms. Cleveland responded to Mr. Oliver's testimony noting three ways to implement partial revenue decoupling noting that the Company's proposal is a proposal for complete decoupling, not partial decoupling, that goes significantly beyond what Mr. Oliver discussed. Additionally, she noted that the instant proposal addresses the concerns and criticisms of the decoupling proposal that was made by NGrid and rejected by the Commission in Docket No. 3943. She also disputed Mr. Oliver's implication that there is a suggestion that the Commission be compelled by the decisions in other jurisdictions to adopt decoupling.

Ms. Cleveland repeated her prior testimony that annual adjustments of more than one or two percent will be highly unlikely. In supporting the Division's alternative recommendation of a ten percent (10%) cap on the annual adjustment, she noted that the Commission would have the authority to examine the causes or increases that approached the ten percent (10%) cap. In responding to Dr. Tierney's testimony, Ms. Cleveland again reiterated her claim that under decoupling every ratepayer who reduces consumption will experience a decrease in the commodity charge and in the distribution charge. She distinguished between rates and bills noting that reductions in consumption will cause a decrease in bills. Finally, she cited a California study that she asserted supports Dr. Tierney's opinion that to the extent that risk is implicated, revenue decoupling would reduce risks for both the Company and its ratepayers as opposed to shifting it from to the utility to customers.

HEARING

Over the course of the months of November and December, the Commission conducted duly noticed evidentiary hearings to further investigate the numerous issues raised in this Docket. The following appearances were entered:

FOR NGRID:	Thomas R. Teehan, Esq. Robert Keegan, Esq., Keegan & Werlin Cheryl M. Kimball, Esq., Keegan & Werlin
FOR THE DIVISION:	Leo Wold, Esq. Assistant Attorney General
FOR THE ATTORNEY GENERAL:	Ladawn S. Toon, Esq. Special Assistant Attorney General
FOR THE NAVY:	Audrey Van Dyke, Esq.
FOR TEC-RI:	Michael R. McElroy, Esq. Schacht & McElroy
FOR ENE:	Jeremy McDiarmid, Esq.
FOR EERMC:	R. Daniel Prentiss, Esq. Prentiss Law Firm
FOR THE WILEY CENTER:	Jean Rosiello, Esq. MacFadyen, Gescheidt & O'Brien
FOR CLF:	Jerry Elmer, Esq.
FOR THE COMMISSION:	Patricia S. Lucarelli, Esq. Chief of Legal Services

At the hearing, the parties were given the opportunity to cross-examine the witnesses presented. The considerable testimony is contained in the transcripts. Because of the Company's failure to completely respond to outstanding data requests until February 9, 2010, the record did not close until that date.

DECISION

On February 9, 2010, the Commission held an open meeting to decide the matter. The Commission was faced with a number of extremely difficult decisions on the issues presented in this case. In deciding on the issues and the utility's request for additional revenues, the Commission is required to balance the interests of the utility and its ratepayers to ensure that the rates allowed are just and reasonable. *Narragansett Electric v. Harsh*, 117 R.I. 395, 368 A.2d 1194 (1977) *citing FPC v. Hope Natural Gas Co.,* 320 U.S. 591, 602-3, 64 S.Ct. 281, 287-288, 88 L.Ed. 333, 344-345 (1944). In balancing those interests, the Commission reviewed hundreds of documents, pages of testimony, data responses and transcripts and listened to multiple days of oral testimony. The deliberative process of the three Commissioners was exhaustive and comprehensive. The outcome reflects the decision of the majority of the Commissioners. References to the Commission throughout the Decision Section shall mean the majority. All issues to which Chairman Germani concurred may be found in the February 9, 2010 transcript of the Open Meeting and the issues to which he dissented will be found in a dissenting opinion that will be filed subsequent to his review of this document.

I. RATE OF RETURN

A. Return on Equity

The Rhode Island Supreme Court has stated that "the proper rate of return 'is a matter of judgment, not an immutable number.'" *Blackstone Valley Electric Company*, Docket No. 1605, Order No. 10695 (issued May 12, 1982) *citing Providence Gas v. Burman*, 376 A.2d 687 (R.I. 1977). A public utility is not entitled to earn a return that may be earned by a highly profitable enterprise; however, the return should be sufficient to permit the utility to maintain financial integrity, attract necessary capital and fairly compensate investors for the risks they have assumed while at the same time providing appropriate protection to the relevant public interests, both existing and foreseeable. *Bristol County Water Company*, Docket No. 1502, Order No. 10355 (issued January 15, 1981)(citation omitted). The Company's original filing proposed a return on equity of 11.6%. The Division filed testimony supporting a return on equity of 10.1%. Both parties presented extensive testimony in support of their positions and challenged the positions of each other. Even though Mr. Moul acknowledged that he was aware that the Commission has expressed a preference for the DCF[5], the Company's 11.6% proposal was based on a review and averaging of the calculations of the DCF, CAPM and the Risk Premium methodologies for a proxy group of seven electric and combined electric and gas utilities. The Division's recommendation of 10.1% was based on an evaluation of two proxy groups, one consisting of electric utilities and one consisting of gas utilities using the DCF method and then confirming the results by evaluating a calculation of the CAPM.

While recognizing the difficulty in finding a group of companies that are exactly alike or very closely similar to NEC, the Commission found both the Company's and the Division's proxy groups to be different from NEC. The most glaring discrepancy was that the Company's proxy group was composed of only utilities that had some form of revenue decoupling, something that NEC does not have. Both parties, the Company and the Division, were highly critical of the other's choice of a proxy group. The Commission finds validity with both the Division's and the Company's criticisms of the

[5] Transcript of Hearing, November 12, 2009 Testimony of Paul R. Moul p.56.

other's group noting, however, that the Division provided a group more similar in nature to NEC.

Again, Mr. Moul's proxy group contained only companies that have some form of revenue decoupling. During the hearing, when asked why he only chose companies that had revenue decoupling as being comparable to NEC, he responded that the risk implications associated with decoupling need to be addressed by the Commission in setting the ROE.[6] He stated that whatever the risk implications associated with decoupling, those would already be reflected in the analysis of the ROE.[7] When questioned further about his group having nothing in common with NEC if the Commission chooses not to accept the revenue decoupling proposal, Mr. Moul merely stated that he responded in a data response that the cost of equity should increase by 30 basis points if the Commission denies the revenue decoupling proposal.[8] Mr. Moul did not provide another group with characteristics similar to NEC to support this recommended increase of 30 basis points and when pressed, responded that NGrid was confident in obtaining Commission approval of its revenue decoupling proposal.[9] Why he chose 30 basis points when he identified a range of 10 to 30 was unclear to the Commission.[10]

In addition to choosing companies with revenue decoupling, Mr. Moul included companies with nuclear generation. He stated that he did not eliminate these companies because to do so would make his proxy group small which made him nervous. He further

[6] *Id.* at p. 31.
[7] *Id.* at pp. 31-32.
[8] *Id.* at p. 32.
[9] This confidence was also reflected in the direct pre-filed testimony of Timothy Stout whose stated in that testimony that NGrid proposed its three year Energy Efficiency Plan anticipating the approval of revenue decoupling.
[10] *Id.* at 70-71.

supported the inclusion on the basis that nuclear generation is regulated.[11] Mr. Moul stopped short of accepting Mr. Kahal's group when questioned about whether this group would be more appropriate should the Commission decide not to approve the decoupling proposal.[12] Disappointingly, even after this questioning, Mr. Moul never provided the Commission with satisfactory evidence to support using his proxy group or with another group that would support his assertion that absent decoupling, the 11.6% ROE would be too low.

In addition, Mr. Moul failed to update any of the figures used in his calculations which were done in the spring of 2009 even in light of the changes in the financial markets. He acknowledged that updating these figures would have resulted in his return on equity decreasing.[13] Mr. Moul testified that he was unaware of a utility's bond rating being upgraded solely because it implemented revenue decoupling. He admitted that NGrid plc's A- bond rating was a positive indication relative to the financial state of the Company.[14] Further evidence of how Mr. Moul's figures were not representative of the current financial markets can be found in his recommendation for a cost of long-term debt which he recommended be set at 6.79% and which the Company ultimately issued for a combined weighted average 5.29%.[15]

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[11] Transcript of Hearing, November 12, 2009, Testimony of Paul R. Moul pp. 44-45.
[12] *Id.* at p. 34.
[13] *Id.* at pp. 40-42.
[14] *Id.* at p. 76.
[15] On April 16, 2010, NGrid filed a letter with the Commission regarding its long-term debt rate. In that letter, NGrid noted that on March 22, 2010, the Company concluded its $550 million long-term debt issuance and calculated the combined weighted average effective debt rate from the $550 million debt issuance to be 5.298%. Additionally, per the Company's original request, NGrid proposed to issue $512 million of long-term debt with a projected nominal interest rate of 6.70% (effective rate 6.79%). The annual debt service of this issuance was projected to be $34.7 million (Schedule NG-PRM-1, p. 1). The Commission ruled that the appropriate long term interest rate should reflect the actual cost of the debt issuance. Ultimately, the company issued $550 million of new long term debt with a weighted average effective rate of 5.3% equating to an annual debt service cost of $29.4 million. Thus, even though the

Even though Mr. Moul acknowledged that the Commission has historically expressed a preference for the DCF method for setting an authorized rate of return, he chose to propose a rate based on an average of the DCF, the RP and the CAPM. This is in contravention of the Commission's long standing policy. *See e.g., In re Valley Gas Co. & Bristol & Warren Gas Co.,* Docket No. 2276, Order No. 14834 (where the Commission stated its preference for the DCF methodology). Mr. Moul's failure to provide current figures and calculations to the Commission and similarly situated companies to comprise an acceptable proxy group, coupled with his unnatural confidence and anticipation of the approval of the revenue decoupling proposal, extinguished his credibility in the eyes of the majority of the Commissioners. The Commission finds NGrid witness, Paul R. Moul, not credible in his presentation of information especially regarding capital structure and return on equity, because he failed to provide the Commission with an appropriate and acceptable proxy group of companies that were similar to Narragansett Electric and used only companies that had some form of revenue decoupling and because he failed to provide the Commission with updated data reflecting the current financial climate upon which to make its decision. Because of this finding that Mr. Moul did not provide credible information to the Commission, the majority gives no weight to his testimony.

The Commission believes that using Mr. Kahal's proxy groups to calculate an appropriate ROE is more realistic and representative of an adequate return for NGrid as the companies comprising this group are more similar to NEC. The Commission, however, does not believe that Mr. Kahal's recommendation of a 10.1% ROE was

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Company issued more debt than originally proposed, the annual cost of debt service decreased by more than $5.3 million.

reasonable in light of the Division's response to the Commission's First Data Request. When asked to recalculate the ROE using the methodology approved by the Commission in previous dockets, specifically Docket No. 2038, Order No. 14048, Docket No. 2276, Order No. 14834 and Docket No. 2286, Order No. 14859, Mr. Kahal's average of the midpoints for his electric and gas proxy groups using a six-month average ending August 30, 2009 and a six-month average yield and "spot" dividend yield ending August 30, 2009, produced a ROE of 9.8%. Specifically, Mr. Kahal's calculations resulted in ROEs with midpoints of 9.5%, 9.6%, 10.0% and 10.1%. It is also worthy to note that the average of Mr. Kahal's electric proxy groups as reflected in the response to the Commission's data request produced a ROE of 9.55%, a result that arguably is justifiable on a stand-alone basis given the nature and comparability of the underlying electric operations.

These calculations are consistent with the methodology approved by the Commission in the Dockets set forth above. Additionally, the Commission acted well within its purview to request the recalculation in response to cross examination of testimony previously provided by Mr. Kahal and to rely on these results even though they differed from his recommendation. *Valley Gas v. Burke*, 446 A.2d 1024 (R.I. 1982). Furthermore, these ROE outcomes are not out of the range of other National Grid USA Utility Subsidiaries as provided by the Company. Specifically, Keyspan Energy Delivery-New York and KeySpan Energy Delivery – Long Island have an authorized ROE of 9.8% set in January 2008, Energy North Natural Gas has an authorized ROE of 9.54% set in August 2008, Granite State Electric has an authorized ROE of 9.67% set in July 2007 and National Grid Generation LLC has an authorized ROE of 9.50% set in

January 2004. The Commission finds the average of 9.8% which reflects the average results produced by both the gas and electric proxy groups, to be fair and reasonable, and fully supported by the evidence, and such that return should be more than adequate for the Company to attract necessary capital.

B. Capital Structure

NGrid proposed a capital structure of 50% common equity with an actual cost rate of 11.6%, 44.80% long-term debt with an actual cost rate of 6.79%, 5.00% short-term debt with an actual cost rate of 2.50% and 0.19% preferred stock with an actual cost rate of 4.50%. By the end of the hearing and in light of the approval by the Division of Company's application for authority to issue long term debt in Docket No. D-09-49, the Company's request was for 50.05% common equity at 11.6%, 44.78% long term debt at the actual cost rate after the issuance, 4.98% short term debt at 2.50% and 0.19% preferred stock at 4.50%. The Division proposed 47.50% common equity at 10.1%, 47.33% long term debt at 6.1% which was modified when Mr. Kahal updated his figures to 5.60% or the actual cost after debt issuance, 4.98% short term debt at a cost rate of 1.60% and 0.19% preferred stock at a 4.50% cost rate. It is obvious that the disagreement between the Division and the Company lies with the amount of equity and long term debt.

The Commission will utilize the capital structure of a utility in setting rates unless that capital structure is not reasonable for rate setting purposes. In the instant case, the capital structure of NEC is over-reliant on equity with 85.57% being equity and 14.4% being debt. The overreliance on equity deviates from sound utility and rate setting practices.

When the Commission is faced with an inappropriate capital structure from which to set rates, it may either rely on the capital structure of the parent, in this case NGrid plc, or a proxy group. *In Re: New England Gas Company's Distribution Adjustment Clause*, Docket No. 3459, Order No. 17524 (issued August 1, 2003); *Public Service Commission of State of New York v. FERC*, 813 F.2d 448 (1987). Both Mr. Moul and Mr. Kahal resorted to the use of proxy groups to establish their recommendations, presumably in response to the Commission's decision in Docket 3943 to rely on the Company's proposed capital structure in that case, thereby reflecting an average of the equity percentages among the companies contained in NGrid's proxy group.[16] The primary basis for the Commission's decision in Docket 3943 was its rejection of the Division's position, which sought to impute NGrid plc's capital structure to its subsidiary utility in Rhode Island – again, the Narragansett Electric Company. However, due to the inability of the Division to present evidence in Docket 3943 concerning the appropriate adjustments that "should have been made to recognize the different treatment of regulatory assets in the UK,"[17] the Commission rejected the Division's recommendation to utilize NGrid plc's capital structure for ratemaking purposes.

Turning to the present case, the fact that the Commission has used a hypothetical capital structure or accepted the Company's recommendation in the past is irrelevant and not binding in the instant matter. *Michaelson*, supra. Furthermore, the Commission's finding in Docket 3943 was not at all intended to signal a retreat from the longstanding policy of utilizing the actual capital structure at the holding company level when the

[16] Mr. Moul was the Company's rate of return witness in Docket 3943.
[17] Docket 3943, Order No. 19563 (issued January 29, 2009) at 16.

subsidiary utility's capital structure is either non-existent[18] or otherwise deemed not reasonable for rate setting purposes. In fact, one of the more recent determinations concerning this very issue led the Commission to impute the holding company capital structure when interpreting a settlement agreement pertaining to the parent's subsidiary operations in Rhode Island. *In Re: New England Gas Company's Distribution Adjustment Clause*, Docket No. 3459, Order No. 17524 (issued August 1, 2003) at p. 100.

While there are other considerations that must be taken into account, such as the comparability of business risks as between the parent and subsidiary operations, as discussed later in the body of this order, the general ratemaking practice of relying on a parent capital structure does not, contrary to suggestions of NGrid, represent a departure from normal utility ratemaking practices historically used in this jurisdiction, other states, or even the Federal Energy Regulatory Commission ("FERC"). In fact, a FERC policy established in *Re Arkansas Louisiana Gas Co.* (1985) 31 FERC ¶ 61,318, 67 PUR4th 387, Opinion No. 235 (*Arkla*) is to use an actual capital structure rather than a hypothetical capital structure. The State of Missouri also followed this practice and was affirmed in *State of Missouri Office of the Public Counsel v. Public Service Commission of the State*, after the Court found it appropriate to use Southern Union's capital structure for Missouri Gas Energy ("MGE"), an operating division of Southern Union that did not have its own discernable capital structure. As the Court noted, "MGE *is* Southern Union; it is bound by the decisions of Southern Union's management, and potential investors desiring to invest in MGE must do so by investing in Southern Union." *State of Missouri*

[18] This was, in fact, the actual case with Docket 3459, where Southern Union's Rhode Island gas operations (d/b/a New England Gas Company) were not contained in a distinct corporate entity, but rather operated as a "division" of Southern Union's national operations with shared balance sheets.

Office of the Public Counsel v. Public Service Commission of the State, 293 S.W.3d 63, 83 (Mo.App. 2009). Based on the evidence concerning corporate governance in the instant proceeding, these principles are highly relevant to the capital structure determinations the Commission must make in this case. Any investor that seeks to invest in NEC, must do so by acquiring stock in NGrid plc.[19]

As occurred during the proceeding in Docket 3943, the same question about the propriety of using NGrid plc's capital structure arose in the instant case, except that the issue surfaced *after* the parties filed their respective recommendations in the form of prefiled testimony. Significantly, as reflected in Commission Record Request 44[20] and in the subsequent response by the Company as reproduced in its entirety below, the propriety of using NGrid plc's capital structure for ratemaking purposes was indeed a live issue in the case:

> <u>*Request:*</u>
>
> *What is the capital structure of National Grid plc, with all adjustments made to account for cash assets, RAV, etc.? What percentage of the National Grid plc operations are unregulated?*
>
> <u>*Response:*</u>
>
> *National Grid plc's capital structure as of March 31, 2009,* ***<u>determined in accordance with US GAAP and adjusted for cash assets and RAV</u>*** *is comprised of approximately 38 percent equity and 62 percent debt. Only five percent of National Grid plc's operations are regulated. (emphasis supplied).*[21]

What is surprising to the Commission is that the introduction of this significant piece of evidence, which was the critical "missing link" in Docket 3943, should go

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[19] Transcript of Hearing. November 12, 2009, Testimony of Julie M. Cannell at p. 220.
[20] The additional information on NGrid plc's capital structure was requested in Commission Data Request 15-5.
[21] Response was prepared by or under the direction of Andrew E. Dinkel III and dated November 12, 2009.

unnoticed or ignored by the parties through the remainder of the case. This Commission is statutorily bound to ensure that rates are just and reasonable, and that any approved rate increases are otherwise necessary for the utility to obtain reasonable compensation for services rendered to the public. R.I. Gen. Laws §§ 39-3-11 and 39-3-12. The importance of establishing the right level of common equity for ratemaking purposes was highlighted during the testimony. Given the significant disparity in the cost of debt versus the cost of common equity, and compounded with the impact of collecting from ratepayers the federal income taxes associated with every dollar of equity, the real cost rate of common equity to ratepayers is closer to 20 percent.[22] This rate is markedly greater than the 5.3% debt rate that NEC just obtained for its recent long term debt issuance.[23] In this context, arriving at the appropriate capital structure is one of the most critical issues that the Commission must decide in setting rates. If the common equity is set too high, substantial ratepayer dollars will flow to the parent that are beyond the level necessary to maintain credit worthiness of the Company.[24]

Contrary to the Commission's statutory and public interest obligations, NGrid argues that the Commission must ignore the evidence contained in Record Response 44 because none of the parties had incorporated such evidence into their respective positions. Such argument is squarely contradicted by the plenary authority conferred on the Commission by virtue of Title 39 of the Rhode Island General Laws, but moreover, is antithetical to the public interest which this Commission is duty bound to protect. Furthermore, such an argument ignores the Rhode Island Supreme Court's holdings that

[22] Transcript of Hearing, November 12, 2009, Testimony of Paul R. Moul,. at p. 15.
[23] See April 16, 2010 correspondence of Thomas R. Teehan,Esq. informing the Commission that the Company had successfully concluded its planned $550 million debt issuance and was able to obtain a weighted average interest rate of 5.298 percent, which was lower than what the Company and Division had stipulated to during the rate case (5.6 percent).
[24] Transcript of Hearing, November 12, 2009, Testimony of Paul R. Moul, at p. 16.

the Commission is not bound to rely solely on the recommendations of the witnesses in the case. *Wakefield Water v. Public Utilities Commission*, 457 A.2d 251 (R.I. 1983). In *Wakefield Water*, the Court stated that "the company contend[ed] that there was no evidence to support the method used by the commission as none of the experts recommended its use. Although we agree with both the company's statement of the law and its account of the testimony presented in the instant case today. The commission can devise a method of calculation not recommended by the experts provided that the evidence of record affords the commission some basis upon which they can in fact reach their conclusion." *Wakefield Water*, 457 A.2d at 253. As cogently articulated by the United States Court of Appeals for the Second Circuit, although in reference to the Federal Power Commission,[25] the Commission's execution of its duties "does not permit it to act as an umpire blandly calling balls and strikes for adversaries appearing before it; ***the right of the public must receive active and affirmative protection at the hands of the Commission***." *Scenic Hudson Preservation Conference v. FPC*, 354 F.2d 608, 620 (2nd Cir. 1965) (emphasis supplied). In the instant proceeding, the interests of the ratepaying public at large sanction the Commission's departure from the static positions of the parties in this case in order that important evidence be analyzed and incorporated into the findings of the Commission, if deemed necessary and appropriate by the Commission. For the reasons that follow, the Commission deems it to be necessary to once again depart from the stated positions of the Division and the Company in order to protect the public against unreasonable and unjust rates.

[25] The Federal Power Commission was the predecessor to the Federal Energy Regulatory Commission, which today regulates interstate transactions in the natural gas and electric industries.

Having established that NGrid plc's "capital structure as of March 31, 2009, determined in accordance with US GAAP, and adjusted for cash assets and RAV is comprised of approximately 38% common equity and 62% debt…[with] [o]nly five percent of…operations …unregulated,"[26] the next step must be to examine the comparability of NGrid plc's operations to those of its Rhode Island subsidiary, namely NEC. The relative business risks of the two entities, determined primarily by the nature of the underlying operations, must be reasonably similar. *Public Service Commission of the State of New York v. Federal Energy Regulatory Commission*, 813 F.2d 448, 460 (D.C. Cir. 1987). While NGrid plc contains approximately 95 percent regulated operations, NEC is 100% regulated. Thus, the Commission finds that there is a high degree of comparability between the parent and NEC's utility operations in Rhode Island. The risk profile of NGrid plc and NEC are also comparable, as reflected in the current bond ratings of the two entities.[27]

Based on the evidence, the Commission can reach a number of findings. First, the capital being supplied in the form of common equity to support NEC's regulated operations in Rhode Island is supported by the common equity issued by the parent, NGrid plc. The risk profile of NEC, given its 100 percent regulated operations, is slightly lower than the risk profile of NGrid plc, as reflected by the current bond ratings of the two entities. If the Commission adopts either the Company's or the Division's recommendation for setting the level of common equity, it would likely result in excess ratepayer dollars flowing to NEC, and ultimately to NGrid plc. James C. Bonbright, *Principles of Public Utility Rates* 309 (2nd ed. 1988). Based upon the foregoing findings

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[26] Response to Commission Record Request 44.
[27] Exhibit NGrid-63, attachment to Div-31-11. In fact, NGrid plc's bond rating is slightly lower than NEC but still very favorable in the view of bond rating agencies.

and evidence in the record, the Commission concludes that it is appropriate to impute the capital structure of NGrid plc to NEC for ratemaking purposes.

On a separate but related item, it is worth noting that Mr. Kahal's recommended capital structure was considerably higher in terms of overall costs to ratepayers than the available alternative of the parent company. His recommendation was obviously driven by his selection of the companies contained in his proxy group. That those companies all contain higher equity percentages than NGrid plc is not surprising since many of those companies contain substantially higher percentages of unregulated operations, thus necessitating higher equity percentages for purposes of maintaining credit worthiness. The record demonstrates that many diversified holding companies in the United States, which are predominant in the proxy groups of witnesses in this case, have higher degrees of risk whether due to unregulated power assets,[28] regulated generation,[29] ownership in nuclear generation,[30] unregulated gas marketing,[31] energy management and gas storage,[32] pipeline construction, and containerized shipping.[33] In the simplest of terms, unregulated operations are viewed by investors and investor analysts generally as more risky than stand alone monopoly utility operations, such as NEC.[34] Thus, it bears repeating that use of Mr. Kahal's recommended capital structure, would provide incremental – but unjustified – revenues to the Company given the overall degree of unregulated operations in the companies comprising his proxy group. For the same reason, and as admitted by Mr. Kahal, the Division's 10.1 percent ROE estimate may be

[28] Transcript of Hearing, November 12, 2009, Testimony of Paul R. Moul, 11/12/09, at p. 23.
[29] *Id.* at p. 22.
[30] *Id.* at p. 23.
[31] Division Response to Commission Data Request 4-2.
[32] *Id.*
[33] *Id.*
[34] Statement of Division witness Kahal, see Division Response to Commission Data Request 4-2.

deemed by the Commission to be a "conservatively high recommendation,"[35] and constitutes further support for the slightly lower 9.8 percent ROE determination reached by the Commission.

Strictly applying all of the principles and findings discussed above would arguably provide the Commission with latitude to utilize NGrid plc's capital structure, which contains 38 percent common equity.[36] However, in light of Mr. Kahal's overall credibility in this case, the Commission will still afford some weight to his capital structure recommendation, and will select the midpoint between NGrid plc's common equity percentage (38 percent) and Mr. Kahal's recommendation of 47.5 percent. That midpoint computes to 42.75 percent and will ensure that the Company can execute its long term debt issuance as well as maintain its current, favorable bond ratings.[37] The Commission finds this result to be appropriate based on the evidence in the record, and further, that it strikes a reasonable balance between the interests of ratepayers and shareholders. *Pioneer Natural Resources USA, Inc. v. Public Utility Commission of Texas*, 2009 WL 5149916 (Tex.App.Austin)(where the court held that the commission was not required to select the position of a party but was permitted to balance competing interests that were supported by evidence in the record). Accordingly, the Commission authorizes the Company to collect sufficient revenues in rates to support and maintain a

[35] Division Response to Commission Data Request 4-2.

[36] To be fair, one could argue that something lower than 38 percent would be appropriate for NEC, since NGrid plc's unregulated operations indisputably drive up the composite risk of the parent, and in parallel fashion, drag down the parent's bond rating. In other words, but for the existence of unregulated operations at the NGrid plc level, the parent's common equity percentage might be lower, and in turn could translate into a lower percentage of equity for the subsidiary operations of NEC.

[37] Subsequent to the Commission's decision, the Company's compliance filing criticized many aspects of the Commission's decision in this case and in one instance warned that the rate decision would delay the issuance of a long term debt instrument. As stated above, the Commission was informed by letter dated April 16, 2010, that the debt issuance was concluded on March 22, 2010.

capital structure of 42.75% equity, 52.08% long term debt, 4.98% short term debt and 0.19% preferred stock.[38]

Regarding the costs of debt, the Commission finds the Division's recommendations to be reflective of the most updated and accurate information and accepts these recommendations for determining the cost of long term debt consistent with the approach agreed upon by NGrid and the Division. Finally, the Commission finds the Division's recommendations for the cost of preferred stock and short term debt to be the most updated and accurate and therefore, accepts these recommendations for determining the costs of short term debt at 1.60% and preferred stock at 4.50%.

II. REVENUE REQUIREMENTS

A. Operating and Maintenance Expense

1. Incentive Compensation

NGrid proposed increasing the test year by approximately $2.4 million for incentive compensation for NEC and service company employees. The Division recommended reducing this amount by half, arguing that at least half was based on the Company's attainment of financial goals and, therefore, not appropriate to be recovered from ratepayers. In evaluating whether the $2.4 million adjustment was just and reasonable, the Commission considered whether the costs would provide a benefit to the

[38] The Commission is cognizant that as a general ratemaking principle, the common equity ratio does bear some relation with the appropriate cost of equity. When asked specifically whether the use of the NGrid plc's capital structure would affect his recommendation, Mr. Kahal responded that it would not significantly affect his conclusions. Division's Response to Commission's Third Set of Data Requests 3-2. In acknowledging that there is some impact by virtue of the Commission's downward adjustment of the Company's percentage of common equity, the Commission's actions neutralize any such concern by 1) selecting of the midpoint between NGrid plc's actual percentage of common equity and Mr. Kahal's recommended 47.5%; and 2) taking into account Mr. Kahal's conservatively high recommendation due to the greater influence of unregulated operations for the Companies contained in his proxy group. See Response to Commission Data Request 3-2. The Commission believes in light of the foregoing, the ultimate result is not only appropriate but safely falls within the zone of reasonableness.

ratepayers. The nexus that must be established is that the attainment of financial goals is for the benefit of ratepayers. *See e.g.*, *Commonwealth Edison Company v. Illinois Commerce Commission*, et al., 2009 WL 3048420 Ill.App. 2 Dist. (where the Court disallowed fifty percent of the incentive pay plan finding it only provided a tangential benefit to ratepayers). Where the costs are tied exclusively to shareholder return and do not provide a benefit to ratepayers, they are unreasonable. *US Communication , Inc. v. Public Service Comm'n of Utah*, 901 P.2d 270, 276 (Utah 1995), *See also Entergy Arkansas Inc. v. Arkansas Public Service Comm'n*, 289 S.W.3d 513, 525 (Ark. Ct. Ap. 2008).

Mr. Effron testified that the attainment of financial goals is a shareholder oriented goal and that the shareholders are the primary beneficiaries of increases to earnings and as such should bear the costs of the incentive compensation related to earnings.[39] He also testified at the evidentiary hearing that to the extent that the attainment of financial goals benefit shareholders, they are not proper for inclusion in the revenue requirement. To the extent that what is being incentivized is a goal to improve earnings, it is not a benefit to ratepayers.[40] Mr. Dowd, NGrid's witness, disputed Mr. Effron's recommendation and testified that NGrid's financial measures are used for the determination of payouts and are related to the financial performance of NGrid plc not NEC.[41] He described how some employees get paid for their job in two pieces, one piece of which is dependent on whether NGrid meets its financial goals.[42] Mr. Dowd stated that 40-50% of the incentive

[39] Exhibit Div-1 at 6.
[40] Transcript of Hearing, November 5, 2009, Testimony of David J. Effron at pp.200-201.
[41] *Id.*, Testimony of William F. Dowd at p.90.
[42] *Id.* at 129-130.

pay is linked to individual objectives like service quality measures, but the remaining portion is directly related to the Company's financial performance.[43]

The Commission has previously held that ratepayers are responsible for that portion of executive compensation that directly benefits them and that shareholders are responsible for that portion that benefits them. *Providence Gas*, Docket No. 2286, Order No. 14859. The Rhode Island Supreme Court also upheld a Commission decision disallowing a Supplemental Executive Retirement Plan and finding that the Company's attempt to reward executive talent for employment not dedicated to ratepayers does not benefit ratepayers. *Providence Gas v. Malachowski*, 656 A.2d 949, 952 (R.I. 1995).

In this case, the Commission is not persuaded that the $2.4 million cost associated with incentive compensation is wholly for the benefit of ratepayers. The Commission believes Mr. Effron's testimony that benefits tied directly to the Company's financial performance are not benefits directly benefiting ratepayers and finds the Division's position to be meritorious. Additionally, the Commission cannot justify increasing rates in order that NGrid attain higher profits and higher stock prices or shareholder value. The Commission finds Mr. Dowd's testimony unpersuasive in establishing any link between the Company's attainment of financial goals and ratepayer benefits. Because the Company was unable to satisfy the Commission that the 50% of the $2.4 million that was directly tied to the Company's attainment of its financial goals will benefit ratepayers, $1.2 million of the Company's proposed adjustment to incentive compensation will be denied. If the Company believes that this compensation is necessary, such amount should be borne by shareholders who are the primary beneficiaries of NGrid's attainment of its financial goals. By voting against one half of the proposed adjustment to incentive

[43] Exhibit NGrid-7 at pp.8-9.

compensation, the Commission is not assuring disfavorable action toward incentive compensation. The Commission is simply not passing the cost through in rates. Nothing, herein, would prohibit the Company from using shareholder funds to provide incentive compensation to employees whose performance leads to the attainment of such financial goals which benefit shareholders. The law requires that the rates be just and reasonable and the Commission finds that the portion of the rate that is tied to the Company's attainment of financial goals is not just and reasonable. While the record in Docket No. 3943 may have supported the majority's decision to allow for incentive compensation, the evidence presented to this Commission in this docket is not satisfactory to allow for ratepayers to fund that portion of incentive compensation that was not proven to directly benefit ratepayers. Furthermore, the Supreme Court has held that "[e]ven assuming that the commission has in fact altered its position on [an] issue…[it] is not bound by either a factual determination reached or a method utilized in an earlier docket." *Michaelson v. New England Tel. & Tel.*, 404 A.2d 799 (R.I. 1979)

2. Union Labor Contract

NGrid proposed a pro forma change of $1,362,802 to include wage costs through the rate year for new hires required under its union contract. The Division recommended eliminating this adjustment from the cost of service. Mr. Dowd testified that in negotiating the labor contract, the union sought to increase its number of employees in three rosters and to limit the use of outside contractors. Mr. Dowd also testified that in reaching an agreement, the Company agreed to an increase in employees over a four year period but only agreed to the elimination of platform contractors, which he described as a small subset of contractors used by NGrid.[44] He stated that with regard to the ramp-up of construction and capital replacement and the inspection and maintenance and vegetation management programs, the contract would allow NGrid to satisfy the employee requirements necessary for those initiatives. Mr. Dowd admitted that without the ramp-up, NGrid would not need the contractors to work the same amount of time because they had additional employees to perform the work that the contractors had been doing.[45] The Division objected to the requested increase stating that this expense should be offset by the reduction in outside contractors and that the contract language specifically ties the increase in union staffing to the reductions in the use of outside contractors.[46]

The Commission finds that NGrid did not provide sufficient information to support this pro forma change. Beyond stating that the contract language required the addition of new employees, NGrid did not present sufficient evidence that this additional cost to ratepayers was just and reasonable or necessary to maintaining the distribution system. As will be further discussed, the Commission also finds that based on its admitted top quartile reliability performance, NGrid also did not persuade the Commission that the substantial ramp up activity in inspection and maintenance and vegetation management noted by Mr. Dowd was necessary to maintaining the Company's reliability in the distribution system.

NGrid had the burden of providing extensive detail regarding the expenses associated with these additional employees. *Providence Gas*, Docket No. 2286, Order No. 14959, *see In Re Narragansett Bay Comm.'n Abbreviated Application for Rate Relief*, Docket No. 3592, Order No. 18124 (issued January 21, 2005)(where the

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[44] Transcript of Hearing, November 5, 2009, Testimony of William F. Dowd at pp. 94-100.
[45] *Id.* at p.108-110.
[46] *Id.*,Testimony of David J. Effron at pp.205-206.

Commission limited funding of labor expense when the utility failed to provide sufficient evidence that it was proactive in limiting personnel expense). In the instant case, NGrid provided no evidence that the work to be performed by these additional employees could not be assumed by existing employees. The Commission finds Mr. Effron's testimony meritorious. Specifically, the Company's own admission indicates that it will cease to use platform contractors.[47] It is evident that the platform contractor expense will cease and therefore, Mr. Effron is correct in asserting that at least some of the cost of the additional employees should be offset by the elimination of the expense for platform contractors. Additionally, Mr. Effron also aptly noted that the language in the collective bargaining agreement allows the Company the right to assign the work between employees and contractors enabling the company to control the $10 million outside contractor expense.[48] This is further evidence that the Company can offset the expense of the new hires by reducing the cost of outside contractors through good management decisions.

Even though it argues to the contrary, Mr. Dowd's testimony that contract negotiations concluded with a commitment to increase the number of employees in lieu of using contractors to do the work and that the Company's intent was to "revert to a model where there are more employees and fewer contractors" clearly supports the Commission's findings.[49] In light of the specific contract language requiring the Company and the union to work together to jointly identify the percentage of work performed by employees and contractors and the requirement to cease using platform contractors as well as Mr. Dowd's testimony regarding the Company's intent during

[47] Transcript of Hearing, Testimony of William Dowd, November 5, 2009 at p.97.
[48] Exhibit Div-1 at p. 7.
[49] Transcript of Hearing, Testimony of William Dowd, November 5, 2009 at p. 92-93.

contract negotiations, the Commission finds Mr. Dowd's testimony more convincing and credible than Mr. Pettigrew's testimony that the Company expects to increase the number of contractors.[50]

Finally, the Company is well aware of the fact that even though it has contractually agreed to hire new employees, this does not relieve it of its burden to prove that the cost is just and reasonable. The union labor contract does not dictate what the Commission must approve to be collected in rates.

3. Storm Fund Contributions

Currently, ratepayers contribute $1.04 million annually to the Storm Fund. The purpose of the Storm Fund is to recover the costs associated with a catastrophic storm when those costs are greater than $728,000 for a single storm.[51] The Company's revenue requirement included the $1.04 million amount for the rate year. The Division recommended that the $1.04 million not be included in the revenue requirement because for the twenty-seven years the storm fund has been in existence, the total amount of the expenses has not reached the level to which the storm fund is funded at the current time, which is approximately $21.5 million.[52] When questioned about whether suspending the funding of the storm fund would be harmful to the Company, Mr. O'Brien suggested that if the Commission were to suspend funding of the storm fund, it establish a threshold balance where the $1 million would be reinstated should the fund drop below that level.[53] In its brief, the Company conceded to the Division's recommendation that the fund be suspended with a threshold established for reinstatement.

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[50] Transcript of Hearing, Testimony of John Pettigrew, November 3, 2009 at p. 155.
[51] Exhibit NGrid-23 at p.12.
[52] Exhibit Div-8 at pp. 4, Exhibit NGrid-59 Response 27-6.
[53] Transcript of Hearing, November 5, 2009, Testimony of Robert L. O'Brien at pp. 28-32.

The Commission finds no reason to continue funding of the storm fund in light of the fact that there is a substantial amount of money, in excess of $20 million, currently in the fund. The Commission finds it is reasonable to suspend this funding and to reinstate funding subject to Commission approval, if the storm fund balance falls below a threshold of $20 million.

4. Storm Damage Expense

NGrid proposed including the $4,410,401 test year amount of storm damage expense in the revenue requirement, and Mr. O'Brien noted that this amount was representative of the going-forward costs which ranged from $2.9 million to $4.1 million from 2005 through 2007.[54] Mr. Effron disagreed with Mr. O'Brien's use of the test year and recommended that the Commission use a five year average because during the five year period the expense had fluctuated significantly. He pointed out that based on his calculations, the test year amount should be reduced by $1,395,000 to reflect a five year average which includes the test year.[55] While the Company disagreed with Mr. Effron's adjustment, it did not provide any evidence that the proposed amount of expense was likely to occur in the future nor did it explain the drop in the expense in 2007 to $2,860,288. The Commission has used a five year historical average in the past to normalize expenses or revenues that fluctuate from year to year. *See Pawtucket Water,* Docket No. 3497, Order No. 17574. In light of the fact that costs have fluctuated considerably over the past five years, ranging from $437,428 in 2004 to $4,410,401 in

[54] Exhibit NGrid-23 at p.16.
[55] Transcript of Hearing, November 5, 2009, Testimony of David J. Effron at pp.223-227.

2008, dropping in 2007 to $2,860,288[56], the Commission agrees with Mr. Effron that a five year average is appropriate.

5. Injury & Damage Expense

NGrid proposed including the test year recorded amount of injury and damage expense of $7,055,000 in the revenue requirement. Mr. O'Brien testified at the hearing that it is reasonable to believe that the Company will experience events that result in litigation at an expense level comparable to the test year.[57] The Division recommended excluding $2.5 million from the amount arguing that this portion of the total expense represented an anomaly that was not likely to recur. The Commission concurs with the Division's position noting that NGrid presented no evidence that this amount was recurring. In fact, the adjustment is based on nothing more than Mr. O'Brien's conjecture that this type of litigation will occur in the future which was minimized by Mr. Pettigrew's response to a Commission Record Request assuring that subsequent to the accident causing this expense, NGrid initiated a public awareness program warning of the dangers of overhead power lines.[58] This program should reduce the chances of this type of accident occurring again in the future. The test year amount is significantly more than the four prior years and the Commission believes that eliminating the $2.5 million will bring this expense more in line with the previous year's expense.[59]

6. Rate Case Expense

NGrid requested that the Commission amortize the cost of the rate case over a two year period. In its post hearing brief, however, the Company amended its request to a

[56] Exhibit NGrid-55-23-1B
[57] Transcript of Hearing, November 5, 2009, Testimony of Robert L. O'Brien at pp.10-11. It should be noted that the Company's brief changed the $2.5 million to $2.25 million as set forth in RR-Comm-19.
[58] RR-Comm-19.
[59] Exhibit Div-8, Surrebuttal Testimony of David J. Effron at 8.

three year amortization period which is what the Commission allowed in Docket No. 3943. The Division recommended a five year amortization period pointing out that the amount of time between the last two filed rate cases and the instant case supports a five year period. The Commission believes that a five year amortization period is appropriate and is supported by the time interval between the two prior cases. Additionally, NGrid did not present any evidence it would file rate cases on a more frequent basis or that the five year period would be to the financial detriment of the Company or its ratepayers in terms of necessitating a shorter period within which to amortize rate case expense.

7. Outside Legal Fees

NGrid requested that the amount of outside legal expense for the test year of $1,756,370 be included in the revenue requirement. The Division recommended that this amount be reduced by the amount of the cost of certain Constellation litigation[60] as this litigation was complete and not likely to recur. Like the argument made for injury and damages expense, the Company argued that there will continue to be instances where the Company must obtain outside counsel to defend its interests.[61] The Commission notes that although the Division recommended an adjustment of $419,000, the evidence provided by NGrid shows the total expense over a three year period from 2006 through 2008 for the Constellation litigation to equal approximately $600,000.[62] A four year average of the outside legal expense absent the cost of the Constellation matter equals $1,162,575. The Commission is persuaded by the Division's argument that the litigation over the interpretation of legacy long term Wholesale Standard Offer contracts signed in

[60] The Constellation Energy Commodities Group, Inc. litigation arose out of a dispute between Constellation and NGrid over whether a fuel adjustment factor was required to be applied to the base amount of wholesale power for the period 2005 to 2009 among other issues.
[61] Transcript of Hearing, November 5, 2009, Testimony of Robert L. O'Brien at p.19.
[62] RR-Comm- 20.

1998 was unique and unlikely to recur in the future. There was no evidence presented by the Company that this expense is likely to occur again.

The Rhode Island Supreme Court has stated that it will allow the Commission broad discretion in making pro forma adjustments to test year data when it is supported by evidence in the record. *Narragansett Electric v. Harsh*, 117 R.I. 395, 368 A.2d 1194 (1977). Here, the historical expense for outside legal fees has varied widely over the four year period for which the Company provided data. From 2005 to 2006, the expense, absent the cost of the Constellation matter, dropped by approximately $200,000 and then almost doubled the following year in 2007 before declining a little in 2008. There is no evidence presented that this expense will continue to rise, other than Mr. O'Brien's general statement that the Company will continue to have the need to hire outside counsel. The Commission will not rely on speculation in setting rates. The Commission believes that the historical average better reflects the normal annual outside legal expense that the Company can expect to incur in the future and is a time period appropriate to normalize these expenses since they have fluctuated from year to year. *Narragansett Electric v. Harsh*, 117 R.I. 395, 368 A.2d 1194 (1977). If the Commission had the additional data, it would have used the average of five years; however, the record request only asked for the historical data going back to the year prior to the initiation of the Constellation litigation. Thus, NGrid is authorized to collect in rates a total of $1,162,575 for outside legal fees.

8. Vegetation Management

NGrid requested that the Commission approve a pro forma adjustment of $1,857,000 for its vegetation management program. The Division recommended denying the pro forma adjustment. For vegetation management expense, the Commission will allow the Company $5,081,368. This amount represents the five year average of the Company's actual expense for the years 2004 through 2008.[63] The Commission finds that the $9.1 million requested for the rate year represents a significant increase in this expense. The Company failed to establish that such an increase was necessary. Mr. Pettigrew testified that reliability metrics for both SAIDI and SAIFI place the Company in the top quartile of reliability performance statistics for electric companies in the northeast United States for the last three years.[64] In further support of the Commission's decision to use a five year average is the fact that for 2006, and within the three year period of top quartile reliability performance, the Company spent less than $5 million in the first year.[65] In fact, even after the approximate $1.5 million increase in 2006, while the Company was in the top quartile of reliability, it further increased spending by another $1.8 million. The increase of more than $3 million over a two year period was not demonstrated as a necessary expense. Furthermore, the more than $9 million the Company now seeks was not shown to be necessary to maintain the top quartile reliability touted by the Company since 2006.

The evidence also shows that more than two times as many pole-related interruptions were caused by vehicles than by the weather or trees falling on the power lines.[66] Particularly troublesome to the Commission was Mr. Pettigrew's testimony about use of Rhode Island contractors to complete vegetation management. He asserted that NGrid would have the benefit of having contractors for vegetation that are located within

[63] Comm-11-2, Exhibit NG-2, Schedule NG-JP-2 p.1, Exhibit Div-1 Schedule DJE-4.
[64] Transcript of Hearing, November 3, 2009, Testimony of John Pettigrew at pp.31-32.
[65] Comm-7-9.
[66] Comm-7-11.

the state which would avoid transportation costs of getting the contractors to Rhode Island and would allow for the development of better relationships with the Rhode Island vendors. He identified the contractors as "several across New England and probably several within Rhode Island as well."[67] This testimony was contrary to the evidence provided by the Company in response to a data request asking the Company to identify the three tree vendors to whom a contract was awarded.[68] Not one of these vendors is a Rhode Island company or even a company from the Northeast. Not one of the three even has an office or permanent facility in Rhode Island. The Commission will not speculate about the reason for Mr. Pettigrew's representations but notes that when asked to support this one part of his testimony, the evidence provided contradicted it.

The Commission finds neither the Company's nor the Division's recommendation to be satisfactory. NGrid presented no evidence that absent its proposed conversion to four-year circuit based pruning, the Company will not be able to operate its electric distribution system as reliably as it has since 2006. Mr. Pettigrew did not present any evidence that the changes made to the vegetation management program and the costs associated with those changes produced the SAIDI and SAIFI performance ratings. In fact, his testimony was that these costs have increased since 2008.[69] There is substantial evidence in the record to support the Commission's use of a five year historical average, especially in light of the substantial increase in costs, even after the SAIDI and SAIFI performance ratings were in the top quartile. Furthermore, the Commission is not bound to approve on a position recommended by a party in a proceeding. *See Valley Gas Co. v. Burke*, 446 A.2d 446 (R.I. 1982) *citing Rhode Island Consumers' Council v. Smith*, 111

[67] Transcript of Hearing, November 3, 2009, Testimony of John Pettigrew at pp.80, 142,145-146
[68] Comm-12-1.
[69] Transcript of Hearing, Testimony of John Pettigrew, November 3, 2009 at p. 94.

R.I. 271, 302 A.2d 757 (1973)(where the Court found that the Commission was not bound to accept the entire testimony of an expert).

As the Commission has stated in the past and based on the evidence presented, the Commission does not believe that a forecasted test year is the most accurate method of determining just and reasonable rates. *Providence Gas*, Docket No. 1741, Order No. 11436 (issued November 28, 1984) at 8 (citation omitted). The Commission finds that the approach used by the Company, the forecasted test year approach, is speculative and unreliable. The Commission further finds that there is no way to verify the assumptions, estimates and judgments used by NGrid. The Commission has previously found use of the forecasted test year approach to be appropriate "when there is evidence of attrition and, even then, only as a check on a historical test year adjusted for known and measurable changes." In the instant case there was no such evidence. The forecasted test year approach has been described previously as "an accumulation of 'best guesses,'" *id.*, which this Commission does not believe can be used to establish a fair and reasonable rate for Rhode Island ratepayers on an expense that has increased so significantly and was not established to be necessary in maintaining the level of reliability achieved prior to its increase. *Id.* In the instant case, the Commission will exercise the discretion authorized by the Court and rely on the evidence in the record to support its decision to allow NGrid to collect the average of five years of vegetation management expense in the rate year.

9. Inspection & Maintenance

The Company requested recovery of approximately $4.7 million in inspection and maintenance expense as well as a reconciling mechanism to recover amounts in excess of that level. The $4.7 million included the test year expense plus a pro forma adjustment of approximately $2.1 million. The Division recommended denying the pro forma adjustment and the reconciling mechanism. Again and like with vegetation management, the Commission finds that it is appropriate to use a historical average to most accurately represent the costs that the Company should be expected to incur. The increase proposed for the rate year is significantly above the amount of increases for the prior years. Mr. Pettigrew provided testimony that the purpose of the inspection and maintenance strategy was to realize substantial gains in service reliability. However, he also provided testimony that SAIDI and SAIFI metrics indicate that the current system is and has been "top-performing" in terms of reliability even before the test year, which contradicts the Company's asserted need for such a substantial increase in spending.[70] There was no evidence presented of exactly what substantial gains would occur especially in light of the current exemplary reliability rating. The general statement that the system is aging is insufficient to convince the majority of Commissioners that the proposed expense is both reasonable and necessary to the service rendered. *See New England Tel. & Tel. Co.,* 446 A.2d 1376 (R.I. 1982); *Bristol & Warren Gas Co.*, 384 A.2d 298 (1978); *Providence Gas*, Docket No. 2286, Order 14859 at 30. The system will continue to age into perpetuity and begins aging as soon as its construction is complete.

The Commission agrees with Mr. Hahn that a targeted approach based on asset age is more reasonable and cost effective than the proposed plan articulated by the Company and that the substantial ramp up in this expense is not consistent with prior years.[71] This is further support for the Commission's apprehension with using a forecasted test year and of its decision above to rely on a historical test year

[70] Transcript of Hearing, Testimony of John Pettigrew, November 3, 2009 at pp. 31-32.
[71] Transcript of Hearing, Testimony of Richard Hahn, November 23, 2009 at pp.26-27, 36.

methodology. The current activities and operations have maintained a highly reliable system and the Company failed to convince the Commission that this further expense or the amount recently spent is necessary to maintain that reliability especially when it was achieved for so much less in prior years. It is important to note that the Commission's denial of NGrid's request for additional funds to ramp-up both inspection and maintenance and vegetation management will have no effect on the labor contract. Mr. Dowd testified that if the Commission does not approve the funding for the ramp up programs, it will have no effect on the terms of the collective bargaining agreement.[72]

Like its decision with vegetation management expense, the Commission finds that use of a historical average will better guarantee that rates are fair and reasonable. However, the data provided by the Company on February 9, 2010 upon which the Commission relied in making its decision, included only four years of historical data. Therefore, the Commission will deviate from the five year historical average it used for vegetation management and use a four year average. The Commission finds this to be fair in light of what it views as a considerable ramp up in this expense immediately preceding the Company's filing of its rate application. Furthermore, the Commission is compelled, based on the content of the letters filed by Mr. King and Deputy General Counsel Ronald Gerwatowski subsequent to its decision, to caution the Company that in light of the fact that a high level of reliability was achieved prior to the ramp up of the expenses in inspection and maintenance and vegetation management, the Commission expects reliability performance to be maintained. Since it was achieved at a lower cost, the Commission finds no basis in the record to conclude that the same high reliability performance cannot be maintained. Therefore, based on the above, the Commission will

[72] Transcript of Hearing, Testimony of William Dowd, November 5, 2009 at pp. 177-178.

allow the Company to collect the average of four years of inspection and maintenance expense in the rate year.

As for the reconciling mechanism, this Commission will not allow a utility to avoid the ratemaking process and the controls and safeguards established and guaranteed by traditional ratemaking process by implementing reconciling mechanisms as a general practice. While this is not a wholesale denial of reconciling mechanisms, the Commission believes that with the vast amount of data and expertise at the disposal of a company like NGrid, it is not unreasonable to expect that the Company can forecast its expenses and present those forecasts with a degree of certainty to the Commission. The Commission finds that these costs are not large, volatile and beyond the control of the Company. By denying NGrid's request, the Commission can ensure that ratepayers are protected and are not paying for services that are not fully investigated and ultimately confirmed as being appropriate, necessary, just and reasonable. Reconciling mechanisms diminish the Commission's ability to investigate the propriety of those costs. Furthermore, the Company did not present any evidence to establish that this expense was large, subject to fluctuations and beyond the control of the Company such that a reconciling measure was necessary to protect the financial integrity of the Company. The evidence presented was actually to the contrary. Based on the foregoing, the Commission denies NGrid's proposal for a reconciling mechanism for inspection and maintenance expense.

10. Transformation Expense

NGrid requested that $1.6 million be included in the revenue requirement. The Division recommended disallowing fifty percent of this amount incurred in the test year unless the Company demonstrated that the program produced net benefits for its customers, and further, that the program could not be performed at a lesser cost than other available measures. As the stated purpose of the this program is to improve customer satisfaction by boosting reliability to the top quartile and as the Company is already in the first quartile of performance for companies that participated in the benchmarking study for 2007, Mr. Pettigrew's statement that customers will benefit in the future[73] does not establish a direct benefit to ratepayers with any certainty to support rate recovery for this expense. Even though the Company argued that it should be allowed the entire expense because it satisfied the conditions established by Ms. Smith, Ms. Smith still testified against inclusion of this expense in the revenue requirement, and further indicated that the Commission would be justified in eliminating the entire expense.[74] The Commission is not persuaded that ratepayers will benefit in the future from continuation of this expense. The Commission finds the Division's evidence persuasive and while the Commission could eliminate the entire expense based on the evidence, finds that fifty percent of the expense should be denied.

11. Customer Contact Activities

The Company requested an additional $376,000 for the incremental cost associated with its increased level of calls that its higher level of collections activity generates. The Division objected to this increase, claiming that the cost should be offset by the decreased write-offs that should result from the increased calls. The Commission agrees with the Division that this added task should pay for itself and be balanced out by the increased amount of funds that the Company receives as a result of the additional

[73] Exhibit NGrid-17 at p. 23-24.
[74] Transcript of Hearing, Testimony of Lee Smith, November 23, 2009 at pp. 105-106.

collections efforts. Furthermore, the Company did not present any evidence that this is a cost necessary to maintaining the distribution system. The Commission finds that the requested funding is unnecessary and not a cost necessary for the operation of the electric distribution system.

12. Customer Advocacy Positions

The Company requested $182,000 in funding for two additional positions to assist eligible customers in identifying and enrolling in all programs available to them, including low income rates, arrears management programs, fuel funds, LIHEAP and fuel assistance. The Division objected to the funding of these two positions, noting that the duties of the positions are largely duplicative of Rhode Island service agencies. The Commission agrees with the Division that the duties of these two positions are duplicative of the efforts of various CAP agencies and the Office of Energy Resources. There are currently eight separate non-profit companies employing more than 1,000 people in the RI CAP agencies. At the present time, Rhode Island has sufficient individuals to perform the duties that the Company has described for these two positions. The Commission does not believe that it is necessary or reasonable to duplicate duties already being performed. While the Company may have established that these jobs have proven successful in other jurisdictions, it did not sufficiently rebut the Division's argument that the duties are already being performed by other agencies in Rhode Island or that these duties are necessary to maintaining the operation of the electric distribution system such that ratepayers should bear the additional costs. Accordingly, the Commission finds this cost is not just or reasonable and therefore denies the same.

13. Economic Development Program

NGrid requested an additional $1 million to be recovered through rates. The Division recommended that the Commission reject this proposal and deny recovery through rates. The Commission finds that the Company did not provide appropriate detail or any specifics including a cost/benefit analysis to support this program. NGrid's witness, Carmen Fields' testimony was vague and often non-committal when asked about the specifics of the proposal with regard to timing as well as terms, conditions and controls over the specifics of the proposed program. For instance, she was unable to identify whether or not there would be any terms or conditions on the grants awarded through the program, what would occur if a grantee was unable to fulfill the conditions of the grant, whether there were any vacant or underutilized structures in Rhode Island and even whether the Commission's denial of the proposal would result in a detrimental financial impact on the Company or Rhode Island ratepayers.[75] Additionally, NGrid did not identify a specific date on which the program would begin, acknowledging that very little of the proposed $1 million budget would be spent during the rate year. The Commission finds that based on the evidence, the proposed program is a duplication of some of the functions of the Rhode Island Economic Development Corporation and like the cost for customer contact activities, is not a cost that is just and reasonable or necessary to the maintenance of the electric distribution system.

14. Service Company Allocations

NGrid requested that the Commission include in the revenue requirement the amount recorded in the test year for service company allocations. The Division recommended disallowing $2.3 million associated with the GIS system survey. The

[75] Transcript of Hearing, November 13, 2009, Testimony of Carmen Fields at pp.131-132, 134, 136-137.

Commission finds that because the GIS survey is complete, there will be no costs associated with the survey in the rate year. The Company did not provide sufficient and specific information about the proposed pilot program intended to determine the extent of which it will engage in the enhancement of its underground GIS program.[76] Furthermore, the Company did not clearly define the cost of the project or a timetable for the program. While the proposed underground project is intended to cover all of NGrid's service area, NGrid did not provide evidence of an identifiable net benefit to Rhode Island ratepayers. The Commission is bound to base rates on known and present conditions, *Michaelson v. New England Tel. & Tel.*, 404 A.2d 799, 806 (R.I. 1979), and ensure that the programs supported by those rates directly benefit ratepayers. *Providence Gas Co. v. Malachowski*, 656 A.2d 949, 951 (R.I. 1995). Because the Commission is unable to determine based on the evidence what the costs of the proposed GIS underground project will be, or what the scope of that project will be, the Commission is unable to ascertain any direct ratepayer benefit. Therefore because there is not sufficient evidence to justify inclusion of this cost in the revenue requirement, the Commission denies the request to include funding for this program.

15. Costs to Achieve

The Company's proposed calculation of net savings subject to 50/50 sharing was based on eight years remaining of the ten year amortization of costs to achieve ("CTA") or $2.1 million per year. The Company also requested approval to establish a regulatory asset for merger CTA and associated amortization. The Division adjusted the Company's proposed expense to $924,000 noting that the actual costs incurred during the first two

[76] Transcript of Hearing, Testimony of John Pettigrew, November 3, 2009 at p. 52.

years were covered by savings and therefore, the total remaining amount to amortize was necessarily less.

The Commission relies on Mr. Effron's testimony that the Company experienced savings of approximately $9.5 million during the first two years after the KeySpan merger, which exceeded the costs to achieve of approximately $8.6 million for these same two years. Thus any allowance for the entire costs during years one and two would result in double recovery of some costs, a result squarely at odds with standard ratemaking principles. Accordingly, the Commission finds Mr. Effron's recommendation to deduct these costs from the total CTA of $16,005,000 for a total of $7,395,000 to be amortized over the remaining eight years[77] to be appropriate and reasonable. Mr. Effron also testified during the hearing that the savings associated with this merger were more than adequate to absorb the costs.[78] The Commission agrees. The Commission further finds that NGrid provided no evidence to rebut Mr. Effron's statement that savings exceeded costs for years one and two. The Company, in response to Mr. Effron's testimony, adjusted its request and proposed that the Commission split the excess savings and adjust the request downward by $588,000. Again, the Commission finds Mr. Effron's testimony convincing and supported by the evidence and finds no basis in the record to support the Company's request for mitigating the Division's final recommendation by $588,000.

The Commission also finds that NGrid should be allowed to create a regulatory asset in accordance with FAS 71 to account for the levelized amortization CTA over a ten year period to be included in its cost of service. The Commission will also require proof

[77] Exhibit Div-1 at pp.22-23.
[78] Transcript of Hearing, Testimony of David J. Effron, November 5, 2009 at p. 214.

of continuing savings as a prerequisite to the Company continuing to include the shared savings line item in its revenue requirement for any rate case after four years from the present case.

B. Uncollectible Expense

1. Distribution

The Company proposed a bad debt ratio of 1.1% which is the two year average of its actual net charge off experience. It claimed that its increase in uncollectible expenses is driven largely by the increase in commodity costs and the overall state of the economy, both factors which are beyond the control of the Company. The Division recommended the Commission set a bad debt ratio of 0.71% blaming the increase in uncollectible expense on the Company's lack of proper collection practices. The Division asserted that NGrid did not implement its bad debt strategy until "mid 2008" and has allowed past due balances for both residential and non-residential customers to grow to levels that are no longer realistically recoverable. The Division pointed out the Company's policy of not shutting off non-protected residential customers during the winter even though it is within the Company's right to do so. The Division also pointed out a number of debt mitigation strategies that could be employed by the Company, including requiring security deposits.

The Commission understands the balance that must be maintained in determining whether to terminate a customer's service and is mindful of the individual circumstances of each customer and how those circumstances are often very different. The Commission, however, agrees with the Division that the Company should be more proactive in its collection activities. The Commission does not agree with the Company that the primary reason for the increase in its uncollectible expense is the state of the economy and the increase in commodity costs. While this may be a contributing factor, the Company is also responsible for its collection practices. The number of customers and the large amounts of charge offs are evidence of the Company's failure to actively manage its uncollectible expense. Although the Commission appreciates that the Company has stepped up its collections procedures, it believes that NGrid can do more to control its uncollectible expense and that this expense would not have been so large had the Company acted sooner. The Commission does not believe that the 0.71% proposed by the Division is reasonable for the Company but also does not believe that the two year average proposed by the Company to be reasonable either.

The Commission has addressed the problem of the Company's uncollectible expense previously. *In Re: New England Gas Co.'s Gas Cost Charge*, Docket No. 3436, Order No. 17606 (issued November 21, 2003)(where the Commission suggested a $1,000 maximum balance as acceptable), *New England Gas*, Docket No. 3436, Order No. 17979 (issued August 20, 2004)(where the Commission warned that failure to pay must result in consequences). The Division also noted NGrid's agreement to accept a lower bad debt allowance percentage that declined over a four year period in New Hampshire as evidence that the Company is aware of its imprudent management over its accounts receivables. *In Re: EnergyNorth Natural Gas, Inc., d/b/a National Grid NH*, DG 08-009, Order No. 24,872 (May 29, 2009). Furthermore, the evidence provided by the Company showed numerous residential and non-residential accounts with extremely high balances allowed to go without disconnection for months.[79]

The Commission has historically used multi-year averaging of the Company's actual experience in base rates in order to mitigate year to year variations. Narragansett

[79] Exhibit Div-24, Exhibit Div-2 at pp. 24.

Electric Company, Docket No. 3943, Order No. 19563 at p. 50. The Commission finds that a five year average or 0.94%, is reasonable. This will acknowledge the Company's efforts since 2008 as well as address the Company's failure to implement proper collection practices.

2. Commodity

Both the Company and the Division assert that it is appropriate to recover commodity-related bad debt through Standard Offer Rates, a methodology very similar to what is allowed for the Company's gas operations. The Commission finds this to be reasonable and finds that fixing the commodity-related bad debt ratio in base rates is not inconsistent with the Commission's treatment of commodity costs which are recovered on a pass-through basis, because the Company has the ability to develop and implement measures to lower the uncollectible ratio. Therefore, the Commission finds that the recovery of commodity-related bad debt expense shall be allowed through Standard Offer Rates using the mechanism approved in Docket No. 3943 using a five-year average of bad debt ratio of 0.94%.

3. Transmission

The Company and the Division both agreed that it is appropriate to recover transmission-related bad debt through transmission rates. The Commission agrees with the Company and the Division and finds that the recovery of transmission-related bad debt should be provided through transmission rates rather than through distribution rates.

4. Bad Debt Reconciling Factors

The Company proposed that the bad debt allowance for delivery-related costs be set at a fixed level. However, that level would be adjusted if the actual bad debt exceeded the amount built into rates by more than $500,000, provided that the Company made at least 510,000 outbound calls and 41,000 field visits and the increase was caused by factors beyond the Company's control such as regulatory or legislative action, increases in standard offer rates, unemployment, etc. The Company also proposed that bad debts associated with Standard Offer and Transmission also be reconciling. The Division urged the Commission to reject these provisions pointing out that this type of mechanism is not in place for gas operations and it would further shift risk to ratepayers and would serve to remove the incentive for the Company to manage its bad debt expense.

The Commission has historically used a multi-year average of the Company's actual experience in base rates in order to mitigate year to year variations and finds that the annual reconciliation of commodity related bad debt costs is not in the best interest of ratepayers because it has the potential to amplify price volatility for customers. *Narragansett Electric Company*, Docket No. 3943, Order No. 19563 at p. 50. The Commission believes that implementation of a reconciling mechanism will remove the incentive the Company has to manage its bad debt expense. Therefore, the Commission denies the Company's request for the reconciling mechanisms for bad debt expense.

C. Rate Base

1. Forecasted Capital Additions

NGrid proposed plant in service through rate year 2010 of $1,232,477,804. The Division recommended reducing this amount by $19,953,000. The Commission finds the Division's recommendation reasonable and supported by the testimony of its witness. Specifically, the Commission finds that the actual additions to plant in service in recent years were less than the additions forecasted by the Company. Specifically, Mr. Effron presented evidence that was unrebutted by the Company that from January to July 2009, the Company spent an average of $4 million per month on plant additions.[80] The Commission has previously required the Company to establish that its capital projects will be used and useful by the end of the rate year. An expectation that a project will be placed in service during that time is not sufficient. *Providence Gas Co.*, Docket No. 2286, Order No. 14859 (issued February 16, 1995) at p. 21. *See also South County Gas Co.*, Docket No. 1671, Order No. 10905 (issued October 15, 1982) at pp. 20-21 (where there is no evidence supporting the specifics of a capital project, the projection of plant growth is nothing more than speculation).

Previously, the Commission has adopted the Division's recommendation of actual construction costs when it has been shown that the Company's actual levels are below their budgeted rate year levels. *In Re Tariff Filing by Narragansett Electric Co.*, Docket No. 1659, Order No. 10901 (issued March 30, 1983) at p. 20. The Commission finds that Mr. Effron's testimony is further supported by NGrid's response to a Division Data Request showing a shortfall in actual plant additions continuing through September 2009.[81]

This Commission will not require ratepayers to pay for costs that are not likely to occur. The Division's analysis reflected the most recent data and its recommendations are based on the evidence provided by NGrid. What is surprising to the Commission is NGrid's lack of effort to provide updated and current figures and calculations in a number of instances and to provide inflated projections similar to what it did in Docket

[80] Exhibit Div-1 Testimony of David J. Effron at 28, Exhibit Div-8 Surrebuttal Testimony of David J. Effron at 12.
[81] Exhibit Div-8 at p. 12, Exhibit NGrid-55, Response 23-5, Exhibit NGrid-59, Response 27-2.

No. 3943, where the Division proposed reducing the Company's proposed capital expense to reflect current actual expenses that were not at all reflective of the pace at which capital projections could actually be completed in the rate year. *See also*, *Blackstone Valley Electric Company*, Docket No. 1605, Order No. 10695 (issued May 12, 1982). This finding parallels Mr. Moul's failure to update his figures and calculations to provide the Commission with the most recent and current data upon which to base its decision. In another instance, the Company, when asked about the total cost of each Information Services project and NEC's assigned share of the cost for each project, acknowledged overstating this expense by approximately $180,000.[82]

The Commission finds that the Division's recommendation is reasonable, credible and supported by the evidence. The Commission finds the Division's recommendation to be more realistic based on the actual plant additions and finds it will ensure that ratepayers are not paying more for plant costs than what the Company will realistically incur during the rate year. The Commission has previously held that capital projects must be shown to be used and useful by the end of the rate year. *Providence Gas Co.*, Docket No. 2286, Order No. 14859 at p. 21. The Commission accepts the Division's recommendation resulting in the calculation of the average rate year balance of plant in service for the rate year of $1,212,525,000 or $19,953,000 less than the Company's forecast.[83] The Commission finds this to be consistent with previous Commission decisions adopting the Division's recommendation based on actual construction levels when they are lower than the Company's projected levels. *In Re Tariff Filing by*

[82] NGrid Response to Commission Data Request 13-7.
[83] Exhibit Div-1 at p. 29, Div-8 at p. 12, DJE-8S, 8.1S.

Narragansett Electric Co., Docket No. 1659, Order No. 10901 (issued March 30, 1983) at p. 20.

2. Accumulated Depreciation

For 2009 and 2010, NGrid estimated plant additions and in calculating accumulated depreciation, it applied the actual historical relationship between plant retirements and the cost of removal. The Division recommended that for 2009, the starting point be the actual accumulated depreciation balance as of June 2009 reflecting the net change in depreciation expenses, plant retirements and the cost of removal as of June 30, 2009. The same net change in accumulated depreciation for the second six months of 2009 was projected. For 2010, the Division recommended using the approach recommended by the Company. Like the rationale in the above section, the Commission finds that relying on actual data to determine rate year plant in service is fairer to ratepayers than using estimates. Given the availability of data, the Commission finds that the Division's recommendation for the calculation of accumulated depreciation for the second half of 2009 to be supported by the evidence since it relies on the most updated actual information.

3. Accumulated Deferred Income Tax

Prior to the Commission's open meeting on this matter, the Company indicated to the Commission that it was in agreement with the Division's recommendation regarding the calculation of accumulated deferred income taxes ("ADIT") through June 30, 2010. The Commission finds this method reasonable noting again that the use of actual figures produces a more accurate and realistic projection for predicting the rate year revenue requirement.

4. Cash Working Capital

NGrid proposed that Contract Termination Charges (CTC) should be included in Cash Working Capital (CWC) and included $371,000 in rate base. The Division opposed this proposal noting that the $371,000 for CTC is recoverable through a reconciling charge with over or under recoveries subject to interest calculations at the customer deposit rate and that the revenue impact is $45,000. The Commission agrees with the Division's rationale and evidence presented and finds that because the CTC is recoverable through a reconciling mechanism it should not be included in CWC.

The Company also requested that the CWC balance associated with municipal taxes be $6,783,000 and that the payment lag be based on the service period reflecting the municipal tax period twelve months ending June 30 and not on the rate year. The Division recommended reducing CWC associated with municipal taxes by almost $10 million and maintained that the balance should follow the same method approved by the Commission in Docket No. 3943, which used the service period of January through December. The Commission finds difficulty in reconciling Mr. O'Brien's claim that the money for municipal taxes are collected from ratepayers approximately 123 days after that money is paid to the city or town[84] when the actual practice for gas operations reflected that taxes were collected from ratepayers on an average of 32 days prior to making the payment.[85] Additionally, the Division used the Company's exhibit, RLO-4 p. 7, to calculate the average payment lag percentage rate of -16.19%. The Company did not explain to the Commission why it needs this calculation to be materially different for electric and gas operations. The Commission finds the Division's argument persuasive

[84] Exhibit NGrid-9 at p. 38.
[85] Exhibit Div-1 at p. 32.

that the lag period proposed by NGrid is not consistent with the accounting method upon which the Company's expenses are determined for book and ratemaking purposes.[86] The Commission finds that it is appropriate and reasonable to recognize that NGrid has the use of substantial ratepayer dollars prior to actually making tax payments. Therefore, the Company's rate request for CWC related to municipal taxes shall be reduced by $9,893,000.

III. PENSION AND OTHER POST EMPLOYMENT BENEFITS RECONCILIATION MECHANISM

The Company proposed a mechanism to recover pension and other post employment benefits expense incurred each year over the amount included in base rates. The Division had no opposition to this mechanism. It is important to note that in Docket No. 3943, two of the three Commissioners approved this reconciling mechanism over the Division's objection. In that case, the Division argued that reconciling mechanisms are generally contrary to sound ratemaking principles, except for costs with large fluctuations beyond the Company's control that jeopardize its financial integrity. The majority of the Commissioners in Docket No. 3943 disagreed with the Division and granted the Company's request for the reconciling mechanism.

The current majority agrees with the statement of Mr. Effron in his direct testimony where he discussed reconciling mechanisms and noted that they are appropriate only for exceptional expenses that are large, volatile and beyond the utility's control.[87] In this case unlike in Docket No. 3943, the Commission finds that the Company did not establish that its historical pension and OPEB expenses fluctuated in an unmanageable amount. The largest annual fluctuation was a $4.2 million decrease in

[86] Exhibit NGrid-8 at p. 15.
[87] Exhibit Div-1 at p. 14.

expenses from 2008 to 2009. A $4.2 million fluctuation for a company with an allowed cost of service of $239 million net of miscellaneous revenues is only 1.75%, a manageable business risk in the opinion of the Commission. The Commission included $13.6 million based on the company's estimate of its Rate Year Expense projection, covering the $8 million projected increase.[88] The Commission sets rates based on rate year expenses absent a multi-year rate plan and sees no reason to include a reconciling provision in this case. Moreover, the Company conceded that it has some ability to control pension and OPEB costs.[89] For example, it can control the type of plan it offers and it can control how generous the plan is to employees. In fact, in Docket No. 3943, the Company represented to the Commission that it planned to make further efforts to control pension and other post employment benefits which is evidence that the cost is within the control of the Company. Additionally, the Company provided no evidence that the current funding method is inadequate. The Commission also notes that there was not a scintilla of evidence to support that a denial of the proposed reconciling mechanism would jeopardize the Company's financial integrity or well-being and no evidence demonstrated that the proposed reconciling mechanism would provide any benefit to the ratepayers.

Furthermore, the Commission finds that this expense is a business risk that should be managed by the Company like any other business risk facing a business enterprise. Also important to note is that the State of Rhode Island, whose pension fund is severely underfunded, has not proposed that the Rhode Island taxpayers be burdened with a reconciling mechanism to ensure adequate funding of the state pension program. The

[88] Exhibit NGrid-9 at p. 62.
[89] Exhibit NGrid-9 at p. 60.

General Assembly has proactively modified the existing plan to address this underfunding by changing the benefit eligibility, increasing the level of employee contributions, among other options under consideration. The Company should adhere to the same proactive approach to ensure proper funding of its plan. Furthermore, unlike the record in Docket No. 3943, there was no evidence in this case that the Company has had a history of funding its pensions at a level less than the full amount allowed in rates.

This Commission is perplexed that the prior Commission would allow for a reconciling mechanism for a pension program that was 97% funded even in light of the Company's representation in Docket No. 3943 that NGrid planned to make further efforts to control pension and other post employment benefits. The Company's own statement in that case acknowledged that this expense is not outside of the control of the Company. If the Company is controlling this expense through its cost containment efforts then it should be commended and encouraged to continue to find ways to further control these costs for all of its operations in Rhode Island.

Based on the above, the Commission finds no basis for the Company's proposed reconciling mechanism and, accordingly the Company's request for a pension and other post employment benefits reconciliation mechanism is denied. Furthermore, the fact that the Commission in Docket No. 3943 approved this expense does not bind the current Commission from denying it when there is not sufficient evidence in the record to support ratepayers paying for this expense. As previously stated throughout this order, the Commission is not bound to use a particular method relied upon in a previous case. *Michaelson v. New England Tel. & Tel.*, 404 A.2d 799 (R.I. 1979)(where the Court found the Commission was not bound by either factual determinations or methods utilized in a prior docket).

IV. REVENUE DECOUPLING

The Company proposed a revenue decoupling ratemaking plan ("RDR Plan"). Within the RDR Plan are two components referred to by the Company as a "look back" component and a "look ahead" component. Within the two components are trackers to adjust for capital expenditures and inflation on operating expenses and an annual revenue reconciliation mechanism. All of the components combine to create an adjustment factor that, when added to base rates, produce class distribution rates. ENE, CLF and EERMC supported the Company's proposal. The Division objected to the Company's RDR Plan in total as did TEC-RI and the GWC.

All of the parties provided extensive testimony and argument in support of their positions; however, the Commission finds the arguments of the Division, particularly Mr. Oliver's testimony and TEC-RI, the testimony of John Farley, to be most persuasive. The Company did not convince the Commission that revenue decoupling will produce energy conservation beyond what is already being achieved under the Company's demand-side management ("DSM") programs or that the Company is not capable of maintaining its commitment to comply with the statutory mandate that it implements cost-effective DSM programs. Furthermore, NGrid did not present any evidence that ratepayers will not engage in energy efficiency absent revenue decoupling, or that decoupling will produce more energy efficiency or that energy efficiency has prevented the Company from obtaining revenues sufficient to operate its electric distribution system. NGrid did not present any evidence that traditional ratemaking is insufficient to operate its electric distribution system. Finally, the Commission finds that NGrid did not provide sufficient evidence that its revenue decoupling proposal is in the best interest of ratepayers or that it even provides a commensurate benefit to its ratepayers to compensate them for the additional risk that revenue decoupling would shift from the NGrid shareholders to the ratepayers. Based on the above, the Commission denies the revenue decoupling ratemaking plan in total.

The Company did not convince the Commission that revenue decoupling will produce energy conservation beyond what is already being achieved under the Company's demand-side management ("DSM") programs or that the Company is not capable of maintaining its commitment to comply with the statutory mandate to implement cost-effective DSM programs. Mr. Stout testified about the Company's energy efficiency programs. He acknowledged that the Company is ranked ninth in the country in terms of energy efficiency programs.[90] When questioned, Mr. Stout admitted that even without revenue decoupling, NGrid's DSM programs "can and will be effective."[91] He pointed out the "long record of implementing effective programs"[92] which the Commission notes and Mr. Stout admitted that the programs have long been in existence and highly successful without revenue decoupling. Further, he did not provide the Commission with any evidence that the Company would implement new programs if revenue decoupling were approved. Although Dr. Tierney provided extensive testimony to the Commission about revenue decoupling and the Company's proposal, she was unable to establish whether the Commission's approval of the Company's proposal

[90] Transcript of Hearing, Testimony of Timothy Stout, November 5, 2009 at p.218.
[91] *Id.* at 220.
[92] *Id.*

would result in additional benefits to ratepayers or better energy efficiency programs.[93] Dr. Tierney, like Mr. Stout, did not provide the Commission with any evidence that established detailed, positive and definite effects that the implementation of revenue decoupling would have on ratepayers in terms of increased participation in energy efficiency programs.

The Commission is not persuaded by the extensive testimony regarding other states' decisions to adopt some form of decoupling mechanisms. The Commission finds the Division's representation that revenue decoupling is a "minority position" to be accurate and reflective what other states have done. The Company's representation that as of May 2009 ten states had adopted revenue decoupling for electric utilities is evidence of this minority status.[94] The fact that Rhode Island has achieved a ranking in the top ten states for energy efficiency without revenue decoupling is powerful evidence that revenue decoupling is unnecessary for NGrid to achieve its energy efficiency goals. Additionally, the Commission takes particular note of the fact that Rhode Island is ranked higher than two other jurisdictions that have revenue decoupling, namely, Wisconsin and Maryland.[95] The above facts also support the Commission's finding that NGrid did not present any evidence that it could not maintain its commitment to comply with its statutory mandates to provide effective DSM programs absent revenue decoupling. Mr. Stout's testimony alone, that even without revenue decoupling the Company's programs will be effective, supports the finding that that revenue decoupling is not necessary in

[93] Transcript of Hearing, Testimony of Susan Tierney, November 5, 2009 at pp. 164.
[94] The Commission notes that of the nine states that have implemented some form of revenue decoupling as of September 2009, at least two require a true-up of costs as well as revenues, one includes the utility meeting performance goals in energy efficiency, and another has caps. Finally, one state only reconciles revenues associated with fixed costs. Only one state, Massachusetts, has implemented the type of RDR sought by NEC. PEW Center on Global Climate Change, www.pewclimate.org
[95] RR-Comm-15.

order for NGrid to comply with the requirement that it provide effective energy efficiency programs.

NGrid did not present any evidence that ratepayers will not engage in energy efficiency absent revenue decoupling or that ratepayers will engage in more energy efficiency if revenue decoupling is implemented. When asked, Dr. Tierney was unable to quantify how the approval of the mechanism would lead to "full engagement and participation in EE programs…."[96] This Commission believes that commodity costs will have a greater impact on a customer's incentive to conserve because reduced usage will result in lower bills as commodity charges comprise a large portion of a customer's bill. The Company also failed to establish to any degree that the absence of revenue decoupling has prohibited it from obtaining revenues sufficient to operate its electric distribution system. Traditional ratemaking allows the Company the ability to obtain funding to properly operate its distribution system. There was not a scintilla of evidence presented by the Company that traditional ratemaking is ineffective. Therefore, the Commission finds no reason to depart from it.

Nowhere in the record is there any evidence that NGrid's energy efficiency programs have prevented the Company from obtaining revenues sufficient to operate its electric distribution system. In fact, the legislature has provided that NGrid be compensated for its DSM programs in terms providing for ratepayer funding for the programs themselves and for the administration of the programs in terms of allowing the Commission to authorize a financial incentive to shareholders based on the success of the

[96] Transcript of Hearing, Testimony of Susan Tierney, November 4, 2009 at p. 164.

programs.[97] It is the opinion of the Commission that the financial incentive should eliminate the claimed disincentive for the Company to promote conservation, a disincentive that his been overcome by the Company's top ranked programs. Furthermore, the fact that decoupling may eliminate a disincentive for the Company to further promote energy efficiency beyond what is being done without decoupling, does not guarantee "a significant reduction in consumption above what would have been achieved as a result of local and national economic pressures, technology improvements and other extrinsic factors." *Narragansett Electric Company*, Docket No. 3943, Order No. 19563.

NGrid disagrees with the Division's and TEC-RI's arguments that implementation of a revenue decoupling mechanism would shift risk from the shareholders to the ratepayers. The Company asserts that risk will not be shifted but will be shared. The Company's current position is remarkably different from the Company's testimony in Docket No. 3943 cited in the Commission's order that decoupling would reduce the Company's revenue risk to zero and shift the risk of revenue variations to ratepayers. *Narragansett Electric Company*, Docket No. 3943, Order No. 19563 at 70. The Commission finds the testimony of Mr. Farley that risk is shifted to ratepayers to be convincing and compelling.[98] As the Company has failed to acknowledge the shift of risk, it is not surprising to the Commission that it did not provide any a commensurate benefit to its ratepayers to compensate them for the additional risk that revenue decoupling would shift from NGrid shareholders to these ratepayers.

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[97] R.I. Gen. Laws §39-2-1.2. For the years 2006, 2007 and 2008, the Company earned a total of $2,151,980 in incentive compensation. Docket Nos. 3710, 3779 and 3892.
[98] Transcript of Hearing, Testimony of John Farley, December 2, 2009 at p. 43.

The Commission finds that the various adjustments associated with NGrid's proposed RDR Plan move toward eliminating the controls and protections afforded by traditional ratemaking. If the Company believes that its revenue requirement is not sufficient to support its operations, then it has the option of filing a rate application with the Commission. The Commission finds that the various adjustments provide the Company with the ability to avoid rate cases while still having the ability to realize higher rates in the future. The Commission agrees with the Division's analysis of the inflation adjustment mechanism and finds that the Commission's Rules governing the processes for rate applications specifically prohibit the inflationary adjustment proposed by the Company. Specifically Rule 2.6 prohibits increases unless the utility presents a cost of service for a test year period consisting of historical data within nine months of the filing date. The automatic inflation adjustment violates this Rule. The Company's reliance on *Providence Gas v. Burke* and *Michaelson v. N.E. Tel. and Tel.* is misplaced and the Commission does not believe that the Court intended to condone automatic inflation adjustments as permissible but intended that the Commission determination of an appropriate rate consider, on a case by case basis, an inflationary impact that may occur.

Furthermore, the Division is correct in its argument that the Commission does not have the authority to approve capital expenditures that are not used and useful. The Court has prohibited a utility from including these costs in rate base. *Newport Electric Corp. v. Public Utilities Comm'n*, 624 A.2d 1098, 1103 (R.I. 1993). The Commission agrees with Mr. Oliver's statement that the prudent, used and useful standard requires that "such determinations be made before costs for capital additions are included in rates" and that the Company's "look ahead" portion of its RDR Plan does not allow for this.[99]

The Company did not present sufficient evidence to support its proposal for a Capital Expenditure Tracker ("CAPEX") to annually reconcile capital expenses. In Docket No. 3943, Order No. 19563, the Commission approved an Accelerated Replacement Program for cast iron and bare steel mains because they were prone to gas leaks and created substantial safety and environmental issues. The evidence in that case strongly supported the safety argument. In the instant matter the Company provided no evidence of environmental or safety issues that would warrant a departure from traditional ratemaking. Additionally, the Company provided no evidence that it was unable to meet its proposed capital budgets without a CAPEX tracker. In fact, the evidence showed that during the test year, the Company dramatically increased capital spending which was significantly ramped up in the rate year.[100] With top quartile reliability existing since 2006, it is unclear to the Commission why such a significant ramp-up was necessary. The Commission finds Mr. Hahn's testimony convincing and compelling in pointing out the significant increase in spending in the test year as compared to 2007 and 2008.[101] The Commission has already found that the Company's forecasted plant additions were higher than what was actually occurring and accepted the Division's recommendation to adjust the test year to properly reflect the actual expenditures. The Commission finds Mr. Hahn's claim that the unadjusted test year costs already support the capital additions anticipated by the Company's rate year capital

[99] Exhibit Div-5 at 47.
[100] Exhibit Div-10 at 12-13.
[101] Exhibit Div-10, Table 1 at p. 13.

budget convincing and supported by the evidence.[102] Based on the state of the record, the Commission finds that the Company presented a very weak case to support its need for a CAPEX tracker.

In totality, the Company did not present sufficient evidence that its RDR Plan is in the best interests of all ratepayers. The Commission finds that Mr. Oliver's criticism of the proposal is convincing. The Commission finds Mr. Oliver's testimony that NGrid's proposal to use a single uniform cents per-KWh rate adjustment for all classes will result in a disproportionate share of the burden for adjustments on customers within each class that have a comparatively large kWh requirements to be persuasive.[103] The Commission also finds that in order to depart from traditional ratemaking, it needs more than speculative assertions that the implementation of decoupling will promote additional energy efficiency and conservation, more than claims of a growing trend among sister states, and more than an assertion that risk will be equally shared as opposed to a unidirectional shift to ratepayers from shareholders. Additionally, the Commission will not depart from traditional ratemaking unless it can be fully established that traditional ratemaking does not work. Based on the foregoing discussion and the fact that the Company did not provide sufficient evidence to justify the Commission departing from traditional ratemaking, the Commission will deny the Company's RDR Plan proposal in total.

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[102] *Id.* at p. 12.
[103] Exhibit Div-5 at p. 50.

V. COST ALLOCATION

1. Minimum System Study

Both the Navy and TEC-RI requested that the Commission require a Minimum System Study prior to the next case to allocate costs to demand and customer components. The Division recommended that the Commission reject this request. The Commission is satisfied by Dr. Swan's reasoning[104] that it deny the request for a minimum system study and as such, rejects the request. This is consistent with the Commission's previous ruling in *In Re: Narragansett Electric Co.*, Docket No. 1606/1692, Order No. 11227 (issued April 30, 1984) at p.7.

2. Transformer Cost Allocation

NGrid proposed allocating line transformer costs based on equal weighing of the number of customers and load size.[105] The Division recommended that the Commission deny this proposal and that line transformer costs and associated O&M expenses be classified as demand-related and allocated on class non-coincident peak demands. The Division also recommended that the Lighting class be required to share in these costs. The Commission finds Dr. Swan's argument supporting the Division's position to be persuasive. Particularly, the Commission agrees with Dr. Swan that the Company's proposal ignores the principles of cost causation in that it does not make any allowance for the different sizes of customers in terms of their loads and places these costs on customers who may not be responsible for them, which the Commission finds creates an unfair result. Because there was no direct relationship between the number of customers and the costs or maintenance of the transformers, the Commission accepts the Division's

[104] Exhibit Div-7 at pp. 9-10.
[105] NGrid's original proposal allocated line transformer costs by direct assignment. In its rebuttal, the Company proposed the compromise set forth above.

recommendation that line transformer cost be allocated based on average percentage class responsibilities for the non-coincident peak at primary and secondary voltages. The Commission also finds that the Lighting class should share in these costs.

3. Uncollectible Expense Allocation

a. Delivery-Related

The Company proposed allocating $4.3 million in distribution-related uncollectible expense to those rate classes under which the original charges were assessed and ultimately charged off noting that it is appropriate to allocate bad debts to the classes that caused the bad debt, properly reflecting the costs of serving those classes. The Division recommended that uncollectible expense should be allocated to all customer classes based on total delivery revenue and that bad debts are a general cost of doing business and should be allocated using a general allocator such as class revenue. In its rebuttal, the Company noted that if the Commission were to approve the Division's position, the allocation should be based on rate year revenue rather than test year revenue. The Division did not object to this modification.

The Commission believes that all customers should be allocated a share of uncollectible expense and that such expense is a cost of doing business. It is unfair to saddle the members of a particular class with this expense when those members have no control of it and have not individually contributed toward it. The Commission believes it is fair and reasonable that all customers be allocated a share of uncollectible expense based on rate year revenue as using the rate year will provide more updated figures.

b. Commodity-Related

NGrid proposed allocating commodity-related bad debt expense through SOS on the basis of rate class under which charges were assessed and ultimately charged off. The Division recommended allocating this expense to all customer classes based on Total Commodity Revenue or SOS-related kWh deliveries. TEC-RI supported the Company's proposed allocation. The Commission finds the Division's position fair and reasonable. These costs are a cost of doing business that should be borne by all customers and not just allocated to the customers of the class where the costs originated, especially because the paying customers of the class have not caused the expense. The Commission finds that these costs should be allocated the same way as delivery-related bad debt in that all customers should share in this expense based on total commodity revenue for the rate year.

c. SOS-Related Administrative Costs

The Company proposed to recover all SOS-related administrative costs, except Cash Working Capital, through SOS with $6.6 million from the "Small Customer Group" and the remaining amount on equal basis from the "Small Customer Group" and the "Large Customer Group". The Division recommended allocating SOS-related administrative costs, except Cash Working Capital, through SOS on the basis of SOS-delivered energy. The Commission finds that the Division's recommendation provides a fairer allocation of these costs. The Commission agrees with Dr. Swan that an allocation based on SOS-delivered energy will result in an equal cost factor for all classes.

4. Service & Information Expense Allocation

NGrid proposed allocating $5.4 million of Customer Information & Services expenses based on the total number of customers NGrid has. The Division recommended that this allocation be among customer classes based on energy use at the meter. The Commission finds that because these costs are caused by the amount of service provided to a class rather than the number of customers, the appropriate method of allocation should be based on energy use at the meter. The Commission is convinced by Dr. Swan's testimony that the types of services reflected by the Company in these accounts, i.e., supervision, processing inquiries on proper use, replacement and information on electric equipment, advice on the efficient and safe use of electric equipment, demonstrations, exhibits, lectures on safe economical use of conservation, etc., are not directly caused by the number of customers but by the amount of service that is provided to the various classes. The Commission finds the Division's recommendation to be fair and reasonable and as such approves the same.

5. Economic Development Expense Allocation

The Company proposed that the costs for its proposed economic development program be allocated only to the C&I customers on the basis of energy consumption. The Division objected to this and recommended that these costs, if allowed by the Commission, be socialized to all customer classes. As the Commission has denied these costs in total, this issue is moot.

6. Limits on Cost Allocations Among Rate Classes

NGrid proposed limiting the rate increase for the Lighting and Propulsion classes at two times the total Company percentage increase and then allocating the remaining shortfall exclusively to the C&I Large Demand Class. This proposal also includes the

Rate A-60 receiving a proportionate share of the residential increases. The Division found this proposal reasonable with the exception of allocating the shortfall entirely to the C&I Large Demand Class and recommended that the shortfall be allocated to all other classes whose increases are not capped. The Navy and TEC-RI objected to allocating all of the shortfall associated with this limit on the C&I Large Demand Class and agreed with the Division that it should be allocated to all customer classes. TEC-RI also recommended that all Commission downward adjustments be applied to the C&I Large Demand Class to bring it to its cost of service before allocating these adjustments to other classes. Lastly, the George Wiley Center asserted that the Rate A-60 should not receive any increase above current distribution rates.

The Commission is mindful of the difficult economic times being faced not only by residential customers but commercial and industrial customers as well. Since every customer benefits from the services provided by the Lighting Class, it is the opinion of the Commission that every class should share in the shortfall arising from the capping of the increase allowed to this class. The service and benefits provided by the Lighting Class are enjoyed by the Rate A-60 customers just as they are enjoyed by the other classes, and the Commission believes that the Rate A-60 customers should contribute an equal share for these benefits. The Commission however, disagrees with TEC-RI that the C&I Large Demand Class should first be brought to its cost of service with any Commission downward adjustments before those adjustments are allocated to any other class. The Commission also finds that the Propulsion class should be brought halfway to its cost of service given the extent of the subsidies that the Propulsion class has been receiving over the years.

7. Allocation of Low-Income Subsidy

On rebuttal, the Company agreed with the Division's recommendation to maintain the low income subsidy with recovery of $4,795,000 from all customer classes with the exception of the Lighting and Propulsion classes rather than solely Rate A-16 customers as it originally proposed. TEC-RI supported the Division's recommendation. In light of the fact that all of the parties agree and the Commission finds this allocation to be fair and equitable to all customers, the Commission approves the Division's recommendation.

8. Reallocation of Transmission Costs Based on Coincident Peak

NGrid proposed a revenue neutral redesign of transmission rates by reallocating costs to rate classes based on coincident peak, resulting in a shift of $4 million in transmission revenue recovery from the C&I Large Demand class to the Residential Class. The Division recommended mitigating the impact of this proposal by fifty percent by reducing or increasing each class' revenue requirement by half of the resulting increase or decrease in transmission revenues that will result from the proposed reallocation of costs. TEC-RI supported the Company's proposal and opposed the mitigation recommended by the Division.

The Commission agrees with Dr. Swan that adopting the Company's proposal will result in a large total increase for the residential class.[106] The Commission believes that the Division's recommendation to mitigate the rate impact to the Lighting class is consistent with the principles of gradualism and is fair and reasonable.

[106] Exhibit Div-7 at p. 25.

VI. RATE DESIGN

A. Back-Up Rate

TEC-RI proposed eliminating back-up rates. The Commission finds that there was not enough evidence to determine whether the elimination of back-up rates was in the best interest of the Company and all of its customers. The Commission will open a separate docket to evaluate the impact of this proposal.

B. Appropriate Rate Design for Rate G-62 and B-62

NGrid proposed eliminating Demand Rates G-62 and B-62 and transferring the existing customers in those two classes to Rates G-32 and B-32. Additionally, the Company proposed continuing with a per kWh energy charge under the proposed G-32 rate. The Division objected to this proposal and recommended a phased transition move to occur over the course of three to five years. The Division suggested the phase-in to be based on total delivery service cost increases approved in this case and allocating the shortfall among all other customer classes except Lighting and Propulsion in proportion to each class/distribution revenue requirement. TEC-RI opposed the proposal noting that the shift of the B-62 customers to Rate B-32 would result in an unacceptable increase. The Commission finds that the proposed elimination G-62/B-62 class will result in a significant increase in the demand charge of these large customers and even though their customer charge will decrease the demand charge is what drives the greatest impact on a customer costs. The Commission further finds that the Company did not present sufficient evidence to justify the elimination of these two classes or that the elimination would not result in a detrimental impact on these customers. The Commission, therefore, denies NGrid's request to eliminate the G-62/B-62 classes.

The Commission finds that the distribution rate increase for customers with demands greater than 8 MW should be limited to 150% of the average overall rate increase approved by the Commission in this case. The impact of this limit shall be absorbed by the other Large C&I Demand customers. In any event, the impact should be much less than what was assumed had NGrid been allowed to increase rates by approximately $57 million, which reflects the Company's current request by the end of this case. The Commission commends TEC-RI for its active participation in this case. TEC-RI provided timely, complete and thorough information to the Commission upon which the Commission was able to make well-informed decisions. Furthermore, TEC-RI, on behalf of large customers, was willing to absorb its fair share of the low income subsidy. The Commission finds that the commercial and industrial customers have suffered from the financial climate just as much as the residential customers and again commends TEC-RI for its willingness to share in the impacts resulting from the rate increase.

C. Monthly Customer Charge

The Company proposed increasing the customer charge for the Rate A-16 class to $5.50 per month from $2.75, for the Rate C-06 to $10.00 per month from $6.00, for the Rate G-02 to $125.00 per month from $103.41, and an increase in the C&I Large Demand rate class to $980.00 per month from $236.43. The Division recommended that the increase to the Rate A-16 be no greater than an additional $1.00 per month and the increase to the Rate C-06 be no greater than an additional $2.00 per month. The Commission accepts Dr. Swan's argument that these increases will have adverse impacts on the customers in these two rate classes[107] and the principles of gradualism support the recommendation made by the Division.

D. Per kWh Adjustment Factors

The Company proposed a number of per kWh adjustment provisions specifically, a distribution adjustment provision, a pension/OPEB adjustment provision, a revenue decoupling mechanism provision and an inspection and maintenance adjustment provision. As the Commission did not approve any of the adjustment factors proposed by the Company, this issue is moot.

E. Low Income Proposal

NGrid did not make a proposal to continue the annual credit to the Rate A-60 class funded from the Docket No. 3710 settlement and scheduled to end at the end of 2009.[108] In Docket No. 3710, NGrid proposed to utilize $8 million from the proceeds of a settlement agreement to fund a multi-year enhanced low income credit, increasing the distribution credit on the A-60 rate by applying an additional $2 million per year on a per kWh basis for the first 450 kWh used by each customer taking service under the A-60 rate. The commission approved the program for the first year only (CY2006). In 2006, 2007 and 2008, the commission approved the program for the three remaining years (CY 2007, 2008, and 2009). In approving the additional per kWh discount for 2009, the

[107] Exhibit Div-7 at p. 31.
[108] In Docket No. 3710, the Commission approved a settlement agreement between the Company, Division of Public Utilities and Carriers ("Division") and the Attorney General of Rhode Island arising in part out of issues relating to disputes regarding New England Power Company's ("NEP") Contract Termination Charge ("CTC") ("CTC Settlement"). The agreement provided that $2 million would be refunded to the A-60 rate class through a uniform per kWh distribution credit on the first 450 kWh of usage in 2006. The A-60 rate class' $2 million distribution credit would also continue through the period 2007 through 2009, for a total additional credit of $8 million. The credit factor would be adjusted each year to take into account any increase or decrease in the A-60 rate class load in order to protect against a deferral which the Company would expect to recover from all customers at the end of 2009.

commission stated, "in the event a balance remains in the CTC Settlement account such that there are funds remaining to be disbursed at the end of 2009, the Commission will consider proposals in the next Annual Reconciliation filing by the company regarding the appropriate application of those remaining funds in 2010."[109]

In Docket No. 4140, filed on January 11, 2010, the Company proposed to credit the remaining $995,978 remaining in the fund to the enhanced low income credit to reduce the fund to zero. The company further proposed that the balance in the account at March 31, 2011, whether positive or negative, be credited to or collected from all customers through the transition reconciliation. This proposal was supported by the Division through a Memorandum to the Commission dated January 28, 2010. A hearing on the matter was held in Docket No. 4140 on February 3, 2010. The Commission approves the proposal made by NGrid and supported by the Division in Docket No. 4140 and believes that applying the remaining balance in the CTC account to the A-60 customers as an additional per kWh discount of $0.00419, effective on usage on and after March 1, 2010 through April 30, 2011, will assist in alleviating the effect of the increase that class will receive as a result of the Commission's decision in this matter.[110]

Furthermore, because the enhanced low income credit will expire in approximately one year, leaving A-60 customers to face another rate increase on and after April 30, 3011, the Commission finds that it is appropriate to mitigate some of the rate increase that will occur as a result of the expiring low income enhancement credit by reducing the class revenue requirement by one half of the annualized credit amount, or $0.9 million to take effect on May 1, 2011. The Commission believes that this

[109] Order No. 19623 (issued April 20, 2009).
[110] The per kWh discount was approved at an Open Meeting on March 1, 2010 when the Commission approved NGrid's Consolidated Compliance Filings made in this docket and in Docket No. 4140.

determination is consistent with the principles of rate gradualism and reasonable in that it will help to mitigate the effect of the increase that the A-60 class will receive as a result of the Commission's decision in this matter.

ACCORDINGLY, it is

(19965A) ORDERED:

1. The Narragansett Electric Company d/b/a National Grid's request to collect an additional $57,766,125[111] is denied. National Grid is authorized to collect an additional $16,409,000 in revenues on usage on and after March 1, 2010.

2. The Narragansett Electric Company d/b/a National Grid is authorized to collect total distribution revenues of $246,748,967 consisting of:

Base Distribution Revenue	$231,952,274
Commodity Costs Tracker	$ 6,059,653
Transmission Related Uncollectible	$ 1,057,885
Other Revenue	$ 7,679,155

3. The Narragansett Electric Company d/b/a National Grid is allowed a rate year rate base of $550,870,432.

4. The Narragansett Electric Company d/b/a National Grid is allowed an overall rate of return of 7.2%.

5. The Narragansett Electric Company d/b/a National Grid's proposed capital structure is denied. The capital structure approved for ratemaking purposes shall be comprised of 42.75%

[111] This amount is exclusive of the commodity cost tracker and transmission-related uncollectibles.

equity, 52.08% long term debt, 4.98% short term debt and 0.19% preferred stock.

6. The Narragansett Electric Company d/b/a National Grid's proposed cost of capital is denied. The costs of common equity shall be 9.8%, long term debt shall be established by the mechanism agreed to between NGrid and the Division, short term debt shall be 1.60% and preferred stock shall be 4.50%.

7. The Narragansett Electric Company d/b/a National Grid's request for a $2,409,195 adjustment to incentive compensation shall be reduced to $1,204,000.

8. The Narragansett Electric Company d/b/a NGrid's request for a pro forma change to wage costs for new hires is denied.

9. The Narragansett Electric Company d/b/a NGrid's request to maintain $1,041,000 of annual funding of the Storm Fund is denied and is suspended until such time that the balance of the account falls below a threshold of $20 million at which time funding will be reinstated, subject to Commission approval.

10. The Narragansett Electric Company d/b/a National Grid's request to include the test year amount of Storm Damage Expense in the revenue requirement is denied and the Company shall normalize Storm Damage Expense by using a five year average from 2004 through 2008 thereby reducing test year Storm Damage Expense by $1,395,000.

11. The Narragansett Electric Company d/b/a National Grid shall reduce its injury and damage expense by $2.5 million.

12. The Narragansett Electric Company d/b/a National Grid's total rate case expense is approved and the Company shall be allowed to recover this expense amortized over a five year period.

13. The Narragansett Electric Company d/b/a National Grid's four year total of outside legal counsel expense shall be reduced by $593,795 to reflect the elimination of three years of Constellation litigation expense and the revenue requirement shall be based on a four year average of the remaining legal expense for the years 2005 through 2008.

14. The Narragansett Electric Company d/b/a National Grid shall use a five year historical average of vegetation management expense to determine the amount of vegetation management expense to be included in its revenue requirement.

15. The Narragansett Electric Company d/b/a National Grid shall use a four year historical average of inspection and maintenance expense to determine the amount of inspection and maintenance expense to be included in its revenue requirement.

16. The Narragansett Electric Company d/b/a National Grid's request for a reconciling mechanism for inspection and maintenance expense is denied.

17. The Narragansett Electric Company d/b/a National Grid is authorized to collect $800,000 in transformation expense.

18. The Narragansett Electric Company d/b/a National Grid's request to collect $2.3 million of GIS costs allocated from the Service Company is denied.

19. The Narragansett Electric Company d/b/a National Grid's request for a pro forma adjustment of $376,000 for increased collection activities is denied.

20. The Narragansett Electric Company d/b/a National Grid shall reduce merger related costs to achieve by $1,176,000 and may establish a regulatory asset for the remaining amount allowed in rates.

21. The Narragansett Electric Company d/b/a National Grid's request for a pro forma adjustment of $182,000 to fund two new customer advocacy positions is denied.

22. The Narragansett Electric Company d/b/a National Grid's request for $1 million to fund an economic development program is denied.

23. The Narragansett Electric Company d/b/a National Grid shall reduce projected plant in service by $31,877,000 for a reduction in average rate year plant balance of $19,953,000.

24. The Narragansett Electric Company d/b/a National Grid's request for a CAPEX tracker is denied.

25. The Narragansett Electric Company d/b/a National Grid shall calculate accumulated depreciation by using the actual accumulated depreciation balance as of June 30, 2009 and projecting the same net change in accumulated depreciation for the July through December 2009 period. For 2010, plant additions shall be estimated and accumulated depreciation shall be calculated by applying the actual historical relationship between plant retirements and the cost of removal.

26. The Narragansett Electric Company d/b/a National Grid shall calculate accumulated deferred income tax in the manner recommended by the Division.

27. The Narragansett Electric Company d/b/a National Grid's proposal to recover pension and other post employment benefits through a reconciling factor is denied.

28. The Narragansett Electric Company d/b/a National Grid shall eliminate the $371,000 of contract termination charge from cash working capital and shall reduce cash working capital associated with municipal taxes by $9,893,000 and the payment lag for municipal taxes shall be based on the calendar period.

29. The Narragansett Electric Company d/b/a National Grid's proposal for revenue decoupling and a plan and adjustment mechanism for such is denied in total.

30. The Narragansett Electric Company d/b/a National Grid is authorized a bad debt ratio of 0.94% to calculate the amount of delivery-related bad debt in base rates.

31. The Narragansett Electric Company d/b/a National Grid's request for a reconciling mechanism to allow for the future adjustment to delivery-related bad debt is denied.

32. The Narragansett Electric Company d/b/a National Grid shall recover a standard offer related uncollectible expense through commodity rates using a bad-debt percentage of 0.94% and the same mechanism approved in Docket No. 3943 for National Grid's gas business.

33. The Narragansett Electric Company d/b/a National Grid's request to recover transmission-related uncollectible expense through transmission retail rates is approved.

34. The Commission will not require a minimum system study in the next base rate case.

35. The Narragansett Electric Company d/b/a National Grid shall allocate transformer costs based on the average percentage of class responsibilities for the non-coincident peak at primary and secondary voltages.

36. The Narragansett Electric Company d/b/a National Grid shall allocate delivery-related uncollectible expense to all classes on the basis of rate year delivery.

37. The Narragansett Electric Company d/b/a National Grid shall allocate commodity-related uncollectible expense base on total commodity revenue for the rate year.

38. The Narragansett Electric Company d/b/a National Grid shall allocate Standard Offer Service administrative costs, except for cash working capital, on the basis of Standard Offer Service delivered energy. Cash working capital shall be allocated on the basis of commodity revenue.

39. The Narragansett Electric Company d/b/a National Grid shall allocate customer service and information expenses based on energy use at the meter.

40. The Narragansett Electric Company d/b/a National Grid shall allocate the low income subsidy to all customer rate classes.

41. The Narragansett Electric Company d/b/a National Grid shall continue a low income credit of $0.9 million to be recovered from all customers and incorporated into rates.

42. The Narragansett Electric Company d/b/a National Grid shall allocate transmission costs based on the coincident peak.

43. The Narragansett Electric Company d/b/a National Grid shall mitigate the impact of the redesign of transmission rates by fifty percent in the manner set forth above.

44. The Energy Council of Rhode Island’s request to eliminate back-up rates is denied.

45. The Narragansett Electric Company d/b/a National Grid's proposal to eliminate the demand Rate G-62 and Rate B-62 and transfer the customers in those classes to Rate G-32 and Rate B-32 is denied.

46. The Narragansett Electric Company d/b/a National Grid shall limit the distribution rate increase for customers with demands greater than 8 MW to 150% of the average overall rate increase in this matter.

47. The Narragansett Electric Company d/b/a National Grid shall cap the increase to the Lighting class at two times the total company percentage increase and shall move the Propulsion class to halfway to its actual cost of service and any resulting shortfall shall be allocated to all customer classes.

48. The Navy's and The Energy Counsel of Rhode Island's proposal to bring the Large C&I Demand Class to its cost of service before allocating adjustments to other rate classes is denied.

49. The Narragansett Electric Company d/b/a National Grid shall limit the increase on the customer charge to the Rate A-16 to \$3.75/month and Rate C-06 to \$2.00/month.

50. The A-60 class revenue requirement will be reduced by \$0.9 million to take effect on May 1, 2011.

51. The Parties shall act in accordance with all other findings and instructions contained in this Order.

EFFECTIVE AT WARWICK, RHODE ISLAND ON MARCH 1, 2010, PURSUANT TO AN OPEN MEETING DECISION ON FEBRUARY 9, 2010. WRITTEN ORDER ISSUED APRIL 29, 2010.

PUBLIC UTILITIES COMMISSION

Elia Germani, Chairman*

Mary E. Bray, Commissioner

Paul J. Roberti, Commissioner

*Chairman Germani will provide a dissenting opinion to this order subsequent to his review of the same.

2009 Depreciation Rate Study

The Narragansett Electric Company

Prepared by
Foster Associates, Inc.

FOSTER ASSOCIATES INCORPORATED
ECONOMIC CONSULTANTS

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(239) 267-1600 ÅFAX (239) 267-5030

Ronald E. White, Ph.D.
Chairman

April 20, 2009

Ms. Lisa N. Figliozzi
Manager, Plant Accounting
NATIONAL GRID USA
25 Hub Drive
Melville, NY 11747

RE: 2009 Depreciation Rate Study

Dear Ms. Figliozzi:

Foster Associates is pleased to submit our report of a 2009 Depreciation Rate Study for The Narragansett Electric Company (NEC). This report presents the results of our review leading to a recommendation that NEC seek regulatory authorization to adopt straightï line, vintageï group, remainingï life rates and record depreciation expense using primary account accrual rates developed in the 2009 Study. The recommended accrual rates are equivalent to a composite rate of 3.20 percent compared with a currently approved composite rate of 3.34 percent.

The following table provides a comparison of current and proposed depreciation rates and accruals for calendar year 2009, based upon plant investments and deprecation reserves at December 31, 2008.

Function	Accrual Rate Current	Accrual Rate Proposed	Accrual Rate Difference	2009 Annualized Accrual Current	2009 Annualized Accrual Proposed	2009 Annualized Accrual Difference
A	B	C	D=C-B	E	F	G=F-E
Transmission	2.29%	2.20%	-0.09%	$ 5,232,396	$ 5,038,030	$ (194,366)
Distribution	3.53%	3.35%	-0.18%	37,932,216	36,085,736	(1,846,480)
General	4.07%	4.19%	0.12%	2,309,090	2,375,638	66,548
Total	3.34%	3.20%	-0.14%	$ 45,473,702	$ 43,499,404	$ (1,974,298)

A continued application of currently approved rates would provide annual depreciation expense of $45,473,702 compared with an annual expense of $43,499,404 using the rates recommended in the study. The resulting change in depreciation rates produces an annualized 2009 expense reduction of $1,974,298.

The scope of our investigation included:

- Collection of plant and net salvage data;
- Reconciliation of data to the official records of the Company;
- Site visits and discussions with NEC operations and plant accounting personnel;
- Statistical studies of historical retirement activity;

- Estimation of projection lives and retirement dispersion patterns;
- Analysis of gross salvage and cost of removal;
- Analysis and redistribution of recorded depreciation reserves; and
- Development of recommended accrual rates for each rate category.

The results of our investigation are presented in the enclosed report in five sections. The Executive Summary provides an overview of the review and a discussion of the principal findings. The Company Profile provides background information about NEC that is foundational to the study. The Study Procedure section describes the steps involved in conducting a comprehensive depreciation study and the specific procedures used in this engagement. The Statements provide a comparative summary of current and proposed depreciation parameters, rates and accruals. The report concludes with the Analysis section containing an example of supporting schedules prepared for each plant account.

We wish to express our appreciation for this opportunity to be of service to National Grid and for the assistance provided to us. We would be pleased to discuss the enclosed report with you or others at your convenience.

Respectfully submitted,
FOSTER ASSOCIATES, INC.
by

Ronald E. White, Ph.D.
Chairman

REW:ml

CONTENTS

EXECUTIVE SUMMARY

INTRODUCTION

This report presents findings and recommendations developed in a 2009 depreciation study conducted by Foster Associates, Inc. (Foster Associates) for electric plant owned and operated by The Narragansett Electric Company (NEC), distribution subsidiaries of National Grid. Work on the study commenced in February 2009 and progressed through mid–April, at which time the project was completed.

Foster Associates is a public utility economic consulting firm headquartered in Bethesda, Maryland offering economic research and consulting services on issues and problems arising from governmental regulation of business. Areas of specialization supported by the firm's Fort Myers, Florida office include property life forecasting, technological forecasting, depreciation estimation, and valuation of industrial property.

Foster Associates has undertaken numerous depreciation engagements for both public and privately owned business entities including detailed statistical life studies, analyses of required net salvage rates, and the selection of depreciation systems that will most nearly achieve the goals of depreciation accounting under the constraints of either government regulation or competitive market pricing. Foster Associates is widely recognized for industry leadership in the development of depreciation systems, life analysis techniques and computer software for conducting depreciation and valuation studies.

This is the second comprehensive depreciation study undertaken by NEC in recent years. Current depreciation rates were adopted pursuant to a Settlement Agreement in Docket No. 2290 (Agreement dated May 9, 1996) based on year–end 1994 plant and reserve balances. A net salvage study conducted in 1994 was initially filed in Docket No. 2290 with a request to commence accruing for net salvage pending completion of a full depreciation study. A completed study was subsequently filed in Docket No. 2290 and adjusted to derive settled depreciation rates. The Settlement Agreement provided: a) adoption of service life and net salvage parameters requested for transmission plant; b) retention of prior service lives for distribution plant; c) a 40–year service life for general plant Account 390.00 (Structures and Improvements); d) a 20–year amortization period for general plant accounts; and e) a –10 percent net salvage ratio for distribution plant.

The principal findings and recommendations of the 2009 Depreciation Rate Study are summarized in the Section IV of this report. Statement A provides a comparative summary of current and proposed annual depreciation rates for each rate category. Statement B provides a comparison of current and proposed annual depreciation accruals. Statement C provides a comparison of computed, recorded and redistributed depreciation reserves for each rate category. Statement D provides a summary of the components used to obtain weighted–average net salvage rates. Statement E provides an analysis of future net salvage rates for distribution plant accounts. Statement F provides a comparative summary of current and proposed parameters including projection life, projection curve and future net salvage rates. Statement F also contains current and proposed statistics including average service life, average remaining life, and average net salvage rates.

Scope of Study

The principal activities undertaken in the course of the current study included:

- Collection of plant and net salvage data;
- Reconciliation of data to the official records of the Company;
- Site visits and discussions with NEC operations and plant accounting personnel;
- Statistical studies of historical retirement activity;
- Estimation of projection lives and retirement dispersion patterns;
- Analysis of gross salvage and cost of removal;
- Analysis and redistribution of recorded depreciation reserves; and
- Development of recommended accrual rates for each rate category.

Depreciation System

A depreciation rate is formed by combining the elements of a depreciation system. A depreciation system is composed of a method, a procedure and a technique. A depreciation method (*e.g.*, straight–line) describes the component of the system that determines the acceleration or deceleration of depreciation accruals in relation to either time or use. A depreciation procedure (*e.g.*, vintage group) identifies the level of grouping or sub–grouping of assets within a plant category. The level of grouping specifies the weighting used to obtain composite life statistics for an account. A depreciation technique (*e.g.*, remaining–life) describes the life statistic used in the system.

With the exception of certain general plant categories for which amortization accounting has been approved, depreciation rates currently used by NEC were developed from a system composed of the straight–line method, vintage group procedure, remaining–life technique. Amortization accounting is used for general plant categories in which the unit cost of plant items is small in relation to the number of units classified in an account or the disposition of property units is difficult to identify. Plant is retired (*i.e.*, credited to plant and charged to the reserve) as each vintage achieves an age equal to the amortization period.

The matching and expense recognition principles of accounting provide that the cost of an asset (or group of assets) should be allocated to operations over an estimate of the economic life of the asset in proportion to the consumption of service potential. It is the opinion of Foster Associates that the objectives of depreciation accounting are being achieved through the use of the vintage group procedure, which distinguishes service lives among vintages, and the remaining–life technique, which provides cost apportionment over the estimated weighted average remaining life of a rate category. Although the emergence of economic factors such as competition and incentive forms of regulation may eventually encourage abandonment of the straight–line method, no attempt was made in the current study to address these concerns.

PROPOSED DEPRECIATION RATES

Table 1 below provides a summary of the changes in annual rates and accruals resulting from an application of the parameters and depreciation rates recommended in the 2009 study.

	Accrual Rate			2009 Annualized Accrual		
Function	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Transmission	2.29%	2.20%	-0.09%	$ 5,232,396	$ 5,038,030	$ (194,366)
Distribution	3.53%	3.35%	-0.18%	37,932,216	36,085,736	(1,846,480)
General Plant	4.07%	4.19%	0.12%	2,309,090	2,375,638	66,548
Total	3.34%	3.20%	-0.14%	$ 45,473,702	$ 43,499,404	$ (1,974,298)

Table 1. Current and Proposed Rates and Accruals

Foster Associates is recommending primary account depreciation rates equivalent to a composite rate of 3.20 percent. Depreciation expense is currently accrued at rates that composite to 3.34 percent. The recommended change in the composite depreciation rate is, therefore, a reduction of 0.14 percentage points.

A continued application of current rates would provide annualized depreciation expense of $45,473,702 compared with an annualized expense of $43,499,404 using the rates developed in this study. The proposed 2009 expense reduction is $1,974,298. The computed change in annualized accruals includes a reduction of $799,031 attributable to an amortization of a $23,507,827 reserve imbalance. The remaining portion of the change is attributable to adjustments in service life and net salvage statistics recommended in the 2009 study.

Of the 34 plant accounts included in the 2009 study, Foster Associates is recommending rate reductions for 22 accounts and rate increases for 12 accounts.

COMPANY PROFILE

GENERAL

The Narragansett Electric Company is a wholly–owned subsidiary of National Grid operating in Rhode Island. The Company was incorporated under the laws of the state of Rhode Island in 1926, as United Electric Power Company the name of the Company was subsequently changed to The Narragansett Electric Company in April of 1927. Narragansett was acquired by National Grid from New England Electric Systems in 1998.

The Narragansett Electric Company is a retail distribution company providing electric services to approximately 471,000 customers. The properties of the Company include an integrated system of transmission and distribution lines, interconnected with transmission and other facilities of New England Power Company (NEP), an affiliate. At December 31, 2008, Narragansett Electric owned 113 line transformers, and 416 circuit miles of transmission lines. The Company buys its electric energy requirements from NEP under contract. The Company participates through NEP in the New England Power Pool, which provides for the coordination of the planning and operation of the generation and transmission facilities in New England, and the region-wide central dispatch of generation.

SERVICE AREA

Electric service is provided to approximately 471,000 customers in 38 cities and towns. The Company's service area covers approximately 99 percent of Rhode Island.

CUSTOMER BASE

During 2008, nearly 45.4 percent of Narragansett Electric's revenue from the sale of electricity was derived from residential customers, 44.1 percent from commercial customers, 10.4 percent from industrial customers and 0.1 percent from others. The 20 largest customers of Narragansett accounted for approximately 0.0975 percent of its electric revenue.

STUDY PROCEDURE

INTRODUCTION

The purpose of a depreciation study is to analyze the mortality characteristics, net salvage rates and adequacy of depreciation accruals and recorded depreciation reserves for each rate category. This study provides the foundation and documentation for recommended changes in the depreciation rates used by NEC for transmission, distribution and general plant categories. The proposed rates are subject to approval by the Rhode Island Public Utilities Commission (PUC).

SCOPE

The steps involved in conducting a depreciation study can be grouped into five major tasks:

- Data Collection;
- Life Analysis and Estimation;
- Net Salvage Analysis;
- Depreciation Reserve Analysis; and
- Development of Accrual Rates.

The scope of the NEC 2009 study included a consideration of each of these tasks as described below.

DATA COLLECTION

The minimum database required to conduct a statistical life study consists of a history of vintage year additions and unaged activity–year retirements, transfers and adjustments. These data must be appropriately adjusted for transfers, sales and other plant activity that would otherwise bias the measured service life of normal retirements. The age distribution of surviving plant for unaged data can be estimated by distributing plant in service at the beginning of the study year to prior vintages in proportion to the theoretical amount surviving from a projection or survivor curve identified in the life study. The statistical methods of life analysis used to examine unaged plant data are known as *semi–actuarial techniques*.

A far more extensive database is required to apply statistical methods of life analysis known as *actuarial techniques*. Plant data used in an actuarial life study most often include age distributions of surviving plant at the beginning of a study year and the vintage year, activity year, and dollar amounts associated with normal retirements, reimbursed retirements, sales, abnormal retirements, transfers, corrections, and extraordinary adjustments over a series of prior activity years. An actuarial database may include age distributions of surviving plant at the beginning of the earliest activity year, rather than at the beginning of the study year. Plant additions, however, must be included in a database containing an opening age distribution to derive aged survivors at the beginning of the study year. All activity year transactions with vintage year identification are coded and stored in a database. These data are processed by a computer program and transaction summary reports are created in a format reconcilable to official plant records. The availability of such detailed information is dependent upon an accounting system that supports aged property records. The Continuing Property Record (CPR) system used by NEC provides aged transactions for all plant accounts.

The database used in conducting the 2009 study was assembled by appending 1995–2008 plant and reserve activity to the data base used in conducting the 1995 study. Detailed accounting transactions were extracted from the CPR system and assigned transaction codes which describe the nature of the accounting activity. Transaction codes for plant additions, for example, were used to distinguish normal additions from acquisitions, purchases, reimbursements and adjustments. Similar transaction codes were used to distinguish normal retirements from sales, reimbursements, abnormal retirements and adjustments. Transaction codes were also assigned to transfers, capital leases, gross salvage, cost of removal and other accounting activity considered in a depreciation study.

Prior to 1993, NEC estimated the ageing of plant activity for distribution mass plant accounts (Accounts 364.00 through 373.00) using an estimated projection life and curve for each account. Although theoretically sound for accounts in which population parameters are known, in practice this method is somewhat circular. The recorded plant activity is dependent upon the estimated parameters which are themselves developed from the plant activity they generate.

Foster Associates was engaged by NEC in 1993 to develop age distributions for Accounts 364.00 through 373.00 that would be used to initiate a first–in, first–out (FIFO) ageing process. The new age distributions at December 31, 1992 were used to populate the Company's CPR system in September 1993. Minor adjustments were recorded for January – September 1993 activity. The data base used in the current study for these accounts contains opening age distributions at December 31, 1992, and FIFO plant activity for 1993 through 2008. Plant installed prior to 1966 is classified in a 1966 vintage.

The data base used in the 1995 study for all other transmission, distribution, and general plant Accounts 390.00 (Structures and Improvements) and 397.00 (Communication Equipment) was constructed from the Company's CPR system by Company personnel. These plant records provided plant activity over the period 1969 through 1994 and age distributions of surviving plant at December 31, 1994. Age distributions of plant exposed to retirement at the beginning of each activity year were obtained by adding (or subtracting) transaction amounts to the coded age distributions of surviving plant at the end of 1994. Coded age distributions of surviving plant at the end of 1994 were then removed from the data base. This conversion of the data base from a reverse construction of the historical arrangement to a forward construction was made to facilitate appending post–1994 transactions to the data without removing or adjusting prior coded transactions.

The accuracy of the assembled data base for all accounts—except the FIFO mass accounts—was verified over the period 1969–1994 in the 1995 study by comparing the unadjusted plant history schedules derived in the study with the Company's ledger reports. The mass accounts were reconciled for post–1993 activity reflecting the FIFO ageing process.

The accuracy and completeness of the database used in conducting the 2009 study was confirmed by Foster Associates for activity years 1995–2008 by comparing additions, retirements, transfers, adjustments and ending plant balance to the regulated investments reported by NEC in FERC Form 1 electric plant in service reports. Age distributions of surviving plant at December 31, 2008 were reconciled to the CPR.

LIFE ANALYSIS AND ESTIMATION

Life analysis and life estimation are terms used to describe a two–step procedure for estimating the mortality characteristics of a plant category. The first step (*i.e.*, life analysis) is largely mechanical and primarily concerned with history. Statistical techniques are used in this step to obtain a mathematical description of the forces of retirement acting upon a plant category and an estimate of the *projection life* of the account. The mathematical expressions used to describe these life characteristics are known as *survival functions* or *survivor curves*.

The second step (*i.e.*, life estimation) is concerned with predicting the expected remaining life of property units still exposed to forces of retirement. It is a process of blending the results of a life analysis with informed judgment (including expectations about the future) to obtain an appropriate projection life and curve descriptive of the parent population from which a plant account is viewed as a random sample. The amount of weight given to a life analysis will depend upon the extent to which past retirement experience is considered descriptive of the future.

The analytical methods used in a life analysis are broadly classified as actuarial and semi–actuarial techniques. Actuarial techniques can be applied to plant accounting records that reveal the age of a plant asset at the time of its retirement from service. Stated differently, each property unit must be identifiable by date of installation and age at retirement. Semi–actuarial techniques can be used to derive service life and dispersion estimates when age identification of retirements is not maintained or readily available. Age identification of retirements was available for all plant accounts included in the 2009 NEC depreciation study.

An actuarial life analysis program designed and developed by Foster Associates was used in this study. The first step in an actuarial analysis involves a systematic treatment of the available data for the purpose of constructing an observed life table. A complete life table contains the life history of a group of property units installed during the same accounting period and various probability relationships derived from the data. A life table is arranged by age–intervals (usually defined as one year) and shows the number of units (or dollars) entering and leaving each age–interval and probability relationships associated with this activity. A life table minimally shows the age of each survivor and the age of each retirement from a group of units installed in a given accounting year.

A life table can be constructed in any one of at least five methods. The annual–rate or retirement–rate method was used in this study. The mechanics of the annual–rate method require the calculation of a series of ratios obtained by dividing the number of units (or dollars) surviving at the beginning of an age interval into the number of units (or dollars) retired during the same interval. This ratio—called a “retirement ratio” is an estimator of the hazard rate or conditional probability of retirement during an age interval. The cumulative proportion surviving is obtained by multiplying the retirement ratio for each age interval by the proportion of the original group surviving at the beginning of that age interval and subtracting this product from the proportion surviving at the beginning of the same interval. The annual–rate method is applied to multiple groups or vintages by combining the retirements and/or survivors of like ages for each vintage included in the analysis.

The second step in an actuarial analysis involves graduating or smoothing the observed life table and fitting the smoothed series to a family of survival functions. The functions used in this study are the Iowa–type curves which are mathematically described by the Pearson frequency curve family. The observed life table was smoothed by a weighted least–squares procedure in which first, second and third degree orthogonal polynomials were fitted to the observed retirement ratios. The resulting function can be expressed as a survivorship function which is numerically integrated to obtain an estimate of the projection life. The smoothed survivorship function is then fitted by a weighted least–squares procedure to the Iowa–curve family to obtain a mathematical description or classification of the dispersion characteristics of the data.

The set of computer programs used in this analysis provides multiple rolling–band, shrinking–band and progressive–band analyses of an account. Observation bands are defined in terms of a "retirement era" that restricts the analysis to the retirement activity of all vintages represented by survivors at the beginning of a selected era. In a rolling–band analysis, a year of retirement experience is added to each successive retirement band and the earliest year from the preceding band is dropped. A shrinking–band analysis begins with the total retirement experience available and the earliest year from the preceding band is dropped for each successive band. A progressive–band analysis adds a year of retirement activity to a previous band without dropping earlier years from the analysis. Rolling, shrinking and progressive band analyses are used to detect the emergence of trends in the behavior of the dispersion and projection life.

Options available in the Foster Associates actuarial life–analysis program include the width and location of both placement and observation bands; the interval of years included in a selected band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated. The program also provides both tabular and graphics output as an aid in the analysis.

While actuarial and semi–actuarial statistical methods are well suited to an analysis of plant categories containing a large number of homogeneous units (*e.g.*, meters or services), a different application of survivor curves is appropriate for plant categories composed of major items of plant that will most likely be retired as a single unit. Plant retirements from an integrated system prior to the retirement of the entire facility are viewed as interim retirements that will be replaced in order to maintain the integrity of the system. Plant facilities may also be added to an existing system (*i.e.*, interim additions) to expand or enhance its productive capacity without extending the service life of the existing system. A proper depreciation rate can be developed for an integrated system using a life–span method. All plant accounts were treated as full mortality categories in the NEC study.

NET SALVAGE ANALYSIS

Depreciation rates designed to achieve the goals and objectives of depreciation accounting will include a parameter for future net salvage and a variable for average net salvage reflecting both realized and future net salvage rates.

Estimates of net salvage rates applicable to future retirements are most often derived from an analysis of gross salvage and cost of removal realized in the past. An analysis of past experience (including an examination of trends over time) provides an initial basis for estimating future salvage and cost of removal. However, consideration should also be given to events that may cause deviations from net salvage realized in the past. Among the factors that should be considered are the age of plant retirements; the portion of retirements likely to be reused; changes in the method of removing plant; the type of plant to be retired in the future; inflation expectations; the shape of the projection life curve; and economic conditions that may warrant greater or lesser weight to be given to net salvage rates observed in the past.

Average net salvage rates for an account or plant function are derived from a direct dollar weighting of a) historical retirements with historical (or realized) net salvage rates and b) future retirements *(i.e.*, surviving plant) with estimated future net salvage rates. Average net salvage rates will change, therefore, as additional years of retirement and net salvage activity become available and as subsequent plant additions modify the weighting of future net salvage estimates. The computation of estimated average net salvage rates is shown in Statement D.

Special consideration should also be given to the treatment of insurance proceeds and other forms of third–party reimbursements credited to the depreciation reserve. A properly conducted net salvage study will exclude such activity from the estimate of future parameters and include the activity in the computation of realized and average net salvage rates. Third–party reimbursements are not distinguishable from salvage proceeds in NEC reserve records.

A five–year average analysis of the ratio of realized salvage and cost of removal to associated retirements was used in the 2009 study for all depreciable categories to: a) estimate realized net salvage rates; b) detect the emergence of historical trends; and c) establish a basis for estimating future net salvage rates. The banding analysis produced inconclusive indications of future net salvage ratios for reasons outlined below.

Prior to the 1995 study, depreciation rates used by NEC did not include a net salvage component; a net salvage rate of zero percent was implied for all plant accounts. While the 1995 study included a consideration of net salvage, accrual rates and reserves were developed at the function level for net salvage and by primary account for investment accruals. Upon implementation, NEC combined the function net salvage rates with in the investment rate for each primary account and continued to record depreciation accruals and realized net savage in function level reserves.

In 2004 NEC migrated to a plant accounting system supported by Power Plant. Function reserves were disaggregated in the conversion process to initialize reserves by primary account. Accordingly, the earliest activity year in which realized net salvage is identifiable by primary account is 2004. This limited history (combined with significant variability in realized net salvage as a percent of retirements) necessitated an examination of how net salvage is charged to work orders and a back–casting of current practices to prior activity years.

Net salvage is generally allocated to retirement work orders by applying appropriate ratios to associated capital additions. Statement E provides a computation of the composite ratio applied to primary distribution account additions over the period 2004–2008. The resulting ratios were applied to the sum of all additions over the period 1969–2008 for actual aged accounts and over the period

1993–2008 for FIFO aged accounts. The implied net salvage derived from this computation was expressed as a ratio to the sum of retirements recorded over the corresponding period of additions to obtain an estimate of future net salvage rates. A composite future net salvage rate of –30 percent was selected as a placeholder for all distribution accounts pending the realization of additional activity years from which net salvage rates among primary accounts may be distinguished.[1]

DEPRECIATION RESERVE ANALYSIS

The purpose of a depreciation reserve analysis is to compare the current level of recorded reserves with the level required to achieve the goals or objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized as predicted. The difference between a required (or theoretical) depreciation reserve and a recorded reserve provides a measurement of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is not taken to eliminate the reserve imbalance.

Unlike a recorded reserve which represents the net amount of depreciation expense charged to previous periods of operations, a theoretical reserve is a measure of the implied reserve requirement at the beginning of a study year if the timing of future retirements and net salvage is in exact conformance with a survivor curve chosen to predict the probable life of property still exposed to the forces of retirement. Stated differently, a theoretical depreciation reserve is the difference between the recorded cost of plant presently in service and the sum of depreciation expense and net salvage that will be charged in the future if retirements are distributed over time according to a specified retirement frequency distribution.

The survivor curve used in the calculation of a theoretical depreciation reserve is intended to describe forces of retirement that will be operative in the future. However, retirements caused by forces such as accidents, physical deterioration and changing technology seldom, if ever, remain stable over time. It is unlikely, therefore, that a probability or retirement frequency distribution can be identified that will accurately describe the age of plant retirements over the complete life cycle of multiple vintages. It is for this reason that depreciation rates should be reviewed periodically and adjusted for observed or expected changes in the parameters chosen to describe the underlying forces of mortality.

Although reserve records are commonly maintained by various account classifications, the total utility reserve in relation to the sum of account computed reserves is the most important indicator of the adequacy (or inadequacy) of recorded reserves. If statistical life studies have not been conducted or retirement dispersion

[1] A similar analysis of transmission accounts yielded unrealistic results as a consequence of insufficient data. The current approved future net salvage of –20 percent was retained for all transmission accounts.

has been overlooked in setting depreciation rates, it is likely that some accounts will be over–depreciated and other accounts will be under–depreciated relative to a calculated theoretical reserve. Differences between a theoretical reserve and a recorded reserve also will arise as a normal occurrence when service lives, dispersion patterns and net salvage estimates are adjusted in the course of depreciation reviews. It is appropriate, therefore, and consistent with group depreciation theory to periodically redistribute or rebalance recorded reserves among the various primary accounts based upon the most recent estimates of retirement dispersion and net salvage rates.

A redistribution of recorded reserves is considered appropriate for NEC at this time. Offsetting reserve imbalances attributable to both the passage of time and parameter adjustments recommended in the current study should be realigned among primary accounts to reduce offsetting imbalances and increase depreciation rate stability. Recorded reserves should also be realigned to establish reserves for subaccounts created subsequent to the adoption of current depreciation rates.

Recorded reserves for transmission and distribution plant accounts were rebalanced by multiplying the calculated reserve for each primary account within a function by the ratio of the function total recorded reserves to the function total calculated reserve. The sum of the redistributed reserves within a function is, therefore, equal to the function total recorded depreciation reserve before the redistribution. Reserves for general amortizable categories were adjusted by replacing recorded reserves with current measured theoretical reserves and distributing any reserve imbalances to depreciable categories within the general plant function.

Statement C provides a comparison of recorded, computed and redistributed reserves at December 31, 2008. The recorded reserve was $552,926,186 or 40.6 percent of the depreciable plant investment. The corresponding computed reserve is $529,418,359 or 38.9 percent of the depreciable plant investment. A proportionate amount of the measured reserve imbalance of $23,507,827 will be amortized over the composite weighted–average remaining life of each rate category using the remaining life depreciation rates proposed in this study.

Development of Accrual Rates

The goal or objective of depreciation accounting is cost allocation over the economic life of an asset in proportion to the consumption of service potential. Ideally, the cost of an asset—which represents the cost of obtaining a bundle of service units—should be allocated to future periods of operation in proportion to the amount of service potential expended during an accounting interval. The service potential of an asset is the present value of future net revenue (*i.e.*, revenue less expenses exclusive of depreciation and other non–cash expenses) or cash inflows attributable to the use of that asset alone.

Cost allocation in proportion to the consumption of service potential is often approximated by the use of depreciation methods employing time rather than net revenue as the apportionment base. Examples of time–based methods include sinking–fund, straight–line, declining balance, and sum–of–the–years' digits. The advantage of a time–based method is that it does not require an estimate of the remaining amount of service potential an asset will provide or the amount of potential actually consumed during an accounting interval. Using a time–based allocation method, however, does not change the goal of depreciation accounting. If it is predictable that the net revenue pattern of an asset will either decrease or increase over time, then an accelerated or decelerated time–based method should be used to approximate the rate at which service potential is actually consumed.

The time period over which the cost of an asset will be allocated to operations is determined by the combination of a procedure and a technique. A depreciation procedure describes the level of grouping or sub–grouping of assets within a plant category. The broad group, vintage group, equal–life group, and item (or unit) are a few of the more widely used procedures. A depreciation technique describes the life statistic used in a depreciation system. Whole–life and remaining–life (or expectancy) are the most common techniques.

Depreciation rates recommended in the 2009 study were developed using a system composed of the straight–line method, vintage group procedure, remaining–life technique. This formulation of the accrual rate is equivalent to a straight–line method, vintage group procedure, whole–life technique with amortization of reserve imbalances over the estimated composite remaining life of each rate category. It is the opinion of Foster Associates that this currently approved system will remain appropriate for NEC, provided depreciation studies are conducted periodically and parameters are routinely adjusted to reflect changing operating conditions.

It is also the opinion of Foster Associates that amortization accounting is consistent with the goals and objectives of depreciation accounting and remains appropriate for the approved amortization categories. The treatment of amortization accounts in the current study was designed to produce 2009 annualized accruals equivalent to applying a rate equal to the reciprocal of an amortization period to plant balances after retirements have been recorded. Accrual rates contained in Statement A have been applied to plant balances containing vintages that will be retired in 2009. Accrual rates equal to the reciprocal of the amortization period will be applied to these categories after plant balances have been reduced by all vintages that have achieved an age equal to the amortization period.

STATEMENTS

INTRODUCTION

This section provides a comparative summary of depreciation rates, annual depreciation accruals, recorded and computed depreciation reserves, and current and proposed service life and net salvage parameters recommended for NEC plant and equipment categories. The content of these statements is briefly described below.

- Statement A provides a comparative summary of current and proposed annual depreciation rates using the vintage group procedure, remaining–life technique.
- Statement B provides a comparison of current and proposed annualized 2009 depreciation accruals derived from the depreciation rates contained in Statement A.
- Statement C provides a comparison of recorded, computed and redistributed reserves for each rate category at December 31, 2008.
- Statement D provides a summary of the components used to obtain weighted average net salvage rates.
- Statement E provides an analysis of future net salvage rates for distribution plant accounts.
- Statement F provides a comparative summary of current and proposed parameters and statistics including projection life, projection curve, average service life, average remaining life, and average and future net salvage rates.

Current depreciation accruals shown on Statement B are the product of the plant investment (Column B) and current depreciation rates shown on Statement A. These are the effective rates used by NEC for the mix of investments recorded at December 31, 2008. Similarly, proposed depreciation accruals shown on Statements B are the product of the plant investment and proposed depreciation rates shown on Statement A. Proposed remaining life accrual rates (Statement A) are given by:

$$\text{Accrual Rate} = \frac{1.0 - \text{Reserve Ratio} - \text{Future Net Salvage Rate}}{\text{Remaining Life}}.$$

This formulation of a remaining–life accrual rate is equivalent to

$$\text{Accrual Rate} = \frac{1.0 - \text{Average Net Salvage}}{\text{Average Life}} + \frac{\text{Computed Reserve} - \text{Recorded Reserve}}{\text{Remaining Life}}$$

where Average Net Salvage, Computed Reserve and Recorded Reserve are expressed in percent.

THE NARRAGANSETT ELECTRIC COMPANY Statement A

Component Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

	Current			Proposed		
Account Description	Rem. Life	Future Salvage	Accrual Rate	Investment	Net Salvage	Total Rate
A	B	C	D	E	H	I=G+H
TRANSMISSION PLANT						
352.00 Structures and Improvements	21.84	-20.0%	1.65%	1.16%	0.25%	1.41%
353.00 Station Equipment	42.70	-20.0%	1.99%	1.57%	0.33%	1.90%
354.00 Towers and Fixtures	24.74	-20.0%	1.95%	-0.01%	0.01%	
355.00 Poles and Fixtures	30.60	-20.0%	2.40%	2.07%	0.53%	2.60%
356.00 Overhead Conductors and Devices	27.21	-20.0%	2.64%	1.83%	0.46%	2.29%
357.00 Underground Conduit	28.71	-20.0%	2.07%	1.79%	0.36%	2.15%
358.00 Underground Conductors and Devices	29.40	-20.0%	2.67%	2.00%	0.47%	2.47%
359.00 Roads and Trails	33.51	-20.0%	1.78%	0.96%	0.19%	1.15%
Total Transmission Plant			2.29%	1.79%	0.42%	2.20%
DISTRIBUTION PLANT						
361.00 Structures and Improvements	12.02	-10.0%	2.10%	1.47%	0.80%	2.27%
362.00 Station Equipment	25.16	-10.0%	2.97%	1.52%	0.45%	1.97%
364.00 Poles, Towers and Fixtures	19.53	-10.0%	4.17%	2.58%	1.00%	3.58%
365.00 Overhead Conductors and Devices	23.51	-10.0%	3.28%	2.44%	0.76%	3.20%
366.00 Underground Conduit	45.29	-10.0%	2.05%	1.66%	0.22%	1.88%
367.10 Underground Conductors and Devices	38.12	-10.0%	2.58%	2.64%	0.79%	3.43%
368.00 Line Transformers	15.23	-10.0%	4.44%			
368.10 Line Transformer Stations	15.23	-10.0%	4.44%	2.91%	0.87%	3.78%
368.20 Line Transformers - Bare Cost	15.23	-10.0%	4.44%	3.07%	0.94%	4.01%
368.30 Line Transformers - Install Cost	15.23	-10.0%	4.44%	3.10%	0.95%	4.05%
369.00 Services	11.78	-10.0%	4.26%			
369.10 Overhead Services	11.78	-10.0%	4.26%	2.45%	0.99%	3.44%
369.22 Underground Services	11.78	-10.0%	4.26%	2.43%	0.77%	3.20%
370.00 Meters	20.98	-10.0%	3.78%			
370.10 Meters - Bare Cost - Domestic	20.98	-10.0%	3.78%	4.04%	1.15%	5.19%
370.20 Meters - Install Cost - Domestic	20.98	-10.0%	3.78%	4.12%	1.17%	5.29%
370.30 Large Meters - Bare Cost	20.98	-10.0%	3.78%	4.06%	1.20%	5.26%
370.35 Large Meters - Install Cost	20.98	-10.0%	3.78%	3.77%	1.13%	4.90%
371.00 Installations on Customers' Premises	14.12	-10.0%	1.97%	2.86%	0.82%	3.68%
373.00 Street Lighting and Signal Systems	14.90	-10.0%	4.62%			
373.10 OH Street Lighting and Signal Systems	14.90	-10.0%	4.62%	4.34%	1.30%	5.64%
373.20 UG Street Lighting and Signal Systems	14.90	-10.0%	4.62%	4.33%	1.32%	5.65%
Total Distribution Plant			3.53%	2.55%	0.81%	3.35%
GENERAL PLANT						
Depreciable						
390.00 Structures and Improvements	32.61	-5.0%	2.82%	2.05%	0.19%	2.24%
397.10 Communication Equipment - Site Specific	11.14		5.00%	4.44%	0.22%	4.66%
Total Depreciable			3.40%	2.68%	0.20%	2.88%
Amortizable						
391.00 Office Furniture and Equipment	8.04		5.00%	← 15 Year Amortization →		1.37%
393.00 Stores Equipment	12.38		5.00%	← 15 Year Amortization →		2.67%
394.00 Tools, Shop and Garage Equipment	10.57		5.00%	← 15 Year Amortization →		4.97%
395.00 Laboratory Equipment	12.55		5.00%	← 15 Year Amortization →		4.26%
397.00 Communication Equipment	11.14		5.00%	← 15 Year Amortization →		6.67%
398.00 Miscellaneous Equipment	12.12		5.00%	← 15 Year Amortization →		2.87%
Total Amortizable			5.00%	5.99%		5.99%
Total General Plant			4.07%	4.08%	0.11%	4.19%
TOTAL ELECTRIC OPERATIONS			3.34%	2.48%	0.71%	3.20%

THE NARRAGANSETT ELECTRIC COMPANY

Statement B

Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/08 Plant Investment	Current	Proposed 2009 Annualized Accrual: Investment	Net Salvage	Total	Difference
A	B	C	D	E	F=D+E	I=F-C
TRANSMISSION PLANT						
352.00 Structures and Improvements	$ 3,457,911	$ 57,056	$ 40,112	$ 8,645	$ 48,757	$ (8,299)
353.00 Station Equipment	91,199,973	1,814,879	1,431,840	300,960	1,732,800	(82,079)
354.00 Towers and Fixtures	1,350,940	26,343	(135)	135		(26,343)
355.00 Poles and Fixtures	59,308,506	1,423,404	1,227,686	314,335	1,542,021	118,617
356.00 Overhead Conductors and Devices	40,753,341	1,075,888	745,786	187,465	933,251	(142,637)
357.00 Underground Conduit	4,830,086	99,983	86,459	17,388	103,847	3,864
358.00 Underground Conductors and Devices	27,194,077	726,082	543,882	127,812	671,694	(54,388)
359.00 Roads and Trails	492,182	8,761	4,725	935	5,660	(3,101)
Total Transmission Plant	$ 228,587,016	$ 5,232,396	$ 4,080,355	$ 957,675	$ 5,038,030	$ (194,366)
DISTRIBUTION PLANT						
361.00 Structures and Improvements	$ 6,272,627	$ 131,725	$ 92,208	$ 50,181	$ 142,389	$ 10,664
362.00 Station Equipment	155,660,801	4,623,126	2,366,044	700,474	3,066,518	(1,556,608)
364.00 Poles, Towers and Fixtures	172,167,037	7,179,365	4,441,910	1,721,670	6,163,580	(1,015,785)
365.00 Overhead Conductors and Devices	243,191,934	7,976,695	5,933,883	1,848,259	7,782,142	(194,553)
366.00 Underground Conduit	61,110,729	1,252,770	1,014,438	134,444	1,148,882	(103,888)
367.10 Underground Conductors and Devices	123,614,245	3,189,248	3,263,416	976,553	4,239,969	1,050,721
368.00 Line Transformers						
368.10 Line Transformer Stations	10,207,310	453,205	297,033	88,804	385,837	(67,368)
368.20 Line Transformers - Bare Cost	81,634,508	3,624,572	2,506,179	767,364	3,273,543	(351,029)
368.30 Line Transformers - Install Cost	55,254,569	2,453,303	1,712,892	524,918	2,237,810	(215,493)
369.00 Services						
369.10 Overhead Services	59,276,819	2,525,192	1,452,282	586,841	2,039,123	(486,069)
369.22 Underground Services	9,210,037	392,348	223,804	70,917	294,721	(97,627)
370.00 Meters						
370.10 Meters - Bare Cost - Domestic	22,541,337	852,063	910,670	259,225	1,169,895	317,832
370.20 Meters - Install Cost - Domestic	6,653,964	251,520	274,143	77,851	351,994	100,474
370.30 Large Meters - Bare Cost	10,154,885	383,855	412,288	121,859	534,147	150,292
370.35 Large Meters - Install Cost	9,094,453	343,770	342,861	102,767	445,628	101,858

THE NARRAGANSETT ELECTRIC COMPANY Statement B

Component Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/08 Plant Investment	Current	Proposed 2009 Annualized Accrual Investment	Net Salvage	Total	Difference
A	B	C	D	E	F=D+E	I=F-C
371.00 Installations on Customers' Premises	71,631	1,411	2,049	587	2,636	1,225
373.00 Street Lighting and Signal Systems						
373.10 OH Street Lighting and Signal Systems	34,618,321	1,599,366	1,502,435	450,038	1,952,473	353,107
373.20 UG Street Lighting and Signal Systems	15,122,980	698,682	654,825	199,623	854,448	155,766
Total Distribution Plant	$ 1,075,858,187	$ 37,932,216	$ 27,403,360	$ 8,682,375	$ 36,085,735	$ (1,846,481)
GENERAL PLANT						
Depreciable						
390.00 Structures and Improvements	$ 24,115,021	$ 680,044	$ 494,358	$ 45,819	$ 540,177	$ (139,867)
397.10 Communication Equipment - Site Specifi	8,653,462	432,673	384,214	19,038	403,252	(29,421)
Total Depreciable	$ 32,768,483	$ 1,112,717	$ 878,572	$ 64,857	$ 943,429	$ (169,288)
Amortizable						
391.00 Office Furniture and Equipment	$ 880,017	$ 44,001	$ 12,056	$ -	$ 12,056	$ (31,945)
393.00 Stores Equipment	465,721	23,286	12,435		12,435	(10,851)
394.00 Tools, Shop and Garage Equipment	2,744,432	137,222	136,398		136,398	(824)
395.00 Laboratory Equipment	1,952,521	97,626	83,177		83,177	(14,449)
397.00 Communication Equipment	17,759,267	887,963	1,184,543		1,184,543	296,580
398.00 Miscellaneous Equipment	125,496	6,275	3,602		3,602	(2,673)
Total Amortizable	$ 23,927,454	$ 1,196,373	$ 1,432,211	$ -	$ 1,432,211	$ 235,838
Total General Plant	$ 56,695,937	$ 2,309,090	$ 2,310,783	$ 64,857	$ 2,375,640	$ 66,550
TOTAL ELECTRIC OPERATIONS	$ 1,361,141,140	$ 45,473,702	$ 33,794,498	$ 9,704,907	$ 43,499,405	$ (1,974,297)

THE NARRAGANSETT ELECTRIC COMPANY
Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2008

Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
TRANSMISSION PLANT							
352.00 Structures and Improvements	$ 3,457,911	$ 2,723,750	78.77%	$ 2,526,824	73.07%	$ 3,040,197	87.92%
353.00 Station Equipment	91,199,973	23,338,157	25.59%	21,289,743	23.34%	25,615,160	28.09%
354.00 Towers and Fixtures	1,350,940	1,361,887	100.81%	1,346,835	99.70%	1,620,471	119.95%
355.00 Poles and Fixtures	59,308,506	17,002,216	28.67%	15,088,722	25.44%	18,154,283	30.61%
356.00 Overhead Conductors and Devices	40,753,341	17,907,988	43.94%	12,379,367	30.38%	14,894,470	36.55%
357.00 Underground Conduit	4,830,086	2,104,294	43.57%	1,931,787	39.99%	2,324,266	48.12%
358.00 Underground Conductors and Devices	27,194,077	13,126,844	48.27%	9,888,357	36.36%	11,897,365	43.75%
359.00 Roads and Trails	492,182	456,483	92.75%	395,131	80.28%	475,409	96.59%
Total Transmission Plant	$ 228,587,016	$ 78,021,620	34.13%	$ 64,846,767	28.37%	$ 78,021,620	34.13%
DISTRIBUTION PLANT							
361.00 Structures and Improvements	$ 6,272,627	$ 2,524,505	40.25%	$ 3,762,115	59.98%	$ 3,861,308	61.56%
362.00 Station Equipment	155,660,801	54,265,999	34.86%	37,413,976	24.04%	38,400,438	24.67%
364.00 Poles, Towers and Fixtures	172,167,037	70,693,489	41.06%	66,253,068	38.48%	67,999,905	39.50%
365.00 Overhead Conductors and Devices	243,191,934	104,912,861	43.14%	90,787,039	37.33%	93,180,742	38.32%
366.00 Underground Conduit	61,110,729	20,967,272	34.31%	29,705,216	48.61%	30,488,428	49.89%
367.10 Underground Conductors and Devices	123,614,245	22,508,953	18.21%	44,513,143	36.01%	45,686,783	36.96%
368.00 Line Transformers		80,911,248					
368.10 Line Transformer Stations	10,207,310			7,000,259	68.58%	7,184,829	70.39%
368.20 Line Transformers - Bare Cost	81,634,508			39,544,682	48.44%	40,587,322	49.72%
368.30 Line Transformers - Install Cost	55,254,569			24,600,628	44.52%	25,249,251	45.70%
369.00 Services		43,683,484					
369.10 Overhead Services	59,276,819			27,450,091	46.31%	28,173,844	47.53%
369.22 Underground Services	9,210,037			4,284,671	46.52%	4,397,642	47.75%
370.00 Meters		19,267,557					
370.10 Meters - Bare Cost - Domestic	22,541,337			13,403,576	59.46%	13,756,977	61.03%
370.20 Meters - Install Cost - Domestic	6,653,964			3,070,268	46.14%	3,151,219	47.36%
370.30 Large Meters - Bare Cost	10,154,885			5,740,575	56.53%	5,891,932	58.02%
370.35 Large Meters - Install Cost	9,094,453			7,201,534	79.19%	7,391,410	81.27%
371.00 Installations on Customers' Premises	71,631	895	1.25%	1,993	2.78%	2,046	2.86%
373.00 Street Lighting and Signal Systems		30,487,304					
373.10 OH Street Lighting and Signal Systems	34,618,321			24,319,200	70.25%	24,960,403	72.10%
373.20 UG Street Lighting and Signal Systems	15,122,980			9,605,821	63.52%	9,859,090	65.19%
Total Distribution Plant	$ 1,075,858,187	$ 450,223,567	41.85%	$ 438,657,854	40.77%	$ 450,223,567	41.85%

THE NARRAGANSETT ELECTRIC COMPANY
Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2008

Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
GENERAL PLANT							
Depreciable							
390.00 Structures and Improvements	$ 24,115,021	$ 7,817,016	32.42%	$ 6,773,476	28.09%	$ 6,046,544	25.07%
397.10 Communication Equipment - Site Specific	8,653,462			4,713,071	54.46%	4,207,263	48.62%
Total Depreciable	$ 32,768,483	$ 7,817,016	23.86%	$ 11,486,546	35.05%	$ 10,253,807	31.29%
Amortizable							
391.00 Office Furniture and Equipment	$ 880,017	$ 770,703	87.58%	$ 854,476	97.10%	$ 854,476	97.10%
393.00 Stores Equipment	465,721	344,869	74.05%	413,472	88.78%	413,472	88.78%
394.00 Tools, Shop and Garage Equipment	2,744,432	1,424,308	51.90%	1,988,664	72.46%	1,988,664	72.46%
395.00 Laboratory Equipment	1,952,521	1,093,384	56.00%	1,334,671	68.36%	1,334,671	68.36%
397.00 Communication Equipment	17,759,267	13,130,060	73.93%	9,719,849	54.73%	9,719,849	54.73%
398.00 Miscellaneous Equipment	125,496	100,659	80.21%	116,060	92.48%	116,060	92.48%
Total Amortizable	$ 23,927,454	$ 16,863,983	70.48%	$ 14,427,192	60.30%	$ 14,427,192	60.30%
Total General Plant	$ 56,695,937	$ 24,680,999	43.53%	$ 25,913,738	45.71%	$ 24,680,999	43.53%
TOTAL ELECTRIC OPERATIONS	$ 1,361,141,140	$ 552,926,186	40.62%	$ 529,418,359	38.90%	$ 552,926,186	40.62%

THE NARRAGANSETT ELECTRIC COMPANY
Average Net Salvage

Statement D

Account Description	Plant Investment Additions	Plant Investment Retirements	Plant Investment Survivors	Salvage Rate Realized	Salvage Rate Future	Net Salvage Realized	Net Salvage Future	Net Salvage Total	Average Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
TRANSMISSION PLANT									
352.00 Structures and Improvements	$ 3,523,417	$ 65,506	$ 3,457,911	-56.2%	-20.0%	$ (36,814)	$ (691,582)	$ (728,397)	-20.7%
353.00 Station Equipment	98,226,409	7,026,436	91,199,973	-33.7%	-20.0%	(2,367,909)	(18,239,995)	(20,607,904)	-21.0%
354.00 Towers and Fixtures	1,562,622	211,682	1,350,940	-30.7%	-20.0%	(64,986)	(270,188)	(335,174)	-21.4%
355.00 Poles and Fixtures	63,810,483	4,501,977	59,308,506	-78.4%	-20.0%	(3,529,550)	(11,861,701)	(15,391,251)	-24.1%
356.00 Overhead Conductors and Devices	43,322,186	2,568,845	40,753,341	-89.0%	-20.0%	(2,286,272)	(8,150,668)	(10,436,940)	-24.1%
357.00 Underground Conduit	4,848,046	17,960	4,830,086		-20.0%		(966,017)	(966,017)	-19.9%
358.00 Underground Conductors and Devices	28,006,510	812,433	27,194,077	-125.0%	-20.0%	(1,015,541)	(5,438,815)	(6,454,357)	-23.0%
359.00 Roads and Trails	496,442	4,260	492,182		-20.0%		(98,436)	(98,436)	-19.8%
Total Transmission Plant	$ 243,796,115	$ 15,209,099	$ 228,587,016	-61.2%	-20.0%	$ (9,301,073)	$ (45,717,403)	$ (55,018,476)	-22.6%
DISTRIBUTION PLANT									
361.00 Structures and Improvements	$ 6,716,256	$ 443,629	$ 6,272,627	-373.0%	-30.0%	$ (1,654,736)	$ (1,881,788)	$ (3,536,524)	-52.7%
362.00 Station Equipment	175,916,122	20,255,321	155,660,801	-24.5%	-30.0%	(4,962,554)	(46,698,240)	(51,660,794)	-29.4%
364.00 Poles, Towers and Fixtures	184,165,216	11,998,179	172,167,037	-155.4%	-30.0%	(18,645,170)	(51,650,111)	(70,295,281)	-38.2%
365.00 Overhead Conductors and Devices	272,231,001	29,039,067	243,191,934	-40.3%	-30.0%	(11,702,744)	(72,957,580)	(84,660,324)	-31.1%
366.00 Underground Conduit	62,715,080	1,604,351	61,110,729	588.4%	-30.0%	9,440,001	(18,333,219)	(8,893,217)	-14.2%
367.10 Underground Conductors and Devices	138,368,087	14,753,842	123,614,245	-26.5%	-30.0%	(3,909,768)	(37,084,274)	(40,994,042)	-29.6%
368.00 Line Transformers									
368.10 Line Transformer Stations	10,221,898	14,588	10,207,310	-46.5%	-30.0%	(6,783)	(3,062,193)	(3,068,976)	-30.0%
368.20 Line Transformers - Bare Cost	84,561,856	2,927,348	81,634,508	-46.5%	-30.0%	(1,361,217)	(24,490,352)	(25,851,569)	-30.6%
368.30 Line Transformers - Install Cost	57,277,400	2,022,831	55,254,569	-46.5%	-30.0%	(940,616)	(16,576,371)	(17,516,987)	-30.6%
369.00 Services									
369.10 Overhead Services	62,987,283	3,710,464	59,276,819	-196.3%	-30.0%	(7,283,641)	(17,783,046)	(25,066,687)	-39.8%
369.22 Underground Services	9,304,031	93,994	9,210,037	-196.3%	-30.0%	(184,510)	(2,763,011)	(2,947,521)	-31.7%
370.00 Meters									
370.10 Meters - Bare Cost - Domestic	26,737,655	4,196,318	22,541,337	-19.8%	-30.0%	(830,871)	(6,762,401)	(7,593,272)	-28.4%
370.20 Meters - Install Cost - Domestic	7,830,338	1,176,374	6,653,964	-19.8%	-30.0%	(232,922)	(1,996,189)	(2,229,111)	-28.5%
370.30 Large Meters - Bare Cost	10,492,996	338,111	10,154,885	-19.8%	-30.0%	(66,946)	(3,046,466)	(3,113,411)	-29.7%
370.35 Large Meters - Install Cost	9,119,539	25,086	9,094,453	-19.8%	-30.0%	(4,967)	(2,728,336)	(2,733,303)	-30.0%
371.00 Installations on Customers' Premises	74,697	3,066	71,631		-30.0%		(21,489)	(21,489)	-28.8%
373.00 Street Lighting and Signal Systems									
373.10 OH Street Lighting and Signal Systems	35,364,400	746,079	34,618,321	-36.6%	-30.0%	(273,065)	(10,385,496)	(10,658,561)	-30.1%
373.20 UG Street Lighting and Signal Systems	15,932,458	809,478	15,122,980	-36.6%	-30.0%	(296,269)	(4,536,894)	(4,833,163)	-30.3%
Total Distribution Plant	$ 1,170,016,313	$ 94,158,126	$ 1,075,858,187	-45.6%	-30.0%	$ (42,916,778)	$ (322,757,456)	$ (365,674,235)	-31.3%

THE NARRAGANSETT ELECTRIC COMPANY
Average Net Salvage

Statement D

Account Description	Plant Investment Additions	Plant Investment Retirements	Plant Investment Survivors	Salvage Rate Realized	Salvage Rate Future	Net Salvage Realized	Net Salvage Future	Net Salvage Total	Average Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
GENERAL PLANT									
Depreciable									
390.00 Structures and Improvements	$ 27,234,744	$ 3,119,723	$ 24,115,021	-53.3%	-5.0%	$ (1,662,812)	$ (1,205,751)	$ (2,868,563)	-10.5%
397.10 Communication Equipment - Site Specific	8,653,462		8,653,462		-5.0%		(432,673)	(432,673)	-5.0%
Total Depreciable	$ 35,888,206	$ 3,119,723	$ 32,768,483	-53.3%	-5.0%	$ (1,662,812)	$ (1,638,424)	$ (3,301,237)	-9.2%
Amortizable									
391.00 Office Furniture and Equipment	$ 2,052,286	$ 1,172,269	$ 880,017			$ -	$ -	$ -	
393.00 Stores Equipment	803,253	337,532	465,721						
394.00 Tools, Shop and Garage Equipment	4,591,330	1,846,898	2,744,432						
395.00 Laboratory Equipment	2,489,857	537,336	1,952,521						
397.00 Communication Equipment	18,553,893	794,626	17,759,267						
398.00 Miscellaneous Equipment	397,069	271,573	125,496						
Total Amortizable	$ 28,887,688	$ 4,960,234	$ 23,927,454			$ -	$ -	$ -	
Total General Plant	$ 64,775,894	$ 8,079,957	$ 56,695,937	-20.6%	-2.9%	$ (1,662,812)	$ (1,638,424)	$ (3,301,237)	-5.1%
TOTAL ELECTRIC OPERATIONS	$ 1,478,588,322	$117,447,182	$ 1,361,141,140	-45.9%	-27.2%	$ (53,880,664)	$ (370,113,283)	$ (423,993,947)	-28.7%

THE NARRAGANSETT ELECTRIC COMPANY
Future Net Salvage
Distribution Plant

Statement E

Account	2004 - 2008 Additions	Net Salvage	Pecent	All Additions	Net Salvage	All Retirements	Sf
A	B	C	D=C/B	E	F=D*E	G	H=F/G
36100	$ 1,828,579	$ 1,154,921	63.16%	$ 2,236,547	$ 1,412,592	$ 443,629	318.42%
36200	25,978,614	1,054,503	4.06%	126,198,742	5,122,556	20,255,321	25.29%
36400	35,149,028	4,576,729	13.02%	100,838,884	13,130,157	11,998,180	109.43%
36500	57,128,861	4,689,171	8.21%	144,351,727	11,848,475	29,039,067	40.80%
36600	9,142,992	(995,934)	-10.89%	34,122,522	(3,716,921)	1,604,350	-231.68%
36710	39,930,351	1,829,236	4.58%	81,439,433	3,730,795	14,753,841	25.29%
36800				42,908,519		23,247,701	
36810	(3,468,875)			(3,468,875)		14,587	
36820	24,690,774			24,690,774		2,927,348	
36830	16,497,144			16,497,144		2,022,831	
	37,719,042	2,308,697	6.12%	80,627,561	4,935,030	28,212,468	17.49%
36910	12,995,051			30,734,528		3,710,465	
36922	3,366,476			3,366,476		93,995	
	16,361,527	1,879,983	11.49%	34,101,004	3,918,296	3,804,459	102.99%
37000				19,749,558		15,175,049	
37010	4,972,707			4,972,707		4,196,317	
37020	2,849,386			2,849,386		1,176,374	
37030	1,545,020			1,545,020		338,111	
37035	596,875			596,875		25,087	
	9,963,988	1,137,702	11.42%	29,713,546	3,392,735	20,910,938	16.22%
37100	71,631			71,631		3,066	
37300				23,858,692		27,208,835	
37310	1,399,574			1,399,574		746,079	
37320	5,324,219			5,324,219		809,478	
	6,723,793	569,594	8.47%	30,582,485	2,590,739	28,764,392	9.01%
Total	$ 239,998,406	$ 18,204,602	7.59%	$ 664,284,082	$ 46,364,455	$ 159,789,711	29.02%

THE NARRAGANSETT ELECTRIC COMPANY
Current and Proposed Parameters
Vintage Group Procedure

Statement F

	Current Parameters						Proposed Parameters (at December 31, 2008)					
Account Description	P-Life/ AYFR	Curve Shape	Avg. Life	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
TRANSMISSION PLANT												
352.00 Structures and Improvements	50.00	R4	54.65	21.84	-19.5	-20.0	55.00	S4	58.49	22.74	-20.7	-20.0
353.00 Station Equipment	55.00	L0	57.59	42.70	-19.5	-20.0	60.00	L1	60.49	48.32	-21.0	-20.0
354.00 Towers and Fixtures	50.00	R4	50.16	24.74	-19.5	-20.0	50.00	R4	83.23	13.92	-21.4	-20.0
355.00 Poles and Fixtures	45.00	S2	44.77	30.60	-19.5	-20.0	45.00	S2	45.16	34.41	-24.1	-20.0
356.00 Overhead Conductors and Devices	40.00	S1.5	39.96	27.21	-19.5	-20.0	50.00	S1.5	50.43	36.42	-24.1	-20.0
357.00 Underground Conduit	50.00	R4	50.09	28.71	-19.5	-20.0	50.00	R4	50.10	33.43	-19.9	-20.0
358.00 Underground Conductors and Devices	40.00	L2	40.39	29.40	-19.5	-20.0	45.00	L2	45.31	30.81	-23.0	-20.0
359.00 Roads and Trails	60.00	R5	60.00	33.51	-19.5	-20.0	60.00	R5	61.35	20.34	-19.8	-20.0
Total Transmission Plant									51.84	38.77	-22.6	-20.0
DISTRIBUTION PLANT												
361.00 Structures and Improvements	50.00	R4	55.97	12.02	-11.4	-10.0	55.00	R4	65.77	30.16	-52.7	-30.0
362.00 Station Equipment	35.00	SC	38.33	25.16	-11.4	-10.0	65.00	L0.5	65.43	53.58	-29.4	-30.0
364.00 Poles, Towers and Fixtures	25.00	SC	26.23	19.53	-11.4	-10.0	38.00	S2	38.19	25.29	-38.2	-30.0
365.00 Overhead Conductors and Devices	35.00	L4	34.19	23.51	-11.4	-10.0	40.00	L1.5	40.56	28.67	-31.1	-30.0
366.00 Underground Conduit	60.00	S4	59.26	45.29	-11.4	-10.0	60.00	S4	59.73	42.57	-14.2	-30.0
367.10 Underground Conductors and Devices	45.00	L0	45.14	38.12	-11.4	-10.0	37.00	S0.5	37.45	27.16	-29.6	-30.0
368.00 Line Transformers	25.00	S2	24.44	15.23	-11.4	-10.0						
368.10 Line Transformer Stations	25.00	S2	24.44	15.23	-11.4	-10.0	31.00	S1	33.40	15.78	-30.0	-30.0
368.20 Line Transformers - Bare Cost	25.00	S2	24.44	15.23	-11.4	-10.0	31.00	S1	32.09	20.04	-30.6	-30.0
368.30 Line Transformers - Install Cost	25.00	S2	24.44	15.23	-11.4	-10.0	31.00	S1	31.78	20.80	-30.6	-30.0
369.00 Services	25.00	S4	25.42	11.78	-11.4	-10.0						
369.10 Overhead Services	25.00	S4	25.42	11.78	-11.4	-10.0	40.00	S4	40.09	24.00	-39.8	-30.0
369.22 Underground Services	25.00	S4	25.42	11.78	-11.4	-10.0	40.00	S4	40.53	25.69	-31.7	-30.0
370.00 Meters	30.00	R2.5	29.25	20.98	-11.4	-10.0						
370.10 Meters - Bare Cost - Domestic	30.00	R2.5	29.25	20.98	-11.4	-10.0	23.00	R2	24.21	13.30	-28.4	-30.0
370.20 Meters - Install Cost - Domestic	30.00	R2.5	29.25	20.98	-11.4	-10.0	23.00	R2	23.92	15.61	-28.5	-30.0
370.30 Large Meters - Bare Cost	30.00	R2.5	29.25	20.98	-11.4	-10.0	23.00	R2	24.15	13.68	-29.7	-30.0
370.35 Large Meters - Install Cost	30.00	R2.5	29.25	20.98	-11.4	-10.0	23.00	R2	25.43	9.94	-30.0	-30.0

THE NARRAGANSETT ELECTRIC COMPANY
Current and Proposed Parameters
Vintage Group Procedure

Statement F

	Current Parameters						Proposed Parameters (at December 31, 2008)					
Account Description	P-Life/ AYFR	Curve Shape	Avg. Life	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
371.00 Installations on Customers' Premises	35.00	L0	60.72	14.12	-11.4	-10.0	35.00	L0	35.00	34.57	-28.8	-30.0
373.00 Street Lighting and Signal Systems	25.00	R3	23.40	14.90	-11.4	-10.0						
373.10 OH Street Lighting and Signal Systems	25.00	R3	23.40	14.90	-11.4	-10.0	20.00	L2	22.34	10.26	-30.1	-30.0
373.20 UG Street Lighting and Signal Systems	25.00	R3	23.40	14.90	-11.4	-10.0	20.00	L2	22.50	11.48	-30.3	-30.0
Total Distribution Plant									38.69	26.34	-31.3	-30.0
GENERAL PLANT												
Depreciable												
390.00 Structures and Improvements	40.00	L0.5	41.91	32.61	-5.5	-5.0	50.00	L1	51.19	35.63	-10.5	-5.0
397.10 Communication Equipment - Site Specific	20.00	SQ	20.00	11.14			25.00	S3	25.12	12.09	-5.0	-5.0
Total Depreciable									40.18	25.69	-9.2	-5.0
Amortizable												
391.00 Office Furniture and Equipment	20.00	SQ	20.00	8.04			15.00	SQ	15.00	2.11		
393.00 Stores Equipment	20.00	SQ	20.00	12.38			15.00	SQ	15.00	4.20		
394.00 Tools, Shop and Garage Equipment	20.00	SQ	20.00	10.57			15.00	SQ	15.00	5.54		
395.00 Laboratory Equipment	20.00	SQ	20.00	12.55			15.00	SQ	15.00	7.43		
397.00 Communication Equipment	20.00	SQ	20.00	11.14			15.00	SQ	15.00	6.79		
398.00 Miscellaneous Equipment	20.00	SQ	20.00	12.12			15.00	SQ	15.00	2.62		
Total Amortizable									15.00	6.45		
Total General Plant									23.52	12.96	-5.1	-2.9
TOTAL ELECTRIC OPERATIONS									39.31	26.99	-28.7	-27.2

ANALYSIS

INTRODUCTION

This section provides an explanation of the supporting schedules developed in the NEC depreciation study to estimate appropriate projection curves, projection lives and net salvage statistics for each rate category. The form and content of the schedules developed for an account depend upon the method of analysis adopted for the category.

This section also includes an example of the supporting schedules developed for Account 367.10 – Underground Conductors and Devices. Documentation for all other plant accounts is contained in the study work papers. Supporting schedules developed in the NEC study include:

Schedule A – Generation Arrangement;

Schedule B – Age Distribution;

Schedule C – Plant History;

Schedule D – Actuarial Life Analysis;

Schedule E – Graphics Analysis; and

Schedule F – Historical Net Salvage Analysis.

The format and content of these schedules are briefly described below.

SCHEDULE A – GENERATION ARRANGEMENT

The purpose of this schedule is to obtain appropriate weighted–average life statistics for a rate category. A weighted–average remaining–life is the sum of Column H divided by the sum of Column I. A weighted average life is the sum of Column C divided by the sum of Column I.

It should be noted that the generation arrangement does not include parameters for net salvage. Computed Net Plant (Column H) and Accruals (Column I) must be adjusted for net salvage to obtain a correct measurement of theoretical reserves and annualized depreciation accruals.

The following table provides a description of each column in the generation arrangement.

Column	Title	Description
A	Vintage	Vintage or placement year of surviving plant.
B	Age	Age of surviving plant at beginning of study year.
C	Surviving Plant	Actual dollar amount of surviving plant.
D	Average Life	Estimated average life of each vintage. This statistic is the sum of the realized life and the unrealized life, which is the product of the remaining life (Column E) and the theoretical proportion surviving.
E	Remaining Life	Estimated remaining life of each vintage.
F	Net Plant Ratio	Theoretical net plant ratio of each vintage.
G	Allocation Factor	A pivotal ratio which determines the amortization period of the difference between the recorded and computed reserve.
H	Computed Net Plant	Plant in service less theoretical reserve for each vintage.
I	Accrual	Ratio of computed net plant (Column H) and remaining life (Column E).

Table 2. Generation Arrangement

SCHEDULE B – AGE DISTRIBUTION

This schedule provides the age distribution and realized life of surviving plant shown in Column C of the Generation Arrangement (Schedule A). The format of the schedule depends upon the availability of either aged or unaged data. Derived additions for vintage years older than the earliest activity year in an account for unaged data are obtained from the age distribution of surviving plant at the beginning of the earliest activity year. The amount surviving from these vintages is shown in Column D. The realized life (Column G) is derived from the dollar years of service provided by a vintage over the period of years the vintage has been in service. Plant additions for vintages older than the earliest activity year in an account are represented by the opening balances shown in Column D.

The computed proportion surviving (Column D) for unaged data is derived from a computed mortality analysis. The average service life displayed in the title block is the life statistic derived for the most recent activity year, given the derived age distribution at the start of the year and the specified retirement dispersion. The realized life (Column F) is obtained by finding the slope of an SC retirement dispersion, which connects the computed survivors of a vintage (Column E) to the recorded vintage addition (Column B). The realized life is the area bounded by the SC dispersion, the computed proportion surviving and the age of the vintage.

SCHEDULE C – PLANT HISTORY

An Unadjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the database in which all plant accounting transactions are identified by vintage and activity year. Activity year totals for unaged data are obtained from a transaction file without vintage identification. Information displayed in the unadjusted plant history is consistent with regulated investments reported internally by the Company.

An Adjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company with sales, transfers, and adjustments appropriately aged for depreciation study purposes. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the data base in which all plant accounting transactions are identified by vintage and activity year. Ageing of adjusting transactions is achieved using transaction codes that identify an adjusting year associated with the dollar amount of a transaction. Adjusting transactions processed in the adjusted plant history are not aged in the Company's records or in the unadjusted plant history.

SCHEDULE D – ACTUARIAL LIFE ANALYSIS

These schedules provide a summary of the dispersion and life indications obtained from an actuarial life analysis for a specified placement band. The observation band (Column A) is specified to produce a rolling–band, shrinking–band, or progressive–band analysis depending upon the movement of the end points of the band. The degree of censoring (or point of truncation) of the observed life table is shown in Column B for each observation band. The estimated average service life, best fitting Iowa dispersion, and a statistical measure of the goodness of fit are shown for each degree polynomial (First, Second, and Third) fitted to the estimated hazard rates. Options available in the analysis include the width and location of both the placement and observation bands; the interval of years included in a selected rolling, shrinking, or progressive band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated.

Estimated projection lives (Columns C, F, and I) are flagged with an asterisk if negative hazard rates are indicated by the fitted polynomial. All negative hazard rates are set equal to zero in the calculation of the graduated survivor curve. The Conformance Index (Columns E, H, and K) is the square root of the mean sum–

of–squared differences between the graduated survivor curve and the best fitting Iowa curve. A Conformance Index of zero would indicate a perfect fit.

SCHEDULE E – GRAPHICS ANALYSIS

This schedule provides a graphics plot of a) the observed proportion surviving for a selected placement and observation band; b) the statistically best fitting Iowa dispersion and derived average service life; and c) the projection curve and projection life selected to describe future forces of mortality.

The graphics analysis also provides a plot of the observed hazard rates and graduated hazard function for a selected placement and observation band. The estimator of the hazard rates and weighting used in fitting orthogonal polynomials to the observed data are displayed in the title block of the displayed graph.

SCHEDULE F – HISTORICAL NET SALVAGE ANALYSIS

This schedule provides a moving average analysis of the ratio of realized net salvage (Column I) to the associated retirements (Column B). The schedule also provides a moving average analysis of the components of net salvage related to retirements. The ratio of gross salvage to retirements is shown in Column D and the ratio of cost of removal to retirements is shown in Column G

NARRAGANSETT ELECTRIC COMPANY
Distribution Plant
Account: 367.10 Underground Conductors and Devices

Dispersion: 37 - S0.5
Procedure: Vintage Group

Generation Arrangement

Vintage	Age	December 31, 2008 Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
2008	0.5	8,113,794	37.00	36.51	0.9867	1.0000	8,005,732	219,291
2007	1.5	8,979,570	37.00	35.55	0.9607	1.0000	8,626,626	242,686
2006	2.5	8,760,000	36.99	34.61	0.9357	1.0000	8,197,011	236,806
2005	3.5	8,070,975	36.97	33.71	0.9118	1.0000	7,359,512	218,324
2004	4.5	2,745,603	36.92	32.83	0.8892	1.0000	2,441,291	74,367
2003	5.5	4,204,193	36.77	31.97	0.8694	1.0000	3,655,314	114,337
2002	6.5	3,503,628	36.94	31.13	0.8428	1.0000	2,952,892	94,842
2001	7.5	2,668,819	37.04	30.32	0.8186	1.0000	2,184,678	72,051
2000	8.5	3,627,742	36.96	29.53	0.7989	1.0000	2,898,247	98,149
1999	9.5	2,912,662	37.01	28.76	0.7771	1.0000	2,263,464	78,707
1998	10.5	5,275,036	37.04	28.01	0.7561	1.0000	3,988,588	142,417
1997	11.5	5,000,094	36.70	27.27	0.7432	1.0000	3,715,937	136,246
1996	12.5	3,729,359	36.64	26.56	0.7250	1.0000	2,703,720	101,797
1995	13.5	3,733,845	37.08	25.86	0.6976	1.0000	2,604,704	100,707
1994	14.5	4,718,116	36.57	25.19	0.6887	1.0000	3,249,174	129,010
1993	15.5	4,115,941	37.26	24.52	0.6581	1.0000	2,708,877	110,461
1992	16.5	5,030,538	37.62	23.88	0.6347	1.0000	3,193,073	133,727
1991	17.5	6,766,104	37.27	23.25	0.6238	1.0000	4,220,603	181,556
1990	18.5	2,883,568	37.75	22.63	0.5995	1.0000	1,728,556	76,381
1989	19.5	1,991,090	37.85	22.03	0.5820	1.0000	1,158,823	52,603
1988	20.5	2,889,573	37.96	21.44	0.5648	1.0000	1,632,045	76,116
1987	21.5	2,733,976	38.18	20.87	0.5466	1.0000	1,494,412	71,617
1986	22.5	1,351,980	38.23	20.30	0.5311	1.0000	717,986	35,360
1985	23.5	1,027,863	38.58	19.76	0.5120	1.0000	526,254	26,639
1984	24.5	1,385,549	38.76	19.22	0.4958	1.0000	686,998	35,750
1983	25.5	1,631,310	38.76	18.69	0.4822	1.0000	786,672	42,092
1982	26.5	906,928	38.98	18.17	0.4663	1.0000	422,863	23,268
1981	27.5	1,446,595	39.12	17.67	0.4516	1.0000	653,259	36,976
1980	28.5	1,565,289	39.23	17.17	0.4376	1.0000	685,047	39,896
1979	29.5	1,340,243	38.37	16.68	0.4348	1.0000	582,709	34,926
1978	30.5	755,805	39.99	16.21	0.4052	1.0000	306,264	18,898
1977	31.5	1,201,140	40.27	15.74	0.3908	1.0000	469,448	29,830
1976	32.5	1,374,407	40.25	15.28	0.3795	1.0000	521,595	34,143
1975	33.5	1,009,209	40.42	14.82	0.3668	1.0000	370,149	24,969
1974	34.5	808,228	39.97	14.38	0.3598	1.0000	290,794	20,223
1973	35.5	773,324	40.79	13.94	0.3418	1.0000	264,334	18,960

NARRAGANSETT ELECTRIC COMPANY
Distribution Plant
Account: 367.10 Underground Conductors and Devices

Dispersion: 37 - S0.5
Procedure: Vintage Group

Generation Arrangement

Vintage	Age (December 31, 2008)	Surviving Plant (December 31, 2008)	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1972	36.5	859,982	38.15	13.51	0.3541	1.0000	304,536	22,540
1971	37.5	531,254	39.65	13.09	0.3301	1.0000	175,366	13,399
1970	38.5	314,254	40.50	12.67	0.3128	1.0000	98,300	7,758
1969	39.5	259,554	41.31	12.26	0.2968	1.0000	77,024	6,283
1968	40.5	115,549	40.36	11.85	0.2937	1.0000	33,938	2,863
1967	41.5	90,641	42.07	11.45	0.2722	1.0000	24,676	2,154
1966	42.5	2,410,915	39.18	11.06	0.2823	1.0000	680,570	61,535
Total	13.1	$123,614,245	37.45	27.16	0.7253	1.0000	$89,662,066	$3,300,660

NARRAGANSETT ELECTRIC COMPANY
Distribution Plant
Account: 367.10 Underground Conductors and Devices

Age Distribution

Vintage	Age as of 12/31/2008	Derived Additions	1993 Opening Balance	Experience to 12/31/2008 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
2008	0.5	8,113,794		8,113,794	1.0000	0.5000
2007	1.5	8,980,538		8,979,570	0.9999	1.4999
2006	2.5	8,825,059		8,760,000	0.9926	2.4892
2005	3.5	8,271,363		8,070,975	0.9758	3.4603
2004	4.5	2,885,634		2,745,603	0.9515	4.4043
2003	5.5	4,684,727		4,204,193	0.8974	5.2429
2002	6.5	3,625,481		3,503,628	0.9664	6.3980
2001	7.5	2,698,188		2,668,819	0.9891	7.4754
2000	8.5	3,780,633		3,627,742	0.9596	8.3677
1999	9.5	3,061,831		2,912,662	0.9513	9.3770
1998	10.5	5,451,662		5,275,036	0.9676	10.3667
1997	11.5	5,689,845		5,000,094	0.8788	10.9742
1996	12.5	4,432,865		3,729,359	0.8413	11.8487
1995	13.5	3,958,192		3,733,845	0.9433	13.2177
1994	14.5	5,415,283		4,718,116	0.8713	13.6296
1993	15.5	4,297,570		4,115,941	0.9577	15.2242
1992	16.5		5,179,768	5,030,538	0.9712	16.4727
1991	17.5		7,361,002	6,766,104	0.9192	17.0007
1990	18.5		2,986,308	2,883,568	0.9656	18.3504
1989	19.5		2,122,887	1,991,090	0.9379	19.2987
1988	20.5		3,125,903	2,889,573	0.9244	20.2449
1987	21.5		2,893,288	2,733,976	0.9449	21.2751
1986	22.5		1,461,801	1,351,980	0.9249	22.1360
1985	23.5		1,090,816	1,027,863	0.9423	23.2704
1984	24.5		1,563,297	1,385,549	0.8863	24.2081
1983	25.5		1,844,266	1,631,310	0.8845	24.9555
1982	26.5		1,076,026	906,928	0.8428	25.9050
1981	27.5		1,752,072	1,446,595	0.8256	26.7603
1980	28.5		1,943,349	1,565,289	0.8055	27.5616
1979	29.5		1,845,523	1,340,243	0.7262	27.3712
1978	30.5		887,715	755,805	0.8514	29.6411
1977	31.5		1,536,554	1,201,140	0.7817	30.5411
1976	32.5		1,656,425	1,374,407	0.8297	31.1368
1975	33.5		1,295,264	1,009,209	0.7792	31.8868
1974	34.5		1,066,918	808,228	0.7575	31.9988
1973	35.5		1,058,855	773,324	0.7303	33.3640
1972	36.5		1,696,400	859,982	0.5069	31.2524

NARRAGANSETT ELECTRIC COMPANY
Distribution Plant
Account: 367.10 Underground Conductors and Devices

Age Distribution

				Experience to 12/31/2008		
Vintage	Age as of 12/31/2008	Derived Additions	1993 Opening Balance	Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1971	37.5		925,430	531,254	0.5741	33.2455
1970	38.5		736,105	314,254	0.4269	34.5813
1969	39.5		389,218	259,554	0.6669	35.8433
1968	40.5		316,695	115,549	0.3649	35.3268
1967	41.5		205,945	90,641	0.4401	37.4558
1966	42.5		6,177,411	2,410,915	0.3903	34.9546
1965	43.5		182		0.0000	34.4893
Total	13.1	$84,172,665	$54,195,421	$123,614,245	0.8934	

NARRAGANSETT ELECTRIC COMPANY

Distribution Plant

Account: 367.10 Underground Conductors and Devices

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1993	37,273,124	746,715	3,714,859		34,304,980
1994	34,304,980	750,296	80,696	(33,445)	34,941,135
1995	34,941,135		84,485		34,856,650
1996	34,856,650	1,587,029	110,886	15,576	36,348,369
1997	36,348,369	9,896,128	781,098	2	45,463,401
1998	45,463,401	1,906,532	405,822	6,331	46,970,442
1999	46,970,442	2,944,163	102,599	(539,462)	49,272,544
2000	49,272,544	7,053,953	336,966	20,199,468	76,188,999
2001	76,188,999	3,951,901	621,978		79,518,922
2002	79,518,922	5,398,793	677,423	1	84,240,293
2003	84,240,293	7,273,572	938,383		90,575,482
2004	90,575,482	3,407,095	1,138,221		92,844,356
2005	92,844,356	8,663,012	1,997,253	3,135	99,513,250
2006	99,513,250	8,852,715	1,480,916		106,885,049
2007	106,885,049	9,258,805	1,110,176	3,922	115,037,602
2008	115,037,602	9,748,724	1,172,080		123,614,245

NARRAGANSETT ELECTRIC COMPANY
Distribution Plant
Account: 367.10 Underground Conductors and Devices

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1993	40,104,354	3,404,357	3,714,859		39,793,852
1994	39,793,852	4,608,271	80,696		44,321,427
1995	44,321,427	3,169,688	84,485		47,406,630
1996	47,406,630	3,877,746	110,886	15,576	51,189,066
1997	51,189,066	4,250,125	781,098	2	54,658,095
1998	54,658,095	4,512,871	405,822		58,765,144
1999	58,765,144	2,357,668	102,599		61,020,213
2000	61,020,213	3,776,709	336,966	20,199,192	84,659,148
2001	84,659,148	2,698,187	621,978		86,735,357
2002	86,735,357	3,625,481	677,423		89,683,415
2003	89,683,415	4,684,413	938,383		93,429,445
2004	93,429,445	2,885,634	1,138,221		95,176,858
2005	95,176,858	8,271,363	1,997,253	3,135	101,454,103
2006	101,454,103	8,825,059	1,480,916		108,798,247
2007	108,798,247	8,980,538	1,110,176	3,922	116,672,531
2008	116,672,531	8,113,794	1,172,080		123,614,245

NARRAGANSETT ELECTRIC COMPANY
Distribution Plant
Account: 367.10 Underground Conductors and Devices

T-Cut: None
Placement Band: 1965-2008
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1993-1997	37.4	25.8	L2 *	11.87	26.8	S2 *	6.06	60.3	O4 *	8.25
1994-1998	74.7	53.9	L1	1.87	47.8	S0.5	1.59	145.2	SC *	1.30
1995-1999	76.1	58.3	L1	1.61	54.5	L1	1.51	151.9	SC *	1.28
1996-2000	75.3	59.2	L1	1.20	56.2	L1	1.16	150.8	SC *	0.98
1997-2001	73.0	57.1	L0.5	1.13	54.5	L1	1.05	142.1	SC *	1.16
1998-2002	70.7	58.9	L1	2.02	46.3	R2	1.18	43.9	R2.5	1.24
1999-2003	69.2	61.5	L0.5	2.35	47.8	R1.5	1.67	42.7	R2.5	1.70
2000-2004	58.7	48.7	L1	2.53	41.4	R1.5	1.63	39.6	R2	1.55
2001-2005	48.1	41.6	L1	1.80	38.2	S0.5	1.29	37.4	R1.5	1.22
2002-2006	0.0	41.9	L0.5	7.38	36.6	R1	6.51	36.2	R1	6.48
2003-2007	43.4	42.5	L0.5	2.23	37.0	R1	0.92	36.2	R1	0.84
2004-2008	38.5	40.6	L1	2.41	36.7	R1.5	1.05	36.5	R1.5	1.07

NARRAGANSETT ELECTRIC COMPANY
Distribution Plant
Account: 367.10 Underground Conductors and Devices

T-Cut: None
Placement Band: 1965-2008
Hazard Function: Proportion Retired
Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1993-2008	38.3	39.0	L1.5 *	2.48	36.7	S0.5	2.20	75.9	O4 *	2.00
1995-2008	45.9	46.4	L1	2.27	40.2	R1.5	0.93	38.9	R2	0.79
1997-2008	44.9	45.4	L1	2.26	39.6	R1.5	0.92	38.5	R1.5	0.81
1999-2008	45.0	45.7	L1	2.48	39.6	R1.5	0.97	38.5	R2	0.91
2001-2008	43.0	43.5	L1	2.48	38.2	R1.5	1.01	37.5	R1.5	0.92
2003-2008	41.0	42.1	L0.5	2.35	37.4	R1	0.97	36.7	R1.5	0.96
2005-2008	36.1	41.4	L0.5	3.38	37.0	R1	2.00	36.4	R1	2.08
2007-2008	41.7	44.3	L1.5 *	3.13	39.8	R2	1.82	39.2	R2	2.02

NARRAGANSETT ELECTRIC COMPANY
Distribution Plant
Account: 367.10 Underground Conductors and Devices

T-Cut: None
Placement Band: 1965-2008
Hazard Function: Proportion Retired
Weighting: Exposures

Progressing Band Life Analysis

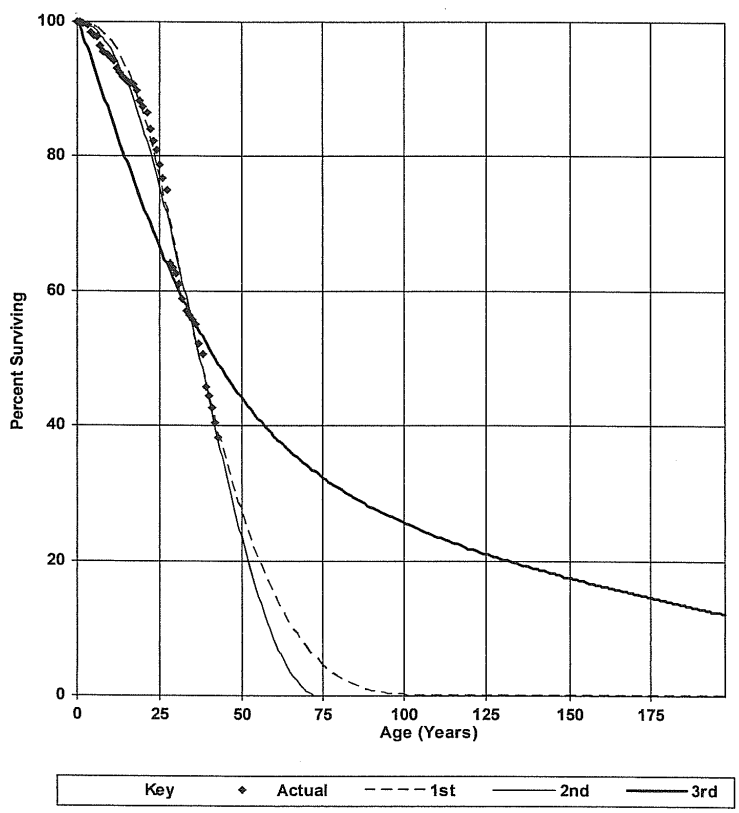
		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1993-1994	22.0	18.9	S1.5 *	23.82	22.8	S3 *	6.68	22.6	S3 *	7.36
1993-1996	37.5	24.5	L2 *	15.45	26.4	S3 *	6.03	46.3	O4 *	9.49
1993-1998	40.6	27.7	L2 *	10.24	28.1	S1.5 *	6.26	71.3	O4 *	7.82
1993-2000	48.9	32.6	L1.5 *	6.86	32.0	S1 *	5.59	93.4	O4 *	6.32
1993-2002	50.2	35.8	L1.5 *	5.08	34.7	S1 *	4.36	100.7	O4 *	4.42
1993-2004	47.4	37.5	L1.5 *	3.95	36.0	S1	3.58	97.3	O4 *	3.32
1993-2006	0.0	37.8	L1.5 *	6.50	36.0	S0.5	6.10	87.5	O4 *	6.38
1993-2008	38.3	39.0	L1.5 *	2.48	36.7	S0.5	2.20	75.9	O4 *	2.00

NARRAGANSETT ELECTRIC COMPANY
Distribution Plant
Account: 367.10 Underground Conductors and Devices

T-Cut: None
Placement Band: 1965-2008 Observation Band: 1993-2008
Hazard Function: Proportion Retired
Weighting: Exposures

Graphics Analysis

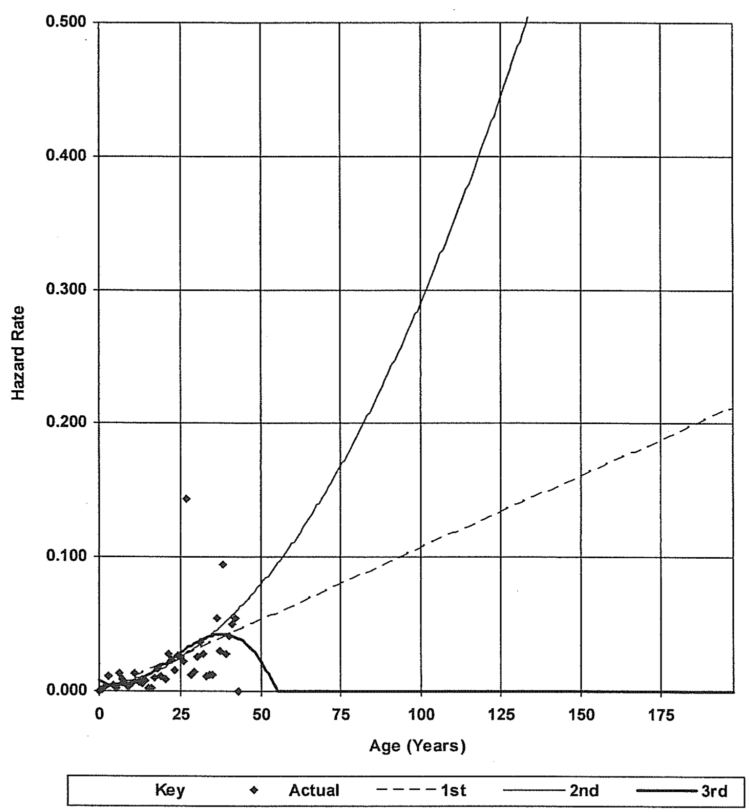
1st: 39.0-L1.5 2nd: 36.7-S0.5 3rd: 75.9-O4



NARRAGANSETT ELECTRIC COMPANY
Distribution Plant
Account: 367.10 Underground Conductors and Devices

T-Cut: None
Placement Band: 1965-2008 Observation Band: 1993-2008
Hazard Function: Proportion Retired
Weighting: Exposures

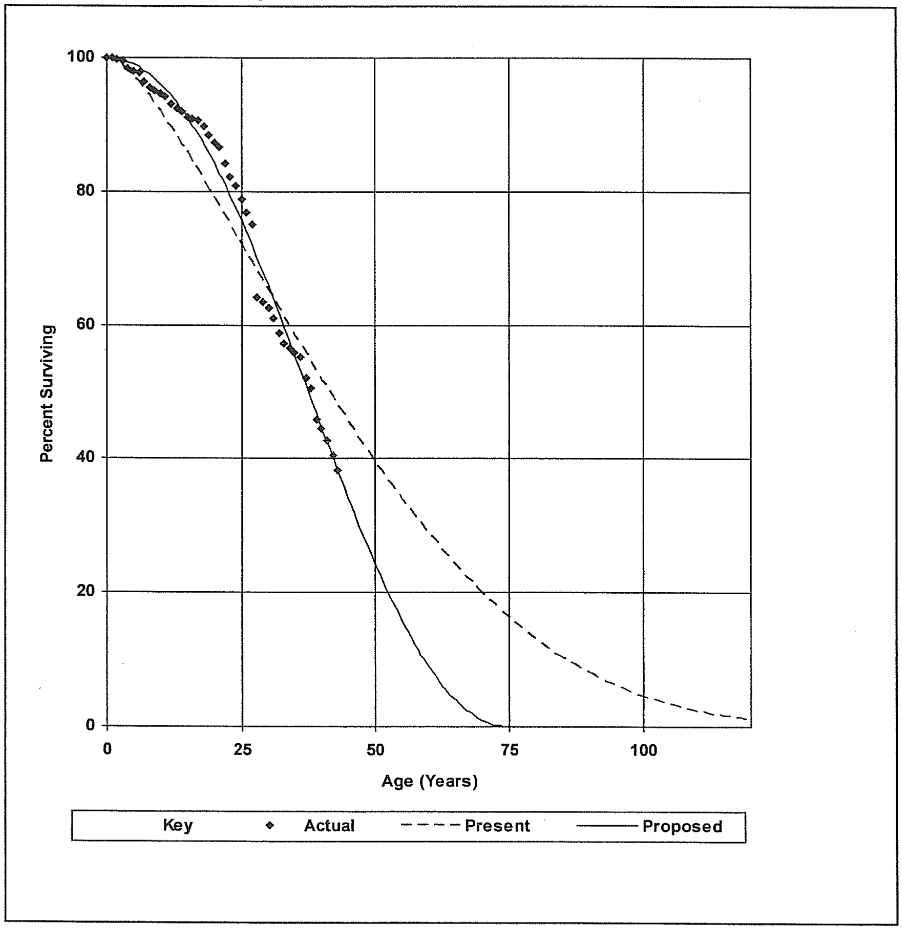
Polynomial Hazard Function 1st: 39.0-L1.5 2nd: 36.7-S0.5 3rd: 75.9-O4



NARRAGANSETT ELECTRIC COMPANY
Distribution Plant
Account: 367.10 Underground Conductors and Devices

T-Cut: None
Placement Band: 1965-2008
Observation Band: 1993-2008

Present and Proposed Projection Life Curves Present: 45.0-L0 Proposed: 37.0-S0.5



NARRAGANSETT ELECTRIC COMPANY
Distribution Plant
Account: 367.00 Underground Conductors and Devices

Unadjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	1-Yr Avg.	Amount	Pct.	1-Yr Avg.	Amount	Pct.	1-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
2004	1,138,221		0.0	0.0	330,826	29.1	29.1	(330,826)	-29.1	-29.1
2005	1,997,253		0.0	0.0	(268,205)	-13.4	-13.4	268,205	13.4	13.4
2006	1,480,916		0.0	0.0	621,130	41.9	41.9	(621,130)	-41.9	-41.9
2007	1,110,176		0.0	0.0	425,394	38.3	38.3	(425,394)	-38.3	-38.3
2008	1,172,080		0.0	0.0	720,091	61.4	61.4	(720,091)	-61.4	-61.4
Total	6,898,646		0.0		1,829,236	26.5		(1,829,236)	-26.5	

NARRAGANSETT ELECTRIC COMPANY
Distribution Plant
Account: 367.00 Underground Conductors and Devices

Adjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	1-Yr Avg.	Amount	Pct.	1-Yr Avg.	Amount	Pct.	1-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
2004	1,138,221		0.0	0.0	330,826	29.1	29.1	(330,826)	-29.1	-29.1
2005	1,997,253		0.0	0.0	(268,205)	-13.4	-13.4	268,205	13.4	13.4
2006	1,480,916		0.0	0.0	621,130	41.9	41.9	(621,130)	-41.9	-41.9
2007	1,110,176		0.0	0.0	425,394	38.3	38.3	(425,394)	-38.3	-38.3
2008	1,172,080		0.0	0.0	720,091	61.4	61.4	(720,091)	-61.4	-61.4
Total	6,898,646		0.0		1,829,236	26.5		(1,829,236)	-26.5	

Division 1-18

Request:

Please provide a comparison between the most recently approved depreciation rates and the depreciation rates proposed in NWA-2 Electric (2016 Electric Depreciation Study) using the same accounts and investment amounts shown on pages 76-78 (49-51 of 222) of NWA-2 Electric (2016 Electric Depreciation Study). Please provide the comparison requested electronically in Excel.

Response:

Please see Attachment DIV 1-18 for the comparison between the most recently approved depreciation rates and the depreciation rates proposed in Schedule NWA-2 Electric .

Prepared by or under the supervision of: Ned Allis

THE NARRAGANSETT ELECTRIC COMPANY
ELECTRIC PLANT

COMPARISON OF CURRENT AND PROPOSED DEPRECIATION PARAMETERS, RATES AND ACCRUALS AS OF DECEMBER 31, 2016

			CURRENT				PROPOSED				
	ACCOUNT	ORIGINAL COST AS OF DECEMBER 31, 2016	SURVIVOR CURVE	NET SALVAGE PERCENT	CALCULATED ANNUAL ACCRUAL AMOUNT	RATE	SURVIVOR CURVE	NET SALVAGE PERCENT	CALCULATED ANNUAL ACCRUAL AMOUNT	RATE	ACCRUAL INCREASE (DECREASE)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)=(9)-(5)
	ELECTRIC PLANT										
	TRANSMISSION PLANT										
352.00	STRUCTURES AND IMPROVEMENTS	5,796,211.36	55-S4	(20)	81,727	1.41	60-S1	(10)	54,769	0.94	(26,958)
353.00	STATION EQUIPMENT	292,202,561.12	60-L1	(20)	5,551,849	1.90	50-S0	(15)	7,094,446	2.43	1,542,597
354.00	TOWERS AND FIXTURES	1,554,741.21	50-R4	(20)	0	-	60-R4	(50)	115,672	7.44	115,672
355.00	POLES AND FIXTURES	337,856,717.24	45-S2	(20)	8,784,275	2.60	50-S0.5	(50)	10,561,779	3.13	1,777,504
356.00	OVERHEAD CONDUCTORS AND DEVICES	146,743,781.76	50-S1.5	(20)	3,360,433	2.29	50-R1.5	(50)	5,277,138	3.60	1,916,705
357.00	UNDERGROUND CONDUIT	4,830,086.33	50-R4	(20)	103,847	2.15	60-R4	0	44,512	0.92	(59,335)
358.00	UNDERGROUND CONDUCTORS AND DEVICES	28,376,661.24	45-L2	(20)	700,904	2.47	50-R3	(10)	477,146	1.68	(223,758)
359.00	ROADS AND TRAILS	492,181.70	60-R5	(20)	5,660	1.15	60-R4	0	4,057	0.82	(1,603)
	TOTAL TRANSMISSION PLANT	**817,852,941.96**			**18,588,695**	**2.27**			**23,629,519**	**2.89**	**5,040,824**
	DISTRIBUTION PLANT										
	DISTRIBUTION PLANT										
361.00	STRUCTURES AND IMPROVEMENTS	10,159,765.26	55-R4	(30)	230,627	2.27	60-R2	(10)	138,588	1.36	(92,039)
362.00	STATION EQUIPMENT	235,561,831.40	65-L0.5	(30)	4,640,568	1.97	55-S0	(15)	5,148,598	2.19	508,030
362.55	STATION EQUIPMENT - ENERGY MANAGEMENT SYSTEM	649,959.51	65-L0.5	(30)	12,804	1.97	15-S2.5	0	43,528	6.70	30,724
364.00	POLES, TOWERS AND FIXTURES	233,158,952.57	38-S2	(30)	8,347,091	3.58	45-S1.5	(75)	9,954,466	4.27	1,607,375
365.00	OVERHEAD CONDUCTORS AND DEVICES	303,496,087.80	40-L1.5	(30)	9,711,875	3.20	45-R1	(30)	8,032,325	2.65	(1,679,550)
366.10	UNDERGROUND MANHOLES	23,517,193.68	60-S4	(30)	442,123	1.88	60-S4	(10)	313,505	1.33	(128,618)
366.20	UNDERGROUND CONDUIT	48,770,763.64	60-S4	(30)	916,890	1.88	60-S4	(10)	755,438	1.55	(161,452)
367.10	UNDERGROUND CONDUCTORS AND DEVICES	169,982,453.89	37-S0.5	(30)	5,830,398	3.43	40-R1.5	(40)	5,814,523	3.42	(15,875)
368.10	LINE TRANSFORMERS - STATIONS	10,730,143.96	31-S1	(30)	405,599	3.78	40-S2.5	(50)	357,385	3.33	(48,214)
368.20	LINE TRANSFORMERS - BARE COST	100,521,675.49	31-S1	(30)	4,030,919	4.01	40-S2.5	(50)	3,560,040	3.54	(470,879)
368.30	LINE TRANSFORMERS - INSTALL COST	77,299,714.59	31-S1	(30)	3,130,638	4.05	40-S2.5	(50)	2,774,898	3.59	(355,740)
369.10	OVERHEAD SERVICES	80,498,717.41	40-S4	(30)	2,769,156	3.44	50-R3	(100)	4,053,214	5.04	1,284,058
369.20	UNDERGROUND SERVICES	22,670,051.68	40-S4	(30)	725,442	3.20	50-R3	(100)	1,103,631	4.87	378,189
370.10	METERS - BARE COST - DOMESTIC	26,720,548.87	23-R2	(30)	1,386,796	5.19	20-S2	(25)	1,498,924	5.61	112,128
370.20	METERS - INSTALL COST - DOMESTIC	9,862,221.59	23-R2	(30)	521,712	5.29	20-S2	(25)	573,035	5.81	51,323
370.30	METERS - BARE COST - LARGE	11,250,649.52	23-R2	(30)	591,784	5.26	20-S2	(25)	640,381	5.69	48,597
370.35	METERS - INSTALL COST - LARGE	9,087,749.94	23-R2	(30)	445,300	4.90	20-S2	(25)	466,076	5.13	20,776
371.00	INSTALLATION ON CUSTOMER'S PREMISES	119,824.57	35-L0	(30)	4,410	3.68	30-R1.5	(10)	4,328	3.61	(82)
373.10	STREET LIGHTING AND SIGNAL SYSTEMS - OVERHEAD	21,358,802.75	20-L2	(30)	1,204,636	5.64	30-R1.5	(30)	310,927	1.46	(893,709)
373.20	STREET LIGHTING AND SIGNAL SYSTEMS - UNDERGROUND	15,790,536.90	20-L2	(30)	892,165	5.65	30-R1.5	(30)	239,825	1.52	(652,340)
	TOTAL DISTRIBUTION PLANT	*1,411,207,645.02*			*46,240,933*	*3.28*			*45,783,635*	*3.24*	*(457,298)*
	DISTRIBUTION PLANT - BLOCK ISLAND TRANSMISSION SYSTEM										
362.00	STATION EQUIPMENT	17,910,356.77	60-L1	(20)	340,297	1.90	50-S0	(15)	414,800	2.32	74,503
365.00	OVERHEAD CONDUCTORS AND DEVICES	349,853.08	50-S1.5	(20)	8,012	2.29	50-R1.5	(50)	10,552	3.02	2,540
367.10	UNDERGROUND CONDUCTORS AND DEVICES	73,366,069.71	45-L2	(20)	1,812,142	2.47	40-R3	0	1,849,767	2.52	37,625
	TOTAL DISTRIBUTION PLANT - BLOCK ISLAND TRANSMISSTION SYSTEM	*91,626,279.56*			*2,160,451*	*2.36*			*2,275,119*	*2.48*	*114,668*
	TOTAL DISTRIBUTION PLANT	**1,502,833,924.58**			**48,401,384**	**3.22**			**48,058,754**	**3.20**	**(342,630)**

THE NARRAGANSETT ELECTRIC COMPANY
ELECTRIC PLANT

COMPARISON OF CURRENT AND PROPOSED DEPRECIATION PARAMETERS, RATES AND ACCRUALS AS OF DECEMBER 31, 2016

			CURRENT				PROPOSED				
	ACCOUNT	ORIGINAL COST AS OF DECEMBER 31, 2016	SURVIVOR CURVE	NET SALVAGE PERCENT	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	SURVIVOR CURVE	NET SALVAGE PERCENT	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	ACCRUAL INCREASE (DECREASE)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)=(9)-(5)
	GENERAL PLANT										
	DEPRECIABLE										
390.00	STRUCTURES AND IMPROVEMENTS	37,727,315.94	50-L1	(5)	845,092	2.24	50-R2	(5)	858,385	2.28	13,293
397.10	COMMUNICATION EQUIPMENT - SITE SPECIFIC	2,689,843.86	25-S3	(5)	125,347	4.66	25-S3	(5)	104,879	3.90	(20,468)
	TOTAL DEPRECIABLE	*40,417,159.80*			*970,439*	*2.40*			*963,264*	*2.38*	*(7,175)*
	AMORTIZED										
391.00	OFFICE FURNITURE AND EQUIPMENT										
	FULLY ACCRUED	35,491.08			486	1.37			0	-	(486)
	AMORTIZED	477,468.50	15-SQ	0	6,541	1.37	15-SQ	0	31,830	6.67	25,289
	TOTAL ACCOUNT 391	512,959.58			7,027	1.37			31,830	6.21	24,803
393.00	STORES EQUIPMENT	108,184.79	15-SQ	0	2,889	2.67	20-SQ	0	5,410	5.00	2,521
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	2,332,629.10	15-SQ	0	115,932	4.97	20-SQ	0	116,593	5.00	661
395.00	LABORATORY EQUIPMENT										
	FULL ACCRUED	333,809.18			14,220	4.26			0	-	(14,220)
	AMORTIZED	1,420,854.36	15-SQ	0	60,528	4.26	15-SQ	0	94,722	6.67	34,194
	TOTAL ACCOUNT 395	1,754,663.54			74,748	4.26			94,722	5.40	19,974
397.00	COMMUNICATION EQUIPMENT	18,366,251.69	15-SQ	0	1,103,812	6.01	20-SQ	0	918,314	5.00	(185,498)
398.00	MISCELLANEOUS EQUIPMENT	729,598.62	15-SQ	0	20,939	2.87	15-SQ	0	48,641	6.67	27,702
	TOTAL AMORTIZED	*23,804,287.32*			*1,325,347*	*5.57*			*1,215,510*	*5.11*	*(109,837)*
	TOTAL GENERAL PLANT	**64,221,447.12**			**2,295,786**	**3.57**			**2,178,774**	**3.39**	**(117,012)**
	TOTAL DEPRECIABLE PLANT	**2,384,908,313.66**			**69,285,865**	**2.91**			**73,867,047**	**3.10**	**4,581,182**
	UNRECOVERED RESERVE ADJUSTMENT										
391.00	OFFICE FURNITURE AND EQUIPMENT								44,292 *		44,292
393.00	STORES EQUIPMENT								11,066 *		11,066
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT								73,680 *		73,680
395.00	LABORATORY EQUIPMENT								88,904 *		88,904
397.00	COMMUNICATION EQUIPMENT								(497,168) *		(497,168)
398.00	MISCELLANEOUS EQUIPMENT								32,217 *		32,217
	TOTAL UNRECOVERED RESERVE ADJUSTMENT								**(247,009)**		**(247,009)**
	NONDEPRECIABLE PLANT AND ACCOUNTS NOT STUDIED										
303.00	MISCELLANEOUS INTANGIBLE PLANT	440,738.56									
330.00	LAND AND LAND RIGHTS	6,988.64									
331.00	STRUCTURES AND IMPROVEMENTS	1,993,756.61									
332.00	RESERVOIRS, DAMS AND WATERWAYS	1,125,688.80									
350.00	LAND AND LAND RIGHTS	21,653,791.06									
359.10	ASSET RETIREMENT OBLIGATION	67,114.08									
360.00	LAND AND LAND RIGHTS	15,466,146.58									
360.90	LAND AND LAND RIGHTS - BLOCK ISLAND TRANSMISSION SYSTEM	364,996.37									
374.00	ASSET RETIREMENT OBLIGATION	265,214.19									
389.00	LAND AND LAND RIGHTS	975,637.57									
399.00	OTHER TANGIBLE PROPERTY	16,065.20									
399.10	ASSET RETIREMENT OBLIGATION	391,601.32									
	TOTAL NONDEPRECIABLE PLANT	**42,767,738.98**									
	TOTAL ELECTRIC PLANT	**2,427,676,052.64**			**69,285,865**				**73,620,038**		**4,334,173**

* 5 YEAR AMORTIZATION OF RESERVE FOR UNRECOVERED RESERVE ADJUSTMENT

Division 1-19

Request:

Page 78 (51 of 222) of NWA-2 Electric (2016 Electric Depreciation Study) includes a note that states: "** 5 year Amortization of Adjusted Reserve related to implementation of Amortization Accounting."

(a) Please provide the support for the 5-year amortization period.

(b) Has this 5-year amortization period been approved by the Commission? If so, please provide a specific reference to the docket and page in the Order that approved the use of the "5 year Amortization of Adjusted Reserve related to implementation of Amortization Accounting."

Response:

(a) Footnote *** states "5 year amortization of reserve for unrecovered reserve adjustment." The five-year amortization period is the typical time between depreciation studies and is the most commonly used amortization period for this type of amortization. For example, a five-year amortization period has been used in jurisdictions such as Connecticut, Maryland, Washington, and Oregon.

(b) Mr. Allis is not aware of the Rhode Island Public Utilities Commission previously addressing the amortization of an unrecovered reserve adjustment. However, as noted in the Company's response to part (a) above, a five-year amortization of the unrecovered reserve has been used in other jurisdictions.

Prepared by or under the supervision of: Ned Allis

Division 1-20

Request:

Page 78 (51 of 222) of NWA-2 Electric (2016 Electric Depreciation Study) includes Book Reserve amounts for "Reserve Adjustment for Amortization."

(a) How are the book reserve amounts for "reserve adjustment for amortization" calculated?

(b) Please provide workpapers that support the book reserve amounts for "reserve adjustment for amortization." If possible, provide the workpapers and other documents requested electronically in Excel (or in text delimited format if not available in Excel.)

Response:

(a) The book reserve amounts referenced in this request are under a heading that states "Unrecovered Reserve Adjustment." These amounts are calculated by first determining the book reserve amounts for general plant amortization accounts that produce an accrual rate equal to one divided by the amortization period. The book reserve amount for the unrecovered reserve adjustment is then calculated by subtracting this amount from the total book reserve for the amortization account.

(b) There are no specific workpapers used to develop these amounts. Please refer to the Company's response to part (a) above.

Prepared by or under the supervision of: Ned Allis

Division 1-21

Request:

Please provide a brief description of the assets in each account included in NWA-2 Electric (2016 Electric Depreciation Study).

Response:

Please see Attachment DIV 1-21 for a brief description of the assets in each account included in Schedule NWA-2 Electric (2016 Electric Depreciation Study).

Prepared by or under the supervision of: Ned Allis

Utility Account Description	Segment	utility_account_id	retire_unit	company
30200-FRTRAN-FRANCHISES AND CONSENT	GAS	3020002	FRANCHISE & CONSENTS	5360-Narragansett Electric and Gas
30300-FRTRAN-MISCELLANEOUS INTANGIB	GAS	3030002	POLE, WOOD, 31' - 40', SO	5360-Narragansett Electric and Gas
30300-FRTRAN-MISCELLANEOUS INTANGIB	GAS	3030002	POLE, WOOD, 41' - 50', SO	5360-Narragansett Electric and Gas
30300-FRTRAN-MISCELLANEOUS INTANGIB	GAS	3030002	POLE, WOOD, 51' - 60', SO	5360-Narragansett Electric and Gas
30300-FRTRAN-MISCELLANEOUS INTANGIB	GAS	3030002	POLE, WOOD, 61' - 70', SO	5360-Narragansett Electric and Gas
30300-FRTRAN-MISCELLANEOUS INTANGIB	GAS	3030002	GUY & ANCHOR, SOLEY OWNED	5360-Narragansett Electric and Gas
30300-FRTRAN-MISCELLANEOUS INTANGIB	GAS	3030002	CROSSARM, WOOD	5360-Narragansett Electric and Gas
30300-FRTRAN-MISCELLANEOUS INTANGIB	GAS	3030002	COND, BARE OR CVRD, > 336 - 477	5360-Narragansett Electric and Gas
30300-FRTRAN-MISCELLANEOUS INTANGIB	GAS	3030002	GROUND, AERIAL	5360-Narragansett Electric and Gas
30300-FRTRAN-MISCELLANEOUS INTANGIB	GAS	3030002	INSULATOR, POST TYPE	5360-Narragansett Electric and Gas
30300-FRTRAN-MISCELLANEOUS INTANGIB	GAS	3030002	SWITCH, AIRBREAK	5360-Narragansett Electric and Gas
30300-FRTRAN-MISCELLANEOUS INTANGIB	GAS	3030002	BOILER OR BATTERY OF BOILERS	5360-Narragansett Electric and Gas
30300-FRTRAN-MISCELLANEOUS INTANGIB	GAS	3030002	C/I-HTR	5360-Narragansett Electric and Gas
30300-FRTRAN-MISCELLANEOUS INTANGIB	GAS	3030002	CAFETERIA EQP	5360-Narragansett Electric and Gas
30300-FRTRAN-MISCELLANEOUS INTANGIB	GAS	3030002	CAGE MODULAR	5360-Narragansett Electric and Gas
30300-FRTRAN-MISCELLANEOUS INTANGIB	GAS	3030002	CBNR	5360-Narragansett Electric and Gas
30300-FRTRAN-MISCELLANEOUS INTANGIB	GAS	3030002	CONTAINER	5360-Narragansett Electric and Gas
30300-FRTRAN-MISCELLANEOUS INTANGIB	GAS	3030002	ENSCAN EQUIPMENT	5360-Narragansett Electric and Gas
30300-FRTRAN-MISCELLANEOUS INTANGIB	GAS	3030002	ERT	5360-Narragansett Electric and Gas
30300-FRTRAN-MISCELLANEOUS INTANGIB	GAS	3030002	FIELD DATA CAPTURE UNIT	5360-Narragansett Electric and Gas
30300-FRTRAN-MISCELLANEOUS INTANGIB	GAS	3030002	GAS PIPING	5360-Narragansett Electric and Gas
30300-FRTRAN-MISCELLANEOUS INTANGIB	GAS	3030002	HOLDERS - STORAGE	5360-Narragansett Electric and Gas
30300-FRTRAN-MISCELLANEOUS INTANGIB	GAS	3030002	LAWN MOWER	5360-Narragansett Electric and Gas
30300-FRTRAN-MISCELLANEOUS INTANGIB	GAS	3030002	MAPPING	5360-Narragansett Electric and Gas
30300-FRTRAN-MISCELLANEOUS INTANGIB	GAS	3030002	METER PAINT SPRAYER	5360-Narragansett Electric and Gas
30300-FRTRAN-MISCELLANEOUS INTANGIB	GAS	3030002	METER SHOP EQP	5360-Narragansett Electric and Gas
30300-FRTRAN-MISCELLANEOUS INTANGIB	GAS	3030002	MISCELLANEOUS ITEMS (EA)	5360-Narragansett Electric and Gas
30300-FRTRAN-MISCELLANEOUS INTANGIB	GAS	3030002	ODORIZING FOGGING & METHANOL EQUIP	5360-Narragansett Electric and Gas
30300-FRTRAN-MISCELLANEOUS INTANGIB	GAS	3030002	PHOTOGRAPHY EQP	5360-Narragansett Electric and Gas
30300-FRTRAN-MISCELLANEOUS INTANGIB	GAS	3030002	PROJECTION EQP	5360-Narragansett Electric and Gas
30300-FRTRAN-MISCELLANEOUS INTANGIB	GAS	3030002	PROPANE EQP	5360-Narragansett Electric and Gas
30300-FRTRAN-MISCELLANEOUS INTANGIB	GAS	3030002	RECORDING EQP	5360-Narragansett Electric and Gas
30300-FRTRAN-MISCELLANEOUS INTANGIB	GAS	3030002	RESPIRATOR	5360-Narragansett Electric and Gas
30300-FRTRAN-MISCELLANEOUS INTANGIB	GAS	3030002	RG-06.00"	5360-Narragansett Electric and Gas
30300-FRTRAN-MISCELLANEOUS INTANGIB	GAS	3030002	SNAP TEST MACHINE	5360-Narragansett Electric and Gas
30300-FRTRAN-MISCELLANEOUS INTANGIB	GAS	3030002	SQUEEZE OFF TOOL	5360-Narragansett Electric and Gas
30300-FRTRAN-MISCELLANEOUS INTANGIB	GAS	3030002	STORAGE LOCKER	5360-Narragansett Electric and Gas
30300-FRTRAN-MISCELLANEOUS INTANGIB	GAS	3030002	TRANSMITTER	5360-Narragansett Electric and Gas

Utility Account Description	Segment	utility_account_id	retire_unit	company
30300-FRTRAN-MISCELLANEOUS INTANGIB	GAS	3030002	VIDEO EQUIPMENT	5360-Narragansett Electric and Gas
30300-FRTRAN-MISCELLANEOUS INTANGIB	GAS	3030002	WATER COOLER	5360-Narragansett Electric and Gas
30300-FRTRAN-MISCELLANEOUS INTANGIB	GAS	3030002	WATER METER	5360-Narragansett Electric and Gas
30300-FRTRAN-MISCELLANEOUS INTANGIB	GAS	3030002	WHTR	5360-Narragansett Electric and Gas
30300-RIELEC- Intangible Cap Softwa	GAS	3030012	Capitalized Software	5360-Narragansett Electric and Gas
31100-FRELEC-STRUCT & IMPROVE STEAM	GAS	3110001	Non-unitized	5360-Narragansett Electric and Gas
31100-FRELEC-STRUCT & IMPROVE STEAM	GAS	3110001	ALL WYMAN 4 RELATED PLANT	5360-Narragansett Electric and Gas
35200-FRELEC-STRUCT&IMPROVE TRANSMI	Electric	3520001	Non-unitized	5360-Narragansett Electric and Gas
35200-FRELEC-STRUCT&IMPROVE TRANSMI	Electric	3520001	OTHER ENCLOSURE	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	Non-unitized	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	Non-Utility Property - Land	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	FOUNDATION	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	BUILDING & ADDITIONS	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	Permanent Interior Walls	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	BUILDING HEATING/COOLING SYSTEM	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	Building Sitework	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	Paving	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	OTHER ENCLOSURE	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	HOISTS	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	Conversion-UG Cable	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	CEILING	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	EXTERIOR DOORS & WINDOWS	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	FINISH SYSTEMS - WINDOWS	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	SPECIAL CONSTRUCTION & EQUIPMENT	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	BUILDING POWER SUPPLY SYSTEM	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	ALARM OR SIGNAL SYSTEM	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	ALARM SYSTEM (ALL)	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	BUILDING SPECIALTY ELEC SYSTEM	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	BUILDING SANITARY SYSTEM	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	Storm Water Management System	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	LIGHTING & POWER SYSTEM	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	FLOOR COVERING	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	BILCO DOOR	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	BINS BUNKERS SHELVING	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	BOILER STEAM	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	BUILDINGS	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	CABLE/CONDUIT (1000 FT)	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	CABLE/CONDUIT (500 FT)	5360-Narragansett Electric and Gas

Utility Account Description	Segment	utility_account_id	retire_unit	company
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	COMMUNICATION SYSTEM INTRA-SITE	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	CORROSION CONTROL	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	CRANES & HOISTING EQUIPMENT	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	DRAINAGE SYSTEM - OUTSIDE	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	Elevators, Cranes, Etc.	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	EROSION PROTECTION	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	FIRE PROTECTION SYSTEM-OUTSIDE	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	GAS LEAKAGE DETECTOR SYSTEM	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	GAS MAIN	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	HEATING SYSTEM	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	HOLDING PONDS	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	HVAC	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	HVAC SYSTEM INTRA-SITE	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	Intrasite Communication System	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	LEASE STRUCTURE	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	LEASEHOLD IMPROVEMENT	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	MINOR BLDG & STRUCTURE	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	PROPANE STORAGE	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	RIP RAP BREAKWATER	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	ROOF	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	SECURITY GUARD BOOTH	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	SECURITY SYSTEM	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	STRUCTURAL FACILITIES	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	STRUCTURE / IMPROVEMENT	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	TRACK SYS-EXCEPT THOSE IN PLT EQUIP	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	Tunnels Intake and Discharge	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	TUNNELS-OUTSIDE	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	VAPORIZER EQUIPMENT	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	WASTE WATER TREATMENT SYSTEM	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	Water Meter and Supply System	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	FIRE FIGHTING EQUIPMENT	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	FUEL HANDLING ACCESORIES	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	HEATING & VENTILATING EQUIP PORT UN	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	HOUSE SERVICE COMPRESSED AIR SYSTEM	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	INTRA-PLANT COMMUNICATION SYSTEM	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	MACHINE POWER TOOLS	5360-Narragansett Electric and Gas
35200-FRTRAN-STRUCT&IMPROVE TRANSMI	Electric	3520002	Station Maintenance Equipment	5360-Narragansett Electric and Gas
35300-FRELEC-TRANSMISSION STATION E	Electric	3530001	Non-unitized	5360-Narragansett Electric and Gas

Utility Account Description	Segment	utility_account_id	retire_unit	company
35300-FRELEC-TRANSMISSION STATION E	Electric	3530001	TONE EQUIPMENT ISOLATING EQUIPMENT	5360-Narragansett Electric and Gas
35300-FRELEC-TRANSMISSION STATION E	Electric	3530001	TONE EQUIPMENT TRANSCEIVERS	5360-Narragansett Electric and Gas
35300-FRELEC-TRANSMISSION STATION E	Electric	3530001	BUSHING/BUSHING POTENTIAL DEVICE	5360-Narragansett Electric and Gas
35300-FRELEC-TRANSMISSION STATION E	Electric	3530001	STATIC VAR COMPENSATOR CAPACITOR	5360-Narragansett Electric and Gas
35300-FRELEC-TRANSMISSION STATION E	Electric	3530001	STATIC VAR COMPNSATR CONTRL DEVICE	5360-Narragansett Electric and Gas
35300-FRELEC-TRANSMISSION STATION E	Electric	3530001	STATIC VAR COMPENSATOR REACTOR	5360-Narragansett Electric and Gas
35300-FRELEC-TRANSMISSION STATION E	Electric	3530001	STATIC VAR COMPENSATOR THYRISTOR	5360-Narragansett Electric and Gas
35300-FRELEC-TRANSMISSION STATION E	Electric	3530001	DIAGRAM or MAP BOARDS	5360-Narragansett Electric and Gas
35300-FRELEC-TRANSMISSION STATION E	Electric	3530001	HQ Contr. Inst., Sys. Operators	5360-Narragansett Electric and Gas
35300-FRELEC-TRANSMISSION STATION E	Electric	3530001	HQ Bus Wires, Cables,Shapes&Insul.	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	Non-unitized	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	BATTERY EYEWASH STATION	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	CONDUIT	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	CAP CONTROL, SURGE CAPACITORS ALL T	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	FENCE	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	FOUNDATION	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	LIGHTNING ARRESTER	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	RETAINING WALL	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	ALL WYMAN 4 RELATED PLANT	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	Piping	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	GENERATOR	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	CONDUCTOR	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	INSTRUMENT TRANSFORMER	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	POLE	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	TRANSFER SWITCH	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	SWITCHGEAR	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	PANELBOARDS	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	STATION SERVICE TRANSFORMER	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	BATTERY BANK	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	DC POWER PANEL	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	BATTERY CHARGER	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	BUS INSULATOR	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	CABLE	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	POWER LINE CARRIER EQUIP. CABINETRY	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	PWR LINE EQUIP.LINE TUNING UNITS	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	POWER LINE CARRIER EQUIP. TRAPS	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	TONE EQUIPMENT CABINETRY	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	TONE EQUIPMENT ISOLATING EQUIPMENT	5360-Narragansett Electric and Gas

Utility Account Description	Segment	utility_account_id	retire_unit	company
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	TONE EQUIPMENT TRANSCEIVERS	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	GROUNDING GRID	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	GROUNDING CONDUCTOR	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	CIRCUIT BREAKER	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	CIRCUIT BREAKER INSTALLATION	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	CABINETS OTHER THAN RELAY	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	BUSHING/BUSHING POTENTIAL DEVICE	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	CIRCUIT SWITCHERS	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	MOTOR MECHANISM	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	DISCONNECT, AIR BREAK, LOADBREAK SW	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	TERMINATOR	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	NEUTRAL RESISTOR	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	SURGE ARRESTERS	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	POWER FUSE	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	RECLOSERS	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	MONITOR & ANNUNCIATOR EQUIPMENT	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	RELAY PANEL	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	RELAY PANEL CABINET	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	RELAY PANEL RELAYS & OTHER	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	DUCTBANK MANHOLES/HANDHOLES	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	DUCTBANK PRECAST TRENCH	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	CAPACITOR BANK	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	REACTOR	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	STATIC VAR COMPENSATOR CAPACITOR	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	STATIC VAR COMPNSATR CONTRL DEVICE	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	STATIC VAR COMPENSATOR REACTOR	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	STATIC VAR COMPENSATOR THYRISTOR	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	YARD LIGHTING	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	OTHER ENCLOSURE	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	POLE TAKE OFF	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	POWER TRANSFORMERS	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	PWR TRANSFORM FREE STANDING COOLER	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	VOLTAGE REGULATOR	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	OIL CONTAINMENT SYSTEM	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	RTU - ALARM SYSTEM	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	POWER TRANSFORMER INSTALLATION	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	RECLOSER INSTALLATION	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	VOLTAGE REGULATOR INSTALLATION	5360-Narragansett Electric and Gas

Utility Account Description	Segment	utility_account_id	retire_unit	company
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	PUMPS WITH MOTORS/COMPRESSORS	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	HOISTS	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	DIAGRAM or MAP BOARDS	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	TEST RU FOR TEST CONVERSION ONLY	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	ALARM OR SIGNAL SYSTEM	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	ALARM SYSTEM (ALL)	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	BUILDING SANITARY SYSTEM	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	YARD GRADING OR SURFACING	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	WALKWAY OR DRIVEWAY	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	HQ Contr. Inst., Sys. Operators	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	HQ Bus Wires, Cables,Shapes&Insul.	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	Wire & Cable	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	LIGHTING & POWER SYSTEM	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	BILCO DOOR	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	BINS BUNKERS SHELVING	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	BOILER STEAM	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	BUILDINGS	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	CABLE/CONDUIT (1000 FT)	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	CABLE/CONDUIT (500 FT)	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	COMMUNICATION SYSTEM INTRA-SITE	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	CORROSION CONTROL	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	CRANES & HOISTING EQUIPMENT	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	DRAINAGE SYSTEM - OUTSIDE	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	Elevators, Cranes, Etc.	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	EROSION PROTECTION	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	FIRE PROTECTION SYSTEM-OUTSIDE	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	GAS LEAKAGE DETECTOR SYSTEM	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	GAS MAIN	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	HEATING SYSTEM	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	HOLDING PONDS	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	HVAC	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	HVAC SYSTEM INTRA-SITE	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	Intrasite Communication System	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	LEASE STRUCTURE	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	LEASEHOLD IMPROVEMENT	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	MINOR BLDG & STRUCTURE	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	PROPANE STORAGE	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	RIP RAP BREAKWATER	5360-Narragansett Electric and Gas

Utility Account Description	Segment	utility_account_id	retire_unit	company
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	ROOF	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	SECURITY GUARD BOOTH	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	SECURITY SYSTEM	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	STRUCTURAL FACILITIES	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	STRUCTURE / IMPROVEMENT	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	TRACK SYS-EXCEPT THOSE IN PLT EQUIP	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	Tunnels Intake and Discharge	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	TUNNELS-OUTSIDE	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	VAPORIZER EQUIPMENT	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	WASTE WATER TREATMENT SYSTEM	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	Water Meter and Supply System	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	GENERATOR	5360-Narragansett Electric and Gas
35300-FRTRAN-TRANSMISSION STATION E	Electric	3530002	IPT BREAKER CAPABILITY	5360-Narragansett Electric and Gas
35310-FRTRAN-STA EQUIP POLL CONTL F	Electric	3531002	Non-unitized	5360-Narragansett Electric and Gas
35310-FRTRAN-STA EQUIP POLL CONTL F	Electric	3531002	OIL CONTAINMENT SYSTEM	5360-Narragansett Electric and Gas
35355-FRTRAN-STATION EQUIPMENT EMS	Electric	3535502	Non-unitized	5360-Narragansett Electric and Gas
35400-FRTRAN-TOWERS AND FIXTURES TR	Electric	3540002	Non-unitized	5360-Narragansett Electric and Gas
35400-FRTRAN-TOWERS AND FIXTURES TR	Electric	3540002	GUY & ANCHOR, SOLEY OWNED	5360-Narragansett Electric and Gas
35400-FRTRAN-TOWERS AND FIXTURES TR	Electric	3540002	TOWER, METAL, 0' - 50'	5360-Narragansett Electric and Gas
35400-FRTRAN-TOWERS AND FIXTURES TR	Electric	3540002	TOWER, METAL, 101' - 150'	5360-Narragansett Electric and Gas
35400-FRTRAN-TOWERS AND FIXTURES TR	Electric	3540002	TOWER, METAL, 151' - 200'	5360-Narragansett Electric and Gas
35400-FRTRAN-TOWERS AND FIXTURES TR	Electric	3540002	TOWER, METAL, 51' - 100'	5360-Narragansett Electric and Gas
35400-FRTRAN-TOWERS AND FIXTURES TR	Electric	3540002	PLATFORM/SHED	5360-Narragansett Electric and Gas
35400-FRTRAN-TOWERS AND FIXTURES TR	Electric	3540002	FENCE	5360-Narragansett Electric and Gas
35400-FRTRAN-TOWERS AND FIXTURES TR	Electric	3540002	FOUNDATION	5360-Narragansett Electric and Gas
35400-FRTRAN-TOWERS AND FIXTURES TR	Electric	3540002	STRUCTURAL METAL	5360-Narragansett Electric and Gas
35400-FRTRAN-TOWERS AND FIXTURES TR	Electric	3540002	BIRD PROTECTION	5360-Narragansett Electric and Gas
35400-FRTRAN-TOWERS AND FIXTURES TR	Electric	3540002	TOWER ALARM KIT	5360-Narragansett Electric and Gas
35400-FRTRAN-TOWERS AND FIXTURES TR	Electric	3540002	TOWER LIGHTING KIT	5360-Narragansett Electric and Gas
35400-FRTRAN-TOWERS AND FIXTURES TR	Electric	3540002	EUA CONVERSION ASSETS	5360-Narragansett Electric and Gas
35500-FRELEC-POLES AND FIXTURES TRA	Electric	3550001	POLE, METAL, 30' & UNDER, SO	5360-Narragansett Electric and Gas
35500-FRELEC-POLES AND FIXTURES TRA	Electric	3550001	POLE, METAL, 31' - 40', SO	5360-Narragansett Electric and Gas
35500-FRELEC-POLES AND FIXTURES TRA	Electric	3550001	POLE, METAL, 41' - 50', SO	5360-Narragansett Electric and Gas
35500-FRELEC-POLES AND FIXTURES TRA	Electric	3550001	POLE, METAL, 51' - 60', SO	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	Non-unitized	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE, METAL, 30' & UNDER, SO	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE, METAL, 31' - 40', SO	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE, METAL, 41' - 50', SO	5360-Narragansett Electric and Gas

Utility Account Description	Segment	utility_account_id	retire_unit	company
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE, METAL, 51' - 60', JO	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE, METAL, 51' - 60', SO	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE, METAL, 61' - 70', SO	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE, METAL, 71' - 80', SO	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE, METAL, 81' - 90', SO	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE, METAL, 91' - 100', SO	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE, METAL, 101' - 110', SO	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE, METAL, 111' - 120', SO	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE, METAL, 121' - 130', SO	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE, METAL, 131' - 140', SO	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE, METAL, 141' - 150', SO	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE, METAL, 151' - 160', SO	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE, WOOD, 30' & UNDER, JO	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE, WOOD, 30' & UNDER, SO	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE, WOOD, 31' - 40', JO	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE, WOOD, 31' - 40', SO	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE, WOOD, 41' - 50', JO	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE, WOOD, 41' - 50', SO	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE, WOOD, 51' - 60', JO	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE, WOOD, 51' - 60', SO	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE, WOOD, 61' - 70', JO	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE, WOOD, 61' - 70', SO	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE, WOOD, 71' - 80', JO	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE, WOOD, 71' - 80', SO	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE, WOOD, 81' - 90', SO	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE, WOOD, 91' - 100', SO	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE, WOOD, 101' - 110', SO	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE, WOOD, 111' - 120', SO	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE, WOOD, 121' - 130', SO	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE, CONCRETE, 31' - 40', SO	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE, CONCRETE, 51' - 60', SO	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE, CONCRETE, 61' - 70', SO	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	GUY Jointly Owned	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	GUY & ANCHOR, SOLEY OWNED	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE TOP PIN	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE STRUCTURE, METAL, 40' & UNDER	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE STRUCTURE, METAL, 41' - 50'	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE STRUCTURE, METAL, 51' - 60'	5360-Narragansett Electric and Gas

Utility Account Description	Segment	utility_account_id	retire_unit	company
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE STRUCTURE, METAL, 61' - 70'	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE STRUCTURE, METAL, 71' - 80'	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE STRUCTURE, METAL, 81' - 90'	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE STRUCTURE, METAL, 91' - 100'	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	PLATFORM/SHED	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	POLE ARM, WOOD	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	CROSSARM, METAL	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	CROSSARM, WOOD	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	BARRIER	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	FENCE	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	FOUNDATION	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	LANDSCAPING	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	STRUCTURAL METAL	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	BIRD PROTECTION	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	Conversion-Poles	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	PSNH LOCATION 4181	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	TEST RU FOR TEST CONVERSION ONLY	5360-Narragansett Electric and Gas
35500-FRTRAN-POLES AND FIXTURES TRA	Electric	3550002	CROSSARM, FIBREGLASS	5360-Narragansett Electric and Gas
35600-FRELEC-TRANSMSN CONDUCTR NEW	Electric	3560001	FAULT INDICATORS, ALL TYPES	5360-Narragansett Electric and Gas
35600-FRELEC-TRANSMSN CONDUCTR NEW	Electric	3560001	CAPACITOR UNIT, 25 - < 50 KVAR	5360-Narragansett Electric and Gas
35600-FRELEC-TRANSMSN CONDUCTR NEW	Electric	3560001	CAPACITOR UNIT, 50 - < 100 KVAR	5360-Narragansett Electric and Gas
35600-FRELEC-TRANSMSN CONDUCTR NEW	Electric	3560001	CAPACITOR UNIT, 300 - < 400 KVAR	5360-Narragansett Electric and Gas
35600-FRELEC-TRANSMSN CONDUCTR NEW	Electric	3560001	CAPACITOR UNIT, 400 & GRTR KVAR	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	Non-unitized	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	INSULATORS, ALL TYPES	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	FAULT INDICATORS, ALL TYPES	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	AERIAL CABLE, 1/C, > 1/0 - 4/0	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	COND, BARE OR CVRD, < 1/0	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	COND, BARE OR CVRD, 1/0	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	COND, BARE OR CVRD, 2/0	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	COND, BARE OR CVRD, > 2/0 - 4/0	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	COND, BARE OR CVRD, > 4/0 - 336	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	COND, BARE OR CVRD, > 336 - 477	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	COND, BARE OR CVRD, > 477 - 636	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	COND, BARE OR CVRD, > 636 - 795	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	COND, BARE OR CVRD, > 795 - 1113	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	COND, BARE OR CVRD, > 1113 - 1590	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	COND, BARE OR CVRD, > 1590	5360-Narragansett Electric and Gas

Utility Account Description	Segment	utility_account_id	retire_unit	company
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	CAPACITOR UNIT, UNDER 25 KVAR	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	CAPACITOR UNIT, 25 - < 50 KVAR	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	CAPACITOR UNIT, 50 - < 100 KVAR	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	CAPACITOR UNIT, 150 - < 200 KVAR	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	CAPACITOR UNIT, 200 - < 300 KVAR	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	CAPACITOR UNIT, 300 - < 400 KVAR	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	CAPACITOR UNIT, 400 & GRTR KVAR	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	CAP CONTROL, SURGE CAPACITORS ALL T	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	CONDUCTOR, PROTECTIVE CONTROL	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	CONDUIT, PROTECTIVE CONTROL	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	GROUND, AERIAL	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	GROUND, AERIAL, FIBER OPTIC	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	GROUND, BURIED COUNTERPOISE	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	GROUND, EQUIPMENT	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	GROUND, WIRE MESH MAT	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	INSULATOR, DISC TYPE	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	INSULATOR, PIN TYPE	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	INSULATOR, POST TYPE	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	INSULATOR, STRUT TYPE	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	INSULATOR, SUSPENSION/TENSION TYPE	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	LIGHTNING ARRESTER	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	TRANSMISSION LINE MONITORING SYS	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	TRNFMR, INSTRUMENT, PROTECTIVE	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	SWITCH, AIRBREAK	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	SWITCH, DISCONNECT	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	SWITCH, NON RCLSNG, 1 OR 3 PH	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	SWITCH, LOADBREAK	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	SWITCH, AUTO RCLSNG, 3 PH	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	NEUTRAL GRD RETURN CONDUCTOR	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	POWER LINE CARRIER EQUIP. TRAPS	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	MOTOR MECHANISM	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	PSNH LOCATION 4181	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	TEST RU FOR TEST CONVERSION ONLY	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	FIBER OPTIC CABLE - ALL SIZES	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	DISTRIBUTED AUTOMATED SWITCH	5360-Narragansett Electric and Gas
35600-FRTRAN-TRANSMSN CONDUCTR NEW	Electric	3560002	AERIAL CABLE, 3/C 4/0	5360-Narragansett Electric and Gas
35610-FRELEC-COND AND DEVICES ON ST	Electric	3561001	FAULT INDICATORS, ALL TYPES	5360-Narragansett Electric and Gas
35610-FRELEC-COND AND DEVICES ON ST	Electric	3561001	COND, BARE OR CVRD, > 795 - 1113	5360-Narragansett Electric and Gas

Utility Account Description	Segment	utility_account_id	retire_unit	company
35610-FRELEC-COND AND DEVICES ON ST	Electric	3561001	CAPACITOR UNIT, UNDER 25 KVAR	5360-Narragansett Electric and Gas
35610-FRELEC-COND AND DEVICES ON ST	Electric	3561001	CAPACITOR UNIT, 25 - < 50 KVAR	5360-Narragansett Electric and Gas
35610-FRELEC-COND AND DEVICES ON ST	Electric	3561001	CAPACITOR UNIT, 50 - < 100 KVAR	5360-Narragansett Electric and Gas
35610-FRELEC-COND AND DEVICES ON ST	Electric	3561001	GROUND, AERIAL, FIBER OPTIC	5360-Narragansett Electric and Gas
35610-FRELEC-COND AND DEVICES ON ST	Electric	3561001	FIBER OPTIC CABLE - ALL SIZES	5360-Narragansett Electric and Gas
35610-FRTRAN-COND AND DEVICES ON ST	Electric	3561002	Non-unitized	5360-Narragansett Electric and Gas
35610-FRTRAN-COND AND DEVICES ON ST	Electric	3561002	INSULATORS, ALL TYPES	5360-Narragansett Electric and Gas
35610-FRTRAN-COND AND DEVICES ON ST	Electric	3561002	FAULT INDICATORS, ALL TYPES	5360-Narragansett Electric and Gas
35610-FRTRAN-COND AND DEVICES ON ST	Electric	3561002	COND, BARE OR CVRD, > 636 - 795	5360-Narragansett Electric and Gas
35610-FRTRAN-COND AND DEVICES ON ST	Electric	3561002	COND, BARE OR CVRD, > 795 - 1113	5360-Narragansett Electric and Gas
35610-FRTRAN-COND AND DEVICES ON ST	Electric	3561002	CAPACITOR UNIT, UNDER 25 KVAR	5360-Narragansett Electric and Gas
35610-FRTRAN-COND AND DEVICES ON ST	Electric	3561002	CAPACITOR UNIT, 25 - < 50 KVAR	5360-Narragansett Electric and Gas
35610-FRTRAN-COND AND DEVICES ON ST	Electric	3561002	CAPACITOR UNIT, 50 - < 100 KVAR	5360-Narragansett Electric and Gas
35610-FRTRAN-COND AND DEVICES ON ST	Electric	3561002	GROUND, AERIAL	5360-Narragansett Electric and Gas
35610-FRTRAN-COND AND DEVICES ON ST	Electric	3561002	GROUND, BURIED COUNTERPOISE	5360-Narragansett Electric and Gas
35610-FRTRAN-COND AND DEVICES ON ST	Electric	3561002	GROUND, EQUIPMENT	5360-Narragansett Electric and Gas
35610-FRTRAN-COND AND DEVICES ON ST	Electric	3561002	INSULATOR, SUSPENSION/TENSION TYPE	5360-Narragansett Electric and Gas
35610-FRTRAN-COND AND DEVICES ON ST	Electric	3561002	SWITCH, AIRBREAK	5360-Narragansett Electric and Gas
35610-FRTRAN-COND AND DEVICES ON ST	Electric	3561002	SWITCH, AUTO RCLSNG, 3 PH	5360-Narragansett Electric and Gas
35610-FRTRAN-COND AND DEVICES ON ST	Electric	3561002	NEUTRAL GRD RETURN CONDUCTOR	5360-Narragansett Electric and Gas
35610-FRTRAN-COND AND DEVICES ON ST	Electric	3561002	Conversion-OH Conductor Tower	5360-Narragansett Electric and Gas
35610-FRTRAN-COND AND DEVICES ON ST	Electric	3561002	FIBER OPTIC CABLE - ALL SIZES	5360-Narragansett Electric and Gas
35610-FRTRAN-COND AND DEVICES ON ST	Electric	3561002	DISTRIBUTED AUTOMATED SWITCH	5360-Narragansett Electric and Gas
35610-FRTRAN-COND AND DEVICES ON ST	Electric	3561002	AERIAL CABLE, 3/C 4/0	5360-Narragansett Electric and Gas
35620-FRELEC-CONDUCTOR AND DEVICES	Electric	3562001	CAPACITOR UNIT, UNDER 25 KVAR	5360-Narragansett Electric and Gas
35620-FRELEC-CONDUCTOR AND DEVICES	Electric	3562001	CAPACITOR UNIT, 25 - < 50 KVAR	5360-Narragansett Electric and Gas
35620-FRELEC-CONDUCTOR AND DEVICES	Electric	3562001	CAPACITOR UNIT, 50 - < 100 KVAR	5360-Narragansett Electric and Gas
35620-FRELEC-CONDUCTOR AND DEVICES	Electric	3562001	CAP CONTROL, SURGE CAPACITORS ALL T	5360-Narragansett Electric and Gas
35620-FRELEC-CONDUCTOR AND DEVICES	Electric	3562001	FIBER OPTIC CABLE - ALL SIZES	5360-Narragansett Electric and Gas
35620-FRTRAN-CONDUCTOR AND DEVICES	Electric	3562002	Non-unitized	5360-Narragansett Electric and Gas
35620-FRTRAN-CONDUCTOR AND DEVICES	Electric	3562002	INSULATORS, ALL TYPES	5360-Narragansett Electric and Gas
35620-FRTRAN-CONDUCTOR AND DEVICES	Electric	3562002	AERIAL CABLE, 1/C, > 1/0 - 4/0	5360-Narragansett Electric and Gas
35620-FRTRAN-CONDUCTOR AND DEVICES	Electric	3562002	CAPACITOR UNIT, UNDER 25 KVAR	5360-Narragansett Electric and Gas
35620-FRTRAN-CONDUCTOR AND DEVICES	Electric	3562002	CAPACITOR UNIT, 25 - < 50 KVAR	5360-Narragansett Electric and Gas
35620-FRTRAN-CONDUCTOR AND DEVICES	Electric	3562002	CAPACITOR UNIT, 50 - < 100 KVAR	5360-Narragansett Electric and Gas
35620-FRTRAN-CONDUCTOR AND DEVICES	Electric	3562002	CAP CONTROL, SURGE CAPACITORS ALL T	5360-Narragansett Electric and Gas
35620-FRTRAN-CONDUCTOR AND DEVICES	Electric	3562002	GROUND, EQUIPMENT	5360-Narragansett Electric and Gas
35620-FRTRAN-CONDUCTOR AND DEVICES	Electric	3562002	SWITCH, AUTO RCLSNG, 3 PH	5360-Narragansett Electric and Gas

Utility Account Description	Segment	utility_account_id	retire_unit	company
35620-FRTRAN-CONDUCTOR AND DEVICES	Electric	3562002	Conversion-OH Conductor Pole	5360-Narragansett Electric and Gas
35620-FRTRAN-CONDUCTOR AND DEVICES	Electric	3562002	FIBER OPTIC CABLE - ALL SIZES	5360-Narragansett Electric and Gas
35620-FRTRAN-CONDUCTOR AND DEVICES	Electric	3562002	DISTRIBUTED AUTOMATED SWITCH	5360-Narragansett Electric and Gas
35620-FRTRAN-CONDUCTOR AND DEVICES	Electric	3562002	AERIAL CABLE, 3/C 4/0	5360-Narragansett Electric and Gas
35630-FRTRAN-TELECOM INSTALLATION	Electric	3563002	ANTENNA/ANTENNA MAST	5360-Narragansett Electric and Gas
35630-FRTRAN-TELECOM INSTALLATION	Electric	3563002	FIXED RADIO EQUIP - RF LINKS	5360-Narragansett Electric and Gas
35710-FRTRAN-UG TRANS MANHOLES & HA	Electric	3571002	Non-unitized	5360-Narragansett Electric and Gas
35710-FRTRAN-UG TRANS MANHOLES & HA	Electric	3571002	HANDHOLE, 0 - 400 CF	5360-Narragansett Electric and Gas
35710-FRTRAN-UG TRANS MANHOLES & HA	Electric	3571002	MANHOLE, 401 - 3000 CF	5360-Narragansett Electric and Gas
35710-FRTRAN-UG TRANS MANHOLES & HA	Electric	3571002	MANHOLE/VLT PUMP/DRAINAGE SYSTEM	5360-Narragansett Electric and Gas
35720-FRTRAN-UG TRANSMISSION CONDUI	Electric	3572002	Non-unitized	5360-Narragansett Electric and Gas
35720-FRTRAN-UG TRANSMISSION CONDUI	Electric	3572002	CONDUIT	5360-Narragansett Electric and Gas
35720-FRTRAN-UG TRANSMISSION CONDUI	Electric	3572002	RISER, ALL SIZES & KINDS	5360-Narragansett Electric and Gas
35720-FRTRAN-UG TRANSMISSION CONDUI	Electric	3572002	DUCT BANK	5360-Narragansett Electric and Gas
35720-FRTRAN-UG TRANSMISSION CONDUI	Electric	3572002	FIBER OPTIC CABLE - ALL SIZES	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	Non-unitized	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	COND, BARE OR CVRD, > 2/0 - 4/0	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	CABLE, LEAD CVRD, 1/C, < 1/0	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	CABLE, LEAD CVRD, 1/C, > 1/0 - 4/0	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	CABLE, LEAD CVRD, 1/C, > 4/0-350	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	CABLE, LEAD CVRD, 1/C, > 350-500	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	CABLE, LEAD CVRD, 3/C, > 1/0-4/0	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	CABLE, LEAD CVRD, 3/C, > 4/0-350	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	CABLE, LEAD CVRD, 3/C, > 350-500	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	CABLE, LEAD CVRD, 3/C, > 500-750	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	CABLE, LEAD CVRD, 3/C, > 750-1000	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	CABLE, NONMTL CVRD, 1/C, > #2-1/0	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	CABLE, NONMTL CVRD, 1/C, > 1/0-4/0	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	CABLE, NONMTL CVRD, 1/C, > 4/0-350	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	CABLE, NONMTL CVRD, 1/C, > 350-500	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	CABLE, NONMTL CVRD, 1/C, > 500-750	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	CABLE, NONMTL CVRD, 1/C, > 1500	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	CABLE, NONMTL CVRD, 3/C, > 350-500	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	CABLE, SUBMRN, 1/C, > 4/0 - 350	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	CABLE, SUBMRN, 1/C, > 750 - 1000	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	CABLE, SUBMRN, 1/C, > 1500	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	CABLE, SUBMRN, 3/C, > 4/0 - 350	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	CABLE, SUBMRN, 3/C, > 350 - 500	5360-Narragansett Electric and Gas

Utility Account Description	Segment	utility_account_id	retire_unit	company
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	CABLE SPREADER	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	CABLE, AL CVRD, 1/C, < 500 - 750	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	CABLE, AL CVRD, OIL,DB,1/C, < 1500	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	CABLE, AL CVRD, OIL,DB,1/C,<500-750	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	CABLE, AL CVRD,OIL,DB,3/C,< 500-750	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	CABLE, LEAD CVRD, OIL, 1/C,750-1000	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	CABLE, LEAD CVRD, OIL,1/C,1000-1500	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	CABLE, LEAD CVRD, OIL,1/C,1500-2000	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	CABLE, LEAD CVRD, OIL,1/C,350-500	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	CABLE, CONTROL	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	CABLE, NONMTL CVRD, OIL,1/C, > 2000	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	BONDING TRNFMR	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	FIRE EXTINGUISHING SYSTEM	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	GROUND, EQUIPMENT	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	OIL/GAS CBL ACCES., BAL PRESS RESVR	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	OIL/GAS CBL ACCES., CTL CABINET	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	OIL/GAS CBL ACCES., DIFF PRES RELAY	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	OIL/GAS CBL ACCES., FDR RESERVOIR	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	OIL/GAS CBL ACCES., GAS TANK	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	OIL/GAS CBL ACCES., GAUGE/INSTRMT	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	OIL/GAS CBL ACCES., JNT STOP/SEMI	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	OIL/GAS CBL ACCES., JNT, TRIFURCATE	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	OIL/GAS CBL ACCES., JOINT NORMAL	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	OIL/GAS CBL ACCES., PRESS RESEVR	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	OIL/GAS CBL ACCES., PUMP PLANT	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	OIL/GAS CBL ACCES., TERM ASSEMBLY	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	OIL/GAS CBL ACCES., VALVE	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	OIL/GAS CBL ACCES., VALVE PANEL	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	POTHEAD/TERMINATOR	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	RECTIFIER/POLARIZATION CELL	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	RESISTOR	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	SWITCH, NON RCLSNG, 1 OR 3 PH	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	CATHODIC PROTECTION/ANODE SYSTEM	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	CABLE, NONMTL CVRD, 1/C, < #2	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	SWTCHGR, PADMNT OR SUBSURFACE	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	CABLE,NONMTL CVRD,GAS,1/C,> 500-750	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	DUCT BANK	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	ANTENNA/ANTENNA MAST	5360-Narragansett Electric and Gas

Utility Account Description	Segment	utility_account_id	retire_unit	company
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	FIBER OPTIC CABLE - ALL SIZES	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	FIXED RADIO EQUIP - RF LINKS	5360-Narragansett Electric and Gas
35800-FRTRAN-UG TRANS CONDUCTORS &	Electric	3580002	FIRE PROTECTION SYSTEM (ALL)	5360-Narragansett Electric and Gas
35900-FRTRAN-ROADS AND TRAILS	Electric	3590002	Non-unitized	5360-Narragansett Electric and Gas
35900-FRTRAN-ROADS AND TRAILS	Electric	3590002	LAND	5360-Narragansett Electric and Gas
35900-FRTRAN-ROADS AND TRAILS	Electric	3590002	ROADS	5360-Narragansett Electric and Gas
35900-FRTRAN-ROADS AND TRAILS	Electric	3590002	BRIDGES	5360-Narragansett Electric and Gas
36000-FRTRAN-LAND&LANDRIGHTS FUT NE	GAS	3600002	LAND	5360-Narragansett Electric and Gas
36000-RIELEC-LAND & LAND RIGHTS NEW	GAS	3600012	Non-unitized	5360-Narragansett Electric and Gas
36000-RIELEC-LAND & LAND RIGHTS NEW	GAS	3600012	LAND	5360-Narragansett Electric and Gas
36000-RIELEC-LAND & LAND RIGHTS NEW	GAS	3600012	LAND RIGHTS & ADDITIONAL COSTS	5360-Narragansett Electric and Gas
36010-RIELEC-LAND STRUCTURES & DIST	GAS	3601012	Non-unitized	5360-Narragansett Electric and Gas
36010-RIELEC-LAND STRUCTURES & DIST	GAS	3601012	LAND	5360-Narragansett Electric and Gas
36020-RIELEC-LAND UNDER DISTRIBUTIO	GAS	3602012	Non-unitized	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	Non-unitized	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	FOUNDATION	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	BUILDING & ADDITIONS	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	Permanent Interior Walls	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	Roofing Shingles	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	BUILDING HEATING/COOLING SYSTEM	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	Building Sitework	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	Paving	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	OTHER ENCLOSURE	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	HOISTS	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	CEILING	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	ELEVATOR	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	EXTERIOR DOORS & WINDOWS	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	FINISH SYSTEMS - WINDOWS	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	ALARM OR SIGNAL SYSTEM	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	ALARM SYSTEM (ALL)	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	BUILDING SANITARY SYSTEM	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	Storm Water Management System	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	LIGHTING & POWER SYSTEM	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	FLOOR COVERING	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	BILCO DOOR	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	BINS BUNKERS SHELVING	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	BOILER STEAM	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	BUILDINGS	5360-Narragansett Electric and Gas

Utility Account Description	Segment	utility_account_id	retire_unit	company
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	CABLE/CONDUIT (1000 FT)	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	CABLE/CONDUIT (500 FT)	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	COMMUNICATION SYSTEM INTRA-SITE	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	CORROSION CONTROL	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	CRANES & HOISTING EQUIPMENT	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	DRAINAGE SYSTEM - OUTSIDE	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	Elevators, Cranes, Etc.	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	EROSION PROTECTION	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	FIRE PROTECTION SYSTEM-OUTSIDE	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	GAS LEAKAGE DETECTOR SYSTEM	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	GAS MAIN	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	HEATING SYSTEM	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	HOLDING PONDS	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	HVAC	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	HVAC SYSTEM INTRA-SITE	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	Intrasite Communication System	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	LEASE STRUCTURE	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	LEASEHOLD IMPROVEMENT	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	MINOR BLDG & STRUCTURE	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	PROPANE STORAGE	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	RIP RAP BREAKWATER	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	ROOF	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	SECURITY GUARD BOOTH	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	SECURITY SYSTEM	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	STRUCTURAL FACILITIES	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	STRUCTURE / IMPROVEMENT	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	TRACK SYS-EXCEPT THOSE IN PLT EQUIP	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	Tunnels Intake and Discharge	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	TUNNELS-OUTSIDE	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	VAPORIZER EQUIPMENT	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	WASTE WATER TREATMENT SYSTEM	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	Water Meter and Supply System	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	FIRE FIGHTING EQUIPMENT	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	FUEL HANDLING ACCESORIES	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	HEATING & VENTILATING EQUIP PORT UN	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	HOUSE SERVICE COMPRESSED AIR SYSTEM	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	INTRA-PLANT COMMUNICATION SYSTEM	5360-Narragansett Electric and Gas
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	MACHINE POWER TOOLS	5360-Narragansett Electric and Gas

Utility Account Description	Segment	utility_account_id	retire_unit	company
36100-RIELEC-STRUCT & IMPROVEMENTS	Electric	3610012	Station Maintenance Equipment	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	Non-unitized	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	CONDUIT	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	FENCE	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	FOUNDATION	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	CONDUCTOR	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	INSTRUMENT TRANSFORMER	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	POLE	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	BATTERY BANK	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	BUS INSULATOR	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	TONE EQUIPMENT ISOLATING EQUIPMENT	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	TONE EQUIPMENT TRANSCEIVERS	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	GROUNDING GRID	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	CIRCUIT BREAKER	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	CIRCUIT BREAKER INSTALLATION	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	CABINETS OTHER THAN RELAY	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	DISCONNECT, AIR BREAK, LOADBREAK SW	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	SURGE ARRESTERS	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	RELAY PANEL	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	RELAY PANEL RELAYS & OTHER	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	CAPACITOR BANK	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	POWER TRANSFORMERS	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	RECLOSER INSTALLATION	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	ALARM OR SIGNAL SYSTEM	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	ALARM SYSTEM (ALL)	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	BILCO DOOR	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	BINS BUNKERS SHELVING	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	BOILER STEAM	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	BUILDINGS	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	CABLE/CONDUIT (1000 FT)	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	CABLE/CONDUIT (500 FT)	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	COMMUNICATION SYSTEM INTRA-SITE	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	CORROSION CONTROL	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	CRANES & HOISTING EQUIPMENT	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	DRAINAGE SYSTEM - OUTSIDE	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	Elevators, Cranes, Etc.	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	EROSION PROTECTION	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	FIRE PROTECTION SYSTEM-OUTSIDE	5360-Narragansett Electric and Gas

Utility Account Description	Segment	utility_account_id	retire_unit	company
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	GAS LEAKAGE DETECTOR SYSTEM	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	GAS MAIN	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	HEATING SYSTEM	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	HOLDING PONDS	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	HVAC	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	HVAC SYSTEM INTRA-SITE	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	Intrasite Communication System	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	LEASE STRUCTURE	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	LEASEHOLD IMPROVEMENT	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	MINOR BLDG & STRUCTURE	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	PROPANE STORAGE	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	RIP RAP BREAKWATER	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	ROOF	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	SECURITY GUARD BOOTH	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	SECURITY SYSTEM	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	STRUCTURAL FACILITIES	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	STRUCTURE / IMPROVEMENT	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	TRACK SYS-EXCEPT THOSE IN PLT EQUIP	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	Tunnels Intake and Discharge	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	TUNNELS-OUTSIDE	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	VAPORIZER EQUIPMENT	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	WASTE WATER TREATMENT SYSTEM	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	Water Meter and Supply System	5360-Narragansett Electric and Gas
36200-FRTRAN-STATION EQUIPMENT	Electric	3620002	IPT BREAKER CAPABILITY	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	Non-unitized	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	Non-Utility Property - Land	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	BATTERY EYEWASH STATION	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	CONDUIT	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	CAP CONTROL, SURGE CAPACITORS ALL T	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	FENCE	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	FOUNDATION	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	BIRD PROTECTION	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	RETAINING WALL	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	BUILDING HEATING/COOLING SYSTEM	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	Piping	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	GENERATOR	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	CONDUCTOR	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	INSTRUMENT TRANSFORMER	5360-Narragansett Electric and Gas

Utility Account Description	Segment	utility_account_id	retire_unit	company
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	POLE	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	TRANSFER SWITCH	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	SWITCHGEAR	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	PANELBOARDS	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	STATION SERVICE TRANSFORMER	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	BATTERY BANK	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	DC POWER PANEL	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	BATTERY CHARGER	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	BUS INSULATOR	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	CABLE	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	POWER LINE CARRIER EQUIP. CABINETRY	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	PWR LINE EQUIP.LINE TUNING UNITS	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	POWER LINE CARRIER EQUIP. TRAPS	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	TONE EQUIPMENT ISOLATING EQUIPMENT	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	TONE EQUIPMENT TRANSCEIVERS	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	GROUNDING GRID	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	GROUNDING CONDUCTOR	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	CIRCUIT BREAKER	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	CIRCUIT BREAKER INSTALLATION	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	CABINETS OTHER THAN RELAY	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	BUSHING/BUSHING POTENTIAL DEVICE	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	CIRCUIT SWITCHERS	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	MOTOR MECHANISM	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	DISCONNECT, AIR BREAK, LOADBREAK SW	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	TERMINATOR	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	NEUTRAL RESISTOR	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	SURGE ARRESTERS	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	POWER FUSE	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	RECLOSERS	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	MONITOR & ANNUNCIATOR EQUIPMENT	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	RELAY PANEL	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	RELAY PANEL CABINET	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	RELAY PANEL RELAYS & OTHER	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	DUCTBANK MANHOLES/HANDHOLES	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	DUCTBANK PRECAST TRENCH	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	CAPACITOR BANK	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	REACTOR	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	STATIC VAR COMPENSATOR CAPACITOR	5360-Narragansett Electric and Gas

Utility Account Description	Segment	utility_account_id	retire_unit	company
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	STATIC VAR COMPNSATR CONTRL DEVICE	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	STATIC VAR COMPENSATOR REACTOR	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	STATIC VAR COMPENSATOR THYRISTOR	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	YARD LIGHTING	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	OTHER ENCLOSURE	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	POWER TRANSFORMERS	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	PWR TRANSFORM FREE STANDING COOLER	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	VOLTAGE REGULATOR	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	OIL CONTAINMENT SYSTEM	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	RTU - ALARM SYSTEM	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	ROADS	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	POWER TRANSFORMER INSTALLATION	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	RECLOSER INSTALLATION	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	VOLTAGE REGULATOR INSTALLATION	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	PUMPS WITH MOTORS/COMPRESSORS	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	HOISTS	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	EUA CONVERSION ASSETS	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	TEST RU FOR TEST CONVERSION ONLY	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	ALARM OR SIGNAL SYSTEM	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	ALARM SYSTEM (ALL)	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	YARD GRADING OR SURFACING	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	WALKWAY OR DRIVEWAY	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	Wire & Cable	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	BILCO DOOR	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	BINS BUNKERS SHELVING	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	BOILER STEAM	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	BUILDINGS	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	CABLE/CONDUIT (1000 FT)	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	CABLE/CONDUIT (500 FT)	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	COMMUNICATION SYSTEM INTRA-SITE	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	CORROSION CONTROL	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	CRANES & HOISTING EQUIPMENT	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	DRAINAGE SYSTEM - OUTSIDE	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	Elevators, Cranes, Etc.	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	EROSION PROTECTION	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	FIRE PROTECTION SYSTEM-OUTSIDE	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	GAS LEAKAGE DETECTOR SYSTEM	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	GAS MAIN	5360-Narragansett Electric and Gas

Utility Account Description	Segment	utility_account_id	retire_unit	company
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	HEATING SYSTEM	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	HOLDING PONDS	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	HVAC	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	HVAC SYSTEM INTRA-SITE	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	Intrasite Communication System	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	LEASE STRUCTURE	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	LEASEHOLD IMPROVEMENT	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	MINOR BLDG & STRUCTURE	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	PROPANE STORAGE	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	RIP RAP BREAKWATER	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	ROOF	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	SECURITY GUARD BOOTH	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	SECURITY SYSTEM	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	STRUCTURAL FACILITIES	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	STRUCTURE / IMPROVEMENT	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	TRACK SYS-EXCEPT THOSE IN PLT EQUIP	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	Tunnels Intake and Discharge	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	TUNNELS-OUTSIDE	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	VAPORIZER EQUIPMENT	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	WASTE WATER TREATMENT SYSTEM	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	Water Meter and Supply System	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	GENERATOR	5360-Narragansett Electric and Gas
36200-RIELEC-STATION EQUIPMENT	Electric	3620012	IPT BREAKER CAPABILITY	5360-Narragansett Electric and Gas
36210-RIELEC-STATION EQUIP POLLUTIO	Electric	3621012	BUILDING HEATING/COOLING SYSTEM	5360-Narragansett Electric and Gas
36255-FRELEC-STATION EQUIPMENT EMS	Electric	3625501	Non-unitized	5360-Narragansett Electric and Gas
36400-FRTRAN-POLES,TOWERS AND FIXTU	Electric	3640002	Non-unitized	5360-Narragansett Electric and Gas
36400-FRTRAN-POLES,TOWERS AND FIXTU	Electric	3640002	POLE, METAL, 30' & UNDER, JO	5360-Narragansett Electric and Gas
36400-FRTRAN-POLES,TOWERS AND FIXTU	Electric	3640002	POLE, WOOD, 30' & UNDER, JO	5360-Narragansett Electric and Gas
36400-FRTRAN-POLES,TOWERS AND FIXTU	Electric	3640002	POLE, WOOD, 30' & UNDER, SO	5360-Narragansett Electric and Gas
36400-FRTRAN-POLES,TOWERS AND FIXTU	Electric	3640002	POLE, WOOD, 31' - 40', SO	5360-Narragansett Electric and Gas
36400-FRTRAN-POLES,TOWERS AND FIXTU	Electric	3640002	POLE, WOOD, 51' - 60', SO	5360-Narragansett Electric and Gas
36400-FRTRAN-POLES,TOWERS AND FIXTU	Electric	3640002	GUY Jointly Owned	5360-Narragansett Electric and Gas
36400-FRTRAN-POLES,TOWERS AND FIXTU	Electric	3640002	PLATFORM/SHED	5360-Narragansett Electric and Gas
36400-FRTRAN-POLES,TOWERS AND FIXTU	Electric	3640002	BIRD PROTECTION	5360-Narragansett Electric and Gas
36400-RIELEC-POLES,TOWERS AND FIXTU	Electric	3640012	Non-unitized	5360-Narragansett Electric and Gas
36400-RIELEC-POLES,TOWERS AND FIXTU	Electric	3640012	POLE, METAL, 30' & UNDER, JO	5360-Narragansett Electric and Gas
36400-RIELEC-POLES,TOWERS AND FIXTU	Electric	3640012	POLE, METAL, 30' & UNDER, SO	5360-Narragansett Electric and Gas
36400-RIELEC-POLES,TOWERS AND FIXTU	Electric	3640012	POLE, METAL, 31' - 40', JO	5360-Narragansett Electric and Gas

Utility Account Description	Segment	utility_account_id	retire_unit	company
36400-RIELEC-POLES,TOWERS AND FIXTU	Electric	3640012	POLE, METAL, 51' - 60', JO	5360-Narragansett Electric and Gas
36400-RIELEC-POLES,TOWERS AND FIXTU	Electric	3640012	POLE, METAL, 51' - 60', SO	5360-Narragansett Electric and Gas
36400-RIELEC-POLES,TOWERS AND FIXTU	Electric	3640012	POLE, METAL, 61' - 70', JO	5360-Narragansett Electric and Gas
36400-RIELEC-POLES,TOWERS AND FIXTU	Electric	3640012	POLE, METAL, 61' - 70', SO	5360-Narragansett Electric and Gas
36400-RIELEC-POLES,TOWERS AND FIXTU	Electric	3640012	POLE, METAL, 71' - 80', JO	5360-Narragansett Electric and Gas
36400-RIELEC-POLES,TOWERS AND FIXTU	Electric	3640012	POLE, METAL, 71' - 80', SO	5360-Narragansett Electric and Gas
36400-RIELEC-POLES,TOWERS AND FIXTU	Electric	3640012	POLE, METAL, 81' - 90', SO	5360-Narragansett Electric and Gas
36400-RIELEC-POLES,TOWERS AND FIXTU	Electric	3640012	POLE, METAL, 121' - 130', SO	5360-Narragansett Electric and Gas
36400-RIELEC-POLES,TOWERS AND FIXTU	Electric	3640012	POLE, WOOD, 30' & UNDER, JO	5360-Narragansett Electric and Gas
36400-RIELEC-POLES,TOWERS AND FIXTU	Electric	3640012	POLE, WOOD, 30' & UNDER, SO	5360-Narragansett Electric and Gas
36400-RIELEC-POLES,TOWERS AND FIXTU	Electric	3640012	POLE, WOOD, 31' - 40', JO	5360-Narragansett Electric and Gas
36400-RIELEC-POLES,TOWERS AND FIXTU	Electric	3640012	POLE, WOOD, 31' - 40', SO	5360-Narragansett Electric and Gas
36400-RIELEC-POLES,TOWERS AND FIXTU	Electric	3640012	POLE, WOOD, 41' - 50', JO	5360-Narragansett Electric and Gas
36400-RIELEC-POLES,TOWERS AND FIXTU	Electric	3640012	POLE, WOOD, 41' - 50', SO	5360-Narragansett Electric and Gas
36400-RIELEC-POLES,TOWERS AND FIXTU	Electric	3640012	POLE, WOOD, 51' - 60', JO	5360-Narragansett Electric and Gas
36400-RIELEC-POLES,TOWERS AND FIXTU	Electric	3640012	POLE, WOOD, 51' - 60', SO	5360-Narragansett Electric and Gas
36400-RIELEC-POLES,TOWERS AND FIXTU	Electric	3640012	POLE, WOOD, 61' - 70', JO	5360-Narragansett Electric and Gas
36400-RIELEC-POLES,TOWERS AND FIXTU	Electric	3640012	POLE, WOOD, 61' - 70', SO	5360-Narragansett Electric and Gas
36400-RIELEC-POLES,TOWERS AND FIXTU	Electric	3640012	POLE, WOOD, 71' - 80', SO	5360-Narragansett Electric and Gas
36400-RIELEC-POLES,TOWERS AND FIXTU	Electric	3640012	POLE, WOOD, 81' - 90', SO	5360-Narragansett Electric and Gas
36400-RIELEC-POLES,TOWERS AND FIXTU	Electric	3640012	POLE, FBRGLASS, 31' - 40', JO	5360-Narragansett Electric and Gas
36400-RIELEC-POLES,TOWERS AND FIXTU	Electric	3640012	GUYS ALL TYPES	5360-Narragansett Electric and Gas
36400-RIELEC-POLES,TOWERS AND FIXTU	Electric	3640012	ANCHORS SOLEY OWNED	5360-Narragansett Electric and Gas
36400-RIELEC-POLES,TOWERS AND FIXTU	Electric	3640012	ANCHORS JOINTLY OWNED	5360-Narragansett Electric and Gas
36400-RIELEC-POLES,TOWERS AND FIXTU	Electric	3640012	POLE TOP PIN	5360-Narragansett Electric and Gas
36400-RIELEC-POLES,TOWERS AND FIXTU	Electric	3640012	SECONDARY RACK	5360-Narragansett Electric and Gas
36400-RIELEC-POLES,TOWERS AND FIXTU	Electric	3640012	TRANSFORMER CLUSTER MOUNT	5360-Narragansett Electric and Gas
36400-RIELEC-POLES,TOWERS AND FIXTU	Electric	3640012	TOWER, METAL, 0' - 50'	5360-Narragansett Electric and Gas
36400-RIELEC-POLES,TOWERS AND FIXTU	Electric	3640012	TOWER, METAL, 51' - 100'	5360-Narragansett Electric and Gas
36400-RIELEC-POLES,TOWERS AND FIXTU	Electric	3640012	PLATFORM/SHED	5360-Narragansett Electric and Gas
36400-RIELEC-POLES,TOWERS AND FIXTU	Electric	3640012	CROSSARM, METAL	5360-Narragansett Electric and Gas
36400-RIELEC-POLES,TOWERS AND FIXTU	Electric	3640012	CROSSARM, WOOD	5360-Narragansett Electric and Gas
36400-RIELEC-POLES,TOWERS AND FIXTU	Electric	3640012	ROAD, 364 ACCOUNT	5360-Narragansett Electric and Gas
36400-RIELEC-POLES,TOWERS AND FIXTU	Electric	3640012	BIRD PROTECTION	5360-Narragansett Electric and Gas
36400-RIELEC-POLES,TOWERS AND FIXTU	Electric	3640012	EUA CONVERSION ASSETS	5360-Narragansett Electric and Gas
36400-RIELEC-POLES,TOWERS AND FIXTU	Electric	3640012	CROSSARM, FIBREGLASS	5360-Narragansett Electric and Gas
36500-FRTRAN-OVERHEAD CONDUCTORS AN	Electric	3650002	Non-unitized	5360-Narragansett Electric and Gas
36500-FRTRAN-OVERHEAD CONDUCTORS AN	Electric	3650002	AERIAL CABLE, 1/C, < 1/0	5360-Narragansett Electric and Gas

Utility Account Description	Segment	utility_account_id	retire_unit	company
36500-FRTRAN-OVERHEAD CONDUCTORS AN	Electric	3650002	COND, BARE OR CVRD, < 1/0	5360-Narragansett Electric and Gas
36500-FRTRAN-OVERHEAD CONDUCTORS AN	Electric	3650002	COND, BARE OR CVRD, 1/0	5360-Narragansett Electric and Gas
36500-FRTRAN-OVERHEAD CONDUCTORS AN	Electric	3650002	COND, BARE OR CVRD, > 2/0 - 4/0	5360-Narragansett Electric and Gas
36500-FRTRAN-OVERHEAD CONDUCTORS AN	Electric	3650002	COND, BARE OR CVRD, > 4/0 - 336	5360-Narragansett Electric and Gas
36500-FRTRAN-OVERHEAD CONDUCTORS AN	Electric	3650002	COND, BARE OR CVRD, > 336 - 477	5360-Narragansett Electric and Gas
36500-FRTRAN-OVERHEAD CONDUCTORS AN	Electric	3650002	COND, BARE OR CVRD, > 636 - 795	5360-Narragansett Electric and Gas
36500-FRTRAN-OVERHEAD CONDUCTORS AN	Electric	3650002	COND, SECNDRY CBL, 3/C, < 1/0	5360-Narragansett Electric and Gas
36500-FRTRAN-OVERHEAD CONDUCTORS AN	Electric	3650002	COND, SECNDRY CBL, 3/C, 1/0	5360-Narragansett Electric and Gas
36500-FRTRAN-OVERHEAD CONDUCTORS AN	Electric	3650002	COND, SECNDRY CBL, 3/C, > 1/0-4/0	5360-Narragansett Electric and Gas
36500-FRTRAN-OVERHEAD CONDUCTORS AN	Electric	3650002	COND, SECNDRY CBL, 4/C, 1/0	5360-Narragansett Electric and Gas
36500-FRTRAN-OVERHEAD CONDUCTORS AN	Electric	3650002	SPACER CABLE, 1/C, 1/0	5360-Narragansett Electric and Gas
36500-FRTRAN-OVERHEAD CONDUCTORS AN	Electric	3650002	SPACER CABLE, 1/C, 336	5360-Narragansett Electric and Gas
36500-FRTRAN-OVERHEAD CONDUCTORS AN	Electric	3650002	SWITCH, AIRBREAK	5360-Narragansett Electric and Gas
36500-FRTRAN-OVERHEAD CONDUCTORS AN	Electric	3650002	SWITCH, DISCONNECT	5360-Narragansett Electric and Gas
36500-FRTRAN-OVERHEAD CONDUCTORS AN	Electric	3650002	SWITCH, NON RCLSNG, 1 OR 3 PH	5360-Narragansett Electric and Gas
36500-FRTRAN-OVERHEAD CONDUCTORS AN	Electric	3650002	CUTOUT, EXPULSION	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	Non-unitized	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	INSULATORS, ALL TYPES	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	FAULT INDICATORS, ALL TYPES	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	AERIAL CABLE, 1/C, < 1/0	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	AERIAL CABLE, 1/C, 1/0	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	AERIAL CABLE, 1/C, > 1/0 - 4/0	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	AERIAL CABLE, 1/C, > 4/0 - 477	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	AERIAL CABLE, 1/C, > 477 - 795	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	AERIAL CABLE, 2/C, ALL SIZES	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	AERIAL CABLE, 3/C, < 1/0	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	AERIAL CABLE, 3/C, 1/0	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	AERIAL CABLE, 4/C, < 1/0	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	AERIAL CABLE, 4/C, 1/0	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	COND, BARE OR CVRD, < 1/0	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	COND, BARE OR CVRD, 1/0	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	COND, BARE OR CVRD, 2/0	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	COND, BARE OR CVRD, > 2/0 - 4/0	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	COND, BARE OR CVRD, > 4/0 - 336	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	COND, BARE OR CVRD, > 336 - 477	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	COND, BARE OR CVRD, > 477 - 636	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	COND, BARE OR CVRD, > 636 - 795	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	COND, BARE OR CVRD, > 795 - 1113	5360-Narragansett Electric and Gas

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36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	COND, BARE OR CVRD, > 1113 - 1590	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	COND, SECNDRY CBL, 2/C, ALL SIZES	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	COND, SECNDRY CBL, 3/C, < 1/0	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	COND, SECNDRY CBL, 3/C, 1/0	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	COND, SECNDRY CBL, 3/C, > 1/0-4/0	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	COND, SECNDRY CBL, 3/C, > 4/0	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	COND, SECNDRY CBL, 4/C, < 1/0	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	COND, SECNDRY CBL, 4/C, 1/0	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	COND, SECNDRY CBL, 4/C, > 1/0-4/0	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	COND, SECNDRY CBL, 4/C, > 4/0	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	SPACER CABLE, 1/C, 1/0	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	SPACER CABLE, 1/C, 4/0	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	SPACER CABLE, 1/C, 336	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	SPACER CABLE, 1/C, 477	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	SPACER CABLE, 1/C, 795	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	GROUND, EQUIPMENT	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	LIGHTNING ARRESTER	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	POTHEAD/TERMINATOR	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	SWITCH, AIRBREAK	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	SWITCH, DISCONNECT	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	SWITCH, NON RCLSNG, 1 OR 3 PH	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	SWITCH, LOADBREAK	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	SWITCH, AUTO RCLSNG, 3 PH	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	SWITCH, AUTO RCLSNG, 1 PH	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	CUTOUT, EXPULSION	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	CUTOUT, OIL FUSED	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	Conversion-OH Conductor	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	EUA CONVERSION ASSETS	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	AERIAL CABLE, 3/C 4/0	5360-Narragansett Electric and Gas
36500-RIELEC-OVERHEAD CONDUCTORS AN	Electric	3650012	Voltage Current Sensors OH	5360-Narragansett Electric and Gas
36503-RIELEC-OVERHEAD COND/TELECOM	Electric	3650312	ANTENNA/ANTENNA MAST	5360-Narragansett Electric and Gas
36503-RIELEC-OVERHEAD COND/TELECOM	Electric	3650312	FIXED RADIO EQUIP - RF LINKS	5360-Narragansett Electric and Gas
36610-FRTRAN-UNDERGROUND MANHOLES A	Electric	3661002	Non-unitized	5360-Narragansett Electric and Gas
36610-RIELEC-UNDERGROUND MANHOLES A	Electric	3661012	Non-unitized	5360-Narragansett Electric and Gas
36610-RIELEC-UNDERGROUND MANHOLES A	Electric	3661012	HANDHOLE, 0 - 400 CF	5360-Narragansett Electric and Gas
36610-RIELEC-UNDERGROUND MANHOLES A	Electric	3661012	MANHOLE, 401 - 3000 CF	5360-Narragansett Electric and Gas
36610-RIELEC-UNDERGROUND MANHOLES A	Electric	3661012	MANHOLE/VLT VENT SYSTEM	5360-Narragansett Electric and Gas
36610-RIELEC-UNDERGROUND MANHOLES A	Electric	3661012	NTWRK VLT	5360-Narragansett Electric and Gas

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36610-RIELEC-UNDERGROUND MANHOLES A	Electric	3661012	EUA CONVERSION ASSETS	5360-Narragansett Electric and Gas
36620-FRTRAN-UNDERGROUND CONDUIT	Electric	3662002	Non-unitized	5360-Narragansett Electric and Gas
36620-FRTRAN-UNDERGROUND CONDUIT	Electric	3662002	CONDUIT	5360-Narragansett Electric and Gas
36620-RIELEC-UNDERGROUND CONDUIT	Electric	3662012	Non-unitized	5360-Narragansett Electric and Gas
36620-RIELEC-UNDERGROUND CONDUIT	Electric	3662012	CONDUIT	5360-Narragansett Electric and Gas
36710-FRTRAN-UNDERGROUND CONDUCTORS	Electric	3671002	Non-unitized	5360-Narragansett Electric and Gas
36710-FRTRAN-UNDERGROUND CONDUCTORS	Electric	3671002	CABLE, NONMTL CVRD, 1/C, > 750-1000	5360-Narragansett Electric and Gas
36710-FRTRAN-UNDERGROUND CONDUCTORS	Electric	3671002	CABLE, NONMTL CVRD, 3/C, > 750-1000	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	Non-unitized	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	FAULT INDICATORS, ALL TYPES	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CABLE, LEAD CVRD, 1/C, < 1/0	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CABLE, LEAD CVRD, 1/C, 1/0	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CABLE, LEAD CVRD, 1/C, > 1/0 - 4/0	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CABLE, LEAD CVRD, 1/C, > 4/0-350	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CABLE, LEAD CVRD, 1/C, > 350-500	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CABLE, LEAD CVRD, 1/C, > 500-750	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CABLE, LEAD CVRD, 1/C, > 750-1000	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CABLE, LEAD CVRD, 2/C, < 1/0	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CABLE, LEAD CVRD, 3/C, < 1/0	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CABLE, LEAD CVRD, 3/C, 1/0	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CABLE, LEAD CVRD, 3/C, > 1/0-4/0	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CABLE, LEAD CVRD, 3/C, > 4/0-350	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CABLE, LEAD CVRD, 3/C, > 350-500	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CABLE, NONMTL CVRD, 1/C, > #2-1/0	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CABLE, NONMTL CVRD, 1/C, > 1/0-4/0	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CABLE, NONMTL CVRD, 1/C, > 4/0-350	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CABLE, NONMTL CVRD, 1/C, > 350-500	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CABLE, NONMTL CVRD, 1/C, > 500-750	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CABLE, NONMTL CVRD, 1/C, > 750-1000	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CABLE, NONMTL CVRD, 1/C, > 1500	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CABLE, NONMTL CVRD, 2/C, < 1/0	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CABLE, NONMTL CVRD, 3/C, < 1/0	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CABLE, NONMTL CVRD, 3/C, 1/0	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CABLE, NONMTL CVRD, 3/C, > 1/0-4/0	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CABLE, NONMTL CVRD, 3/C, > 4/0-350	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CABLE, NONMTL CVRD, 3/C, > 350-500	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CABLE, NONMTL CVRD, 3/C, > 500-750	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CABLE, NONMTL CVRD, 3/C, > 750-1000	5360-Narragansett Electric and Gas

Utility Account Description	Segment	utility_account_id	retire_unit	company
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CABLE, SUBMRN, 3/C, < 1/0	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CABLE, SUBMRN, 3/C, 1/0	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CABLE, SUBMRN, 3/C, > 1/0 - 4/0	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CABLE, SUBMRN, 3/C, > 4/0 - 350	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CABLE, SUBMRN, 3/C, > 350 - 500	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CABLE, LEAD CVRD, OIL,1/C,350-500	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	GROUND, EQUIPMENT	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	LIGHTNING ARRESTER	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	POTHEAD/TERMINATOR	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	SWITCH, DISCONNECT	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	SWITCH, NON RCLSNG, 1 OR 3 PH	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CATHODIC PROTECTION/ANODE SYSTEM	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	SWITCH, AUTO RCLSNG, 3 PH	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CABLE, NONMTL CVRD, 1/C, < #2	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CABLE, NONMTL CVRD, 1/C, #2	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CABLE, NONMTL CVRD, 2/C, 1/0	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CUTOUT, EXPULSION	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CUTOUT, OIL FUSED	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	SWTCHGR, PADMNT OR SUBSURFACE	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	URD SWITCHING PEDESTAL, PADMNT	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CABLE, NONMTL CVRD, 1/C,> 1000-1500	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	UG CABLE CURE	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	EUA CONVERSION ASSETS	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	ANTENNA/ANTENNA MAST	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	FIXED RADIO EQUIP - RF LINKS	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CABLE NONMTL CVRD U.G.SEC.QUAD 4/C	5360-Narragansett Electric and Gas
36710-RIELEC-UNDERGROUND CONDUCTORS	Electric	3671012	CABLE LEAD CVRD U.G.SEC.QUAD 4/C	5360-Narragansett Electric and Gas
36810-RIELEC-TRANSFORMER STATIONS	Electric	3681012	Non-unitized	5360-Narragansett Electric and Gas
36810-RIELEC-TRANSFORMER STATIONS	Electric	3681012	CABLE, NONMTL CVRD, 1/C, > #2-1/0	5360-Narragansett Electric and Gas
36810-RIELEC-TRANSFORMER STATIONS	Electric	3681012	CABLE, NONMTL CVRD, 1/C, > 1/0-4/0	5360-Narragansett Electric and Gas
36810-RIELEC-TRANSFORMER STATIONS	Electric	3681012	CABLE, NONMTL CVRD, 1/C, > 4/0-350	5360-Narragansett Electric and Gas
36810-RIELEC-TRANSFORMER STATIONS	Electric	3681012	CABLE, NONMTL CVRD, 1/C, > 350-500	5360-Narragansett Electric and Gas
36810-RIELEC-TRANSFORMER STATIONS	Electric	3681012	CABLE, NONMTL CVRD, 1/C, > 500-750	5360-Narragansett Electric and Gas
36810-RIELEC-TRANSFORMER STATIONS	Electric	3681012	CABLE, NONMTL CVRD, 1/C, > 750-1000	5360-Narragansett Electric and Gas
36810-RIELEC-TRANSFORMER STATIONS	Electric	3681012	CABLE, NONMTL CVRD, 1/C, > 1500	5360-Narragansett Electric and Gas
36810-RIELEC-TRANSFORMER STATIONS	Electric	3681012	NTWRK PROTECTOR, < 1000 A	5360-Narragansett Electric and Gas
36810-RIELEC-TRANSFORMER STATIONS	Electric	3681012	NTWRK PROTECTOR, > 1000 - 1200 A	5360-Narragansett Electric and Gas
36810-RIELEC-TRANSFORMER STATIONS	Electric	3681012	NTWRK PROTECTOR, > 1200 - 1600 A	5360-Narragansett Electric and Gas

Utility Account Description	Segment	utility_account_id	retire_unit	company
36810-RIELEC-TRANSFORMER STATIONS	Electric	3681012	NTWRK PROTECTOR, > 1600 - 1875 A	5360-Narragansett Electric and Gas
36810-RIELEC-TRANSFORMER STATIONS	Electric	3681012	NTWRK PROTECTOR, > 1875 - 2000 A	5360-Narragansett Electric and Gas
36810-RIELEC-TRANSFORMER STATIONS	Electric	3681012	NTWRK PROTECTOR, > 2000 - 2500 A	5360-Narragansett Electric and Gas
36810-RIELEC-TRANSFORMER STATIONS	Electric	3681012	NTWRK PROTECTOR, > 2500 - 2825 A	5360-Narragansett Electric and Gas
36810-RIELEC-TRANSFORMER STATIONS	Electric	3681012	NTWRK PROTECTOR, > 2825 - 3000 A	5360-Narragansett Electric and Gas
36810-RIELEC-TRANSFORMER STATIONS	Electric	3681012	NTWRK PROTECTOR, > 3000 - 3500 A	5360-Narragansett Electric and Gas
36810-RIELEC-TRANSFORMER STATIONS	Electric	3681012	NTWRK VLT, AMP TRAPS	5360-Narragansett Electric and Gas
36810-RIELEC-TRANSFORMER STATIONS	Electric	3681012	NTWRK VLT, BUS & BUS SUPPORTS	5360-Narragansett Electric and Gas
36810-RIELEC-TRANSFORMER STATIONS	Electric	3681012	NTWRK VLT, RELAYS & CONTROLS	5360-Narragansett Electric and Gas
36810-RIELEC-TRANSFORMER STATIONS	Electric	3681012	TRNFMR, NTWRK, 3 PH, < 300 KVA	5360-Narragansett Electric and Gas
36810-RIELEC-TRANSFORMER STATIONS	Electric	3681012	TRNFMR, NTWRK, 3 PH, 300 KVA	5360-Narragansett Electric and Gas
36810-RIELEC-TRANSFORMER STATIONS	Electric	3681012	TRNFMR, NTWRK, 3 PH, >300 - 500 KVA	5360-Narragansett Electric and Gas
36810-RIELEC-TRANSFORMER STATIONS	Electric	3681012	TRNFMR, NTWRK, 3 PH, >500 - 750 KVA	5360-Narragansett Electric and Gas
36810-RIELEC-TRANSFORMER STATIONS	Electric	3681012	TRNFMR, NTWRK, 3 PH, >750-1000 KVA	5360-Narragansett Electric and Gas
36810-RIELEC-TRANSFORMER STATIONS	Electric	3681012	TRNFMR, NTWRK, 3 PH, >1000-1500 KVA	5360-Narragansett Electric and Gas
36810-RIELEC-TRANSFORMER STATIONS	Electric	3681012	TRNFMR, NTWRK, 3 PH, > 1500 KVA	5360-Narragansett Electric and Gas
36810-RIELEC-TRANSFORMER STATIONS	Electric	3681012	TRNFMR, OH, 1 PH, > 333 - 500 KVA	5360-Narragansett Electric and Gas
36810-RIELEC-TRANSFORMER STATIONS	Electric	3681012	TRNFMR, OH, 1 PH, > 500 - 1000 KVA	5360-Narragansett Electric and Gas
36810-RIELEC-TRANSFORMER STATIONS	Electric	3681012	CABLE, NONMTL CVRD, 1/C,> 1000-1500	5360-Narragansett Electric and Gas
36810-RIELEC-TRANSFORMER STATIONS	Electric	3681012	PRECAPITALIZED ASSET INSTALLATION	5360-Narragansett Electric and Gas
36820-FRTRAN-LINE TRANSFORMERS BARE	Electric	3682002	TRNFMR, OH, 1 PH, < 15 KVA	5360-Narragansett Electric and Gas
36820-FRTRAN-LINE TRANSFORMERS BARE	Electric	3682002	TRNFMR, OH, 1 PH, > 75 - 100 KVA	5360-Narragansett Electric and Gas
36820-FRTRAN-LINE TRANSFORMERS BARE	Electric	3682002	TRNFMR, PAD, 1 PH, < 25 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	Non-unitized	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	CAPACITOR UNIT, UNDER 25 KVAR	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	CAPACITOR UNIT, 25 - < 50 KVAR	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	CAPACITOR UNIT, 100 - < 150 KVAR	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	CAPACITOR UNIT, 150 - < 200 KVAR	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	CAPACITOR UNIT, 200 - < 300 KVAR	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	CAPACITOR UNIT, 300 - < 400 KVAR	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	CAPACITOR UNIT, 400 & GRTR KVAR	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	CAP CONTROL, SURGE CAPACITORS ALL T	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	NTWRK PROTECTOR, < 1000 A	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, NTWRK, 3 PH, >300 - 500 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, NTWRK, 3 PH, >500 - 750 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, NTWRK, 3 PH, >750-1000 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, NTWRK, 3 PH, >1000-1500 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, NTWRK, 3 PH, > 1500 KVA	5360-Narragansett Electric and Gas

Utility Account Description	Segment	utility_account_id	retire_unit	company
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, OH, 1 PH, < 15 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, OH, 1 PH, 15 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, OH, 1 PH, > 15 - 25 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, OH, 1 PH, > 25 - 50 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, OH, 1 PH, > 50 - 75 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, OH, 1 PH, > 75 - 100 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, OH, 1 PH, > 100 - 167 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, OH, 1 PH, > 167 - 333 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, OH, 1 PH, > 333 - 500 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, OH, 1 PH, > 500 - 1000 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, OH, 3 PH, < 30 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, OH, 3 PH, 30 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, OH, 3 PH, > 30 - 45 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, OH, 3 PH, > 45 - 75 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, OH, 3 PH, > 75 - 100 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, OH, 3 PH, > 100 - 150 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, OH, 3 PH, > 150 - 300 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, OH, 3 PH, > 300 - 750 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, OH, 3 PH, > 750 - 1500 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, OH, 3 PH, > 1500 - 2500 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, PAD, 1 PH, < 25 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, PAD, 1 PH, 25 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, PAD, 1 PH, > 25 - 50 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, PAD, 1 PH, > 50 - 75 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, PAD, 1 PH, > 75 - 100 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, PAD, 1 PH, > 150 - 300 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, PAD, 1 PH, > 300 - 750 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, PAD, 3 PH, 75 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, PAD, 3 PH, > 75 - 150 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, PAD, 3 PH, > 150 - 300 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, PAD, 3 PH, > 300 - 750 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, PAD, 3 PH, > 750 - 1000 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, PAD, 3 PH, >1000 - 1500 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, PAD, 3 PH, >1500 - 2000 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, PAD, 3 PH, >2000 - 2500 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, PAD, 3 PH, > 2500 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, UG, 1 PH, < 15 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, UG, 1 PH, 15 KVA	5360-Narragansett Electric and Gas

Utility Account Description	Segment	utility_account_id	retire_unit	company
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, UG, 1 PH, > 15 - 25 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, UG, 1 PH, > 25 - 50 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, UG, 1 PH, > 50 - 75 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, UG, 1 PH, > 75 - 100 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, UG, 1 PH, > 100 - 167 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, UG, 3 PH, < 75 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, UG, 3 PH, 75 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, UG, 3 PH, > 150 - 300 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	TRNFMR, UG, 3 PH, > 300 - 750 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	VOLTAGE REG, 1 PH, < 100 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	VOLTAGE REG, 1 PH, 100 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	VOLTAGE REG, 1 PH, > 100 - 167 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	VOLTAGE REG, 1 PH, > 167 - 250 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	VOLTAGE REG, 1 PH, > 250 - 333 KVA	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	VOLTAGE REG, 3 PH, ALL SIZES	5360-Narragansett Electric and Gas
36820-RIELEC-LINE TRANSFORMERS BARE	Electric	3682012	UNDERGROUND EUA - TRANSF. ALL VOLTS	5360-Narragansett Electric and Gas
36830-FRTRAN-LINE TRANSFORMERS INST	Electric	3683002	Non-unitized	5360-Narragansett Electric and Gas
36830-FRTRAN-LINE TRANSFORMERS INST	Electric	3683002	GROUND, EQUIPMENT	5360-Narragansett Electric and Gas
36830-FRTRAN-LINE TRANSFORMERS INST	Electric	3683002	CUTOUT, EXPULSION	5360-Narragansett Electric and Gas
36830-FRTRAN-LINE TRANSFORMERS INST	Electric	3683002	PRECAPITALIZED ASSET INSTALLATION	5360-Narragansett Electric and Gas
36830-FRTRAN-LINE TRANSFORMERS INST	Electric	3683002	EUA CONVERSION ASSETS	5360-Narragansett Electric and Gas
36830-RIELEC-LINE TRANSFORMERS INST	Electric	3683012	Non-unitized	5360-Narragansett Electric and Gas
36830-RIELEC-LINE TRANSFORMERS INST	Electric	3683012	CAP CONTROL, SURGE CAPACITORS ALL T	5360-Narragansett Electric and Gas
36830-RIELEC-LINE TRANSFORMERS INST	Electric	3683012	GROUND, EQUIPMENT	5360-Narragansett Electric and Gas
36830-RIELEC-LINE TRANSFORMERS INST	Electric	3683012	LIGHTNING ARRESTER	5360-Narragansett Electric and Gas
36830-RIELEC-LINE TRANSFORMERS INST	Electric	3683012	CUTOUT, EXPULSION	5360-Narragansett Electric and Gas
36830-RIELEC-LINE TRANSFORMERS INST	Electric	3683012	CUTOUT, OIL FUSED	5360-Narragansett Electric and Gas
36830-RIELEC-LINE TRANSFORMERS INST	Electric	3683012	PRECAPITALIZED ASSET INSTALLATION	5360-Narragansett Electric and Gas
36830-RIELEC-LINE TRANSFORMERS INST	Electric	3683012	EUA CONVERSION ASSETS	5360-Narragansett Electric and Gas
36910-RIELEC-OVERHEAD SERVICES	Electric	3691012	Non-unitized	5360-Narragansett Electric and Gas
36910-RIELEC-OVERHEAD SERVICES	Electric	3691012	OVERHEAD SERVICE, ALL TYPES	5360-Narragansett Electric and Gas
36910-RIELEC-OVERHEAD SERVICES	Electric	3691012	EUA CONVERSION ASSETS	5360-Narragansett Electric and Gas
36920-RIELEC-UNDERGROUND SERVICES C	Electric	3692012	Non-unitized	5360-Narragansett Electric and Gas
36920-RIELEC-UNDERGROUND SERVICES C	Electric	3692012	UNDERGROUND SERVICE, CONDUIT	5360-Narragansett Electric and Gas
36921-RIELEC-UNDERGROUND SERVICES C	Electric	3692112	Non-unitized	5360-Narragansett Electric and Gas
36921-RIELEC-UNDERGROUND SERVICES C	Electric	3692112	UNDERGROUND SERVICE, CABLE	5360-Narragansett Electric and Gas
37010-FRTRAN-METERS BARE COST (DOME	Electric	3701002	Non-unitized	5360-Narragansett Electric and Gas
37010-FRTRAN-METERS BARE COST (DOME	Electric	3701002	METERS (EA)	5360-Narragansett Electric and Gas

Utility Account Description	Segment	utility_account_id	retire_unit	company
37010-RIELEC-METERS BARE COST (DOME	Electric	3701012	Non-unitized	5360-Narragansett Electric and Gas
37010-RIELEC-METERS BARE COST (DOME	Electric	3701012	METERS (EA)	5360-Narragansett Electric and Gas
37010-RIELEC-METERS BARE COST (DOME	Electric	3701012	EUA CONVERSION ASSETS	5360-Narragansett Electric and Gas
37020-RIELEC-METERS INSTALL COST (D	Electric	3702012	Non-unitized	5360-Narragansett Electric and Gas
37020-RIELEC-METERS INSTALL COST (D	Electric	3702012	METER INSTALLATION	5360-Narragansett Electric and Gas
37030-FRTRAN-LRG METER INSTALL BARE	Electric	3703002	Non-unitized	5360-Narragansett Electric and Gas
37030-FRTRAN-LRG METER INSTALL BARE	Electric	3703002	METERS (EA)	5360-Narragansett Electric and Gas
37030-RIELEC-LRG METER INSTALL BARE	Electric	3703012	METERS (EA)	5360-Narragansett Electric and Gas
37035-FRTRAN-LRG METERS INSTALL COS	Electric	3703502	METER INSTALLATION	5360-Narragansett Electric and Gas
37035-RIELEC-LRG METERS INSTALL COS	Electric	3703512	Non-unitized	5360-Narragansett Electric and Gas
37035-RIELEC-LRG METERS INSTALL COS	Electric	3703512	METER INSTALLATION	5360-Narragansett Electric and Gas
37100-RIELEC-INSTALLATION ON CUSTOM	Electric	3710012	Non-unitized	5360-Narragansett Electric and Gas
37200-RIELEC-LEASED PROPERTY ON CUS		3720012	WATER HEATERS	5360-Narragansett Electric and Gas
37200-RIELEC-LEASED PROPERTY ON CUS		3720012	Leased LEASE DEFAULT	5360-Narragansett Electric and Gas
37200-RIELEC- Leased prop customer		3720013	Leased LEASE DEFAULT	5360-Narragansett Electric and Gas
37310-RIELEC-OH STEETLIGHTING	Electric	3731012	Non-unitized	5360-Narragansett Electric and Gas
37310-RIELEC-OH STEETLIGHTING	Electric	3731012	POLE, METAL, 30' & UNDER, SO	5360-Narragansett Electric and Gas
37310-RIELEC-OH STEETLIGHTING	Electric	3731012	COND, BARE OR CVRD, < 1/0	5360-Narragansett Electric and Gas
37310-RIELEC-OH STEETLIGHTING	Electric	3731012	COND, BARE OR CVRD, 1/0	5360-Narragansett Electric and Gas
37310-RIELEC-OH STEETLIGHTING	Electric	3731012	COND, SECNDRY CBL, 2/C, ALL SIZES	5360-Narragansett Electric and Gas
37310-RIELEC-OH STEETLIGHTING	Electric	3731012	COND, SECNDRY CBL, 3/C, < 1/0	5360-Narragansett Electric and Gas
37310-RIELEC-OH STEETLIGHTING	Electric	3731012	COND, SECNDRY CBL, 3/C, 1/0	5360-Narragansett Electric and Gas
37310-RIELEC-OH STEETLIGHTING	Electric	3731012	CABLE, LEAD CVRD, 1/C, < 1/0	5360-Narragansett Electric and Gas
37310-RIELEC-OH STEETLIGHTING	Electric	3731012	CABLE, LEAD CVRD, 1/C, 1/0	5360-Narragansett Electric and Gas
37310-RIELEC-OH STEETLIGHTING	Electric	3731012	CABLE, LEAD CVRD, 3/C, 1/0	5360-Narragansett Electric and Gas
37310-RIELEC-OH STEETLIGHTING	Electric	3731012	BRACKET, <= 10'	5360-Narragansett Electric and Gas
37310-RIELEC-OH STEETLIGHTING	Electric	3731012	BRACKET, > 10'	5360-Narragansett Electric and Gas
37310-RIELEC-OH STEETLIGHTING	Electric	3731012	BRACKET, DECOR, <= 10'	5360-Narragansett Electric and Gas
37310-RIELEC-OH STEETLIGHTING	Electric	3731012	CABLE, LEAD CVRD, 2/C, 1/0	5360-Narragansett Electric and Gas
37310-RIELEC-OH STEETLIGHTING	Electric	3731012	HZN, LUM, ROADWAY, LED, ALL SIZES	5360-Narragansett Electric and Gas
37310-RIELEC-OH STEETLIGHTING	Electric	3731012	HZN LUMN, UNDERPASS, HID, ALL SIZES	5360-Narragansett Electric and Gas
37310-RIELEC-OH STEETLIGHTING	Electric	3731012	FLOODLIGHT LUMN, HID, ALL SIZES	5360-Narragansett Electric and Gas
37310-RIELEC-OH STEETLIGHTING	Electric	3731012	T/D LUMN, DEL PARK, ALL TYPE/SIZE	5360-Narragansett Electric and Gas
37310-RIELEC-OH STEETLIGHTING	Electric	3731012	LUMN, INCANDESCENT, ALL TYPE/SIZE	5360-Narragansett Electric and Gas
37310-RIELEC-OH STEETLIGHTING	Electric	3731012	LUMN, MISCELLANEOUS, ALL TYPE/SIZE	5360-Narragansett Electric and Gas
37310-RIELEC-OH STEETLIGHTING	Electric	3731012	SL CONTROL EQUIPMENT	5360-Narragansett Electric and Gas
37310-RIELEC-OH STEETLIGHTING	Electric	3731012	Conversion-OHSL Luminaire	5360-Narragansett Electric and Gas
37320-RIELEC-UG STREETLIGHTING	Electric	3732012	Non-unitized	5360-Narragansett Electric and Gas

Utility Account Description	Segment	utility_account_id	retire_unit	company
37320-RIELEC-UG STREETLIGHTING	Electric	3732012	CABLE, LEAD CVRD, 1/C, < 1/0	5360-Narragansett Electric and Gas
37320-RIELEC-UG STREETLIGHTING	Electric	3732012	CABLE, LEAD CVRD, 1/C, 1/0	5360-Narragansett Electric and Gas
37320-RIELEC-UG STREETLIGHTING	Electric	3732012	CABLE, LEAD CVRD, 3/C, 1/0	5360-Narragansett Electric and Gas
37320-RIELEC-UG STREETLIGHTING	Electric	3732012	CABLE, NONMTL CVRD, 1/C, > #2-1/0	5360-Narragansett Electric and Gas
37320-RIELEC-UG STREETLIGHTING	Electric	3732012	CABLE, NONMTL CVRD, 2/C, < 1/0	5360-Narragansett Electric and Gas
37320-RIELEC-UG STREETLIGHTING	Electric	3732012	CABLE, NONMTL CVRD, 3/C, < 1/0	5360-Narragansett Electric and Gas
37320-RIELEC-UG STREETLIGHTING	Electric	3732012	CONDUIT	5360-Narragansett Electric and Gas
37320-RIELEC-UG STREETLIGHTING	Electric	3732012	HANDHOLE, 0 - 400 CF	5360-Narragansett Electric and Gas
37320-RIELEC-UG STREETLIGHTING	Electric	3732012	FOUNDATIONS, CONC, CAST IN PLACE	5360-Narragansett Electric and Gas
37320-RIELEC-UG STREETLIGHTING	Electric	3732012	BRACKET, <= 10'	5360-Narragansett Electric and Gas
37320-RIELEC-UG STREETLIGHTING	Electric	3732012	CABLE, LEAD CVRD, 2/C, 1/0	5360-Narragansett Electric and Gas
37320-RIELEC-UG STREETLIGHTING	Electric	3732012	HZN, LUM, ROADWAY, LED, ALL SIZES	5360-Narragansett Electric and Gas
37320-RIELEC-UG STREETLIGHTING	Electric	3732012	HZN LUMN, UNDERPASS, HID, ALL SIZES	5360-Narragansett Electric and Gas
37320-RIELEC-UG STREETLIGHTING	Electric	3732012	FLOODLIGHT LUMN, HID, ALL SIZES	5360-Narragansett Electric and Gas
37320-RIELEC-UG STREETLIGHTING	Electric	3732012	P/T LUMN, ASPEN GROVE,ALL TYPE/SIZE	5360-Narragansett Electric and Gas
37320-RIELEC-UG STREETLIGHTING	Electric	3732012	P/T LUMN, CONTEMP, ALL TYPE/SIZE	5360-Narragansett Electric and Gas
37320-RIELEC-UG STREETLIGHTING	Electric	3732012	P/T LUMN, TRADITIONAL,ALL TYPE/SIZE	5360-Narragansett Electric and Gas
37320-RIELEC-UG STREETLIGHTING	Electric	3732012	P/T LUMN, ACORN EDISON, ALL TYPE/SI	5360-Narragansett Electric and Gas
37320-RIELEC-UG STREETLIGHTING	Electric	3732012	P/T LUMN,ACORN WLMSVL,ALL TYPE/SIZE	5360-Narragansett Electric and Gas
37320-RIELEC-UG STREETLIGHTING	Electric	3732012	LUMN, INCANDESCENT, ALL TYPE/SIZE	5360-Narragansett Electric and Gas
37320-RIELEC-UG STREETLIGHTING	Electric	3732012	LUMN, MISCELLANEOUS, ALL TYPE/SIZE	5360-Narragansett Electric and Gas
37320-RIELEC-UG STREETLIGHTING	Electric	3732012	ARM, TRUSS/PENDANT, <= 10'	5360-Narragansett Electric and Gas
37320-RIELEC-UG STREETLIGHTING	Electric	3732012	ARM, DECOR, <= 10'	5360-Narragansett Electric and Gas
37320-RIELEC-UG STREETLIGHTING	Electric	3732012	SHAFT, DAVIT, MTL-AB, >16'	5360-Narragansett Electric and Gas
37320-RIELEC-UG STREETLIGHTING	Electric	3732012	SHAFT, SPECIALTY-AB, >=16'	5360-Narragansett Electric and Gas
37320-RIELEC-UG STREETLIGHTING	Electric	3732012	SHAFT, PT, DE, NONMTL, <=16'	5360-Narragansett Electric and Gas
37320-RIELEC-UG STREETLIGHTING	Electric	3732012	SHAFT, PT, AB, NONMTL, <=16'	5360-Narragansett Electric and Gas
37320-RIELEC-UG STREETLIGHTING	Electric	3732012	SHAFT, PT, DE, MTL, <=16'	5360-Narragansett Electric and Gas
37320-RIELEC-UG STREETLIGHTING	Electric	3732012	SHAFT, PT, AB, MTL, DECOR, <=16'	5360-Narragansett Electric and Gas
37320-RIELEC-UG STREETLIGHTING	Electric	3732012	SHAFT, T/P, AB, NONMTL, >=16'	5360-Narragansett Electric and Gas
37320-RIELEC-UG STREETLIGHTING	Electric	3732012	SHAFT, T/P, AB, MTL, >=10'	5360-Narragansett Electric and Gas
37320-RIELEC-UG STREETLIGHTING	Electric	3732012	SL TRANSFORMER BASE, MTL, ALL TYPES	5360-Narragansett Electric and Gas
37320-RIELEC-UG STREETLIGHTING	Electric	3732012	SL CONTROL EQUIPMENT	5360-Narragansett Electric and Gas
37320-RIELEC-UG STREETLIGHTING	Electric	3732012	CABLE, NONMTL CVRD, 1/C, < #2	5360-Narragansett Electric and Gas
37320-RIELEC-UG STREETLIGHTING	Electric	3732012	CABLE, NONMTL CVRD, 1/C, #2	5360-Narragansett Electric and Gas
37320-RIELEC-UG STREETLIGHTING	Electric	3732012	EUA CONVERSION ASSETS	5360-Narragansett Electric and Gas
37320-RIELEC-UG STREETLIGHTING	Electric	3732012	P/T LUMN, FRANKLIN SQUARE ,ALL TYPE	5360-Narragansett Electric and Gas
37320-RIELEC-UG STREETLIGHTING	Electric	3732012	P/T LUMN,WATERTOW,ALL TYPE/SIZE	5360-Narragansett Electric and Gas

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37320-RIELEC-UG STREETLIGHTING	Electric	3732012	SHAFT ,T/P, DE,CONC,>16'	5360-Narragansett Electric and Gas
37330-RIELEC-LED OH LIGHTING	Electric	3733012	HZN, LUM, ROADWAY, LED, ALL SIZES	5360-Narragansett Electric and Gas
37340-RIELEC-LED LIGHTING	Electric	3734012	HZN, LUM, ROADWAY, LED, ALL SIZES	5360-Narragansett Electric and Gas
38900-FRTRAN-LAND ELEC GENL	Electric	3890002	LAND	5360-Narragansett Electric and Gas
38900-RIELEC-LAND ELEC GENL	Electric	3890012	LAND	5360-Narragansett Electric and Gas
38910-FRTRAN-LAND RGHT & OTHR COST	Electric	3891002	LAND RIGHTS & ADDITIONAL COSTS	5360-Narragansett Electric and Gas
39000-FRTRAN-STRUCT AND IMPROV ELEC	GAS	3900002	Non-unitized	5360-Narragansett Electric and Gas
39000-FRTRAN-STRUCT AND IMPROV ELEC	GAS	3900002	BUILDING & ADDITIONS	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	Non-unitized	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	Non-Utility Property - Land	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	BUILDING & ADDITIONS	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	Permanent Interior Walls	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	Roofing Shingles	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	BUILDING HEATING/COOLING SYSTEM	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	Building Sitework	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	Paving	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	BATTERY CHARGER	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	HOISTS	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	Conversion-UG Cable	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	CEILING	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	ELEVATOR	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	EXTERIOR DOORS & WINDOWS	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	FINISH SYSTEMS - WINDOWS	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	FINISH SYSTEMS - WALLS	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	SPECIAL CONSTRUCTION & EQUIPMENT	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	BUILDING SPECIALTY ELEC SYSTEM	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	BUILDING SANITARY SYSTEM	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	Storm Water Management System	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	LIGHTING & POWER SYSTEM	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	PLUMBING SYSTEM (ALL)	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	FLOOR COVERING	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	BILCO DOOR	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	BINS BUNKERS SHELVING	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	BOILER STEAM	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	BUILDINGS	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	CABLE/CONDUIT (1000 FT)	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	CABLE/CONDUIT (500 FT)	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	COMMUNICATION SYSTEM INTRA-SITE	5360-Narragansett Electric and Gas

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39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	CORROSION CONTROL	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	CRANES & HOISTING EQUIPMENT	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	DRAINAGE SYSTEM - OUTSIDE	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	Elevators, Cranes, Etc.	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	EROSION PROTECTION	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	FIRE PROTECTION SYSTEM-OUTSIDE	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	GAS LEAKAGE DETECTOR SYSTEM	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	GAS MAIN	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	HEATING SYSTEM	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	HOLDING PONDS	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	HVAC	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	HVAC SYSTEM INTRA-SITE	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	Intrasite Communication System	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	LEASE STRUCTURE	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	LEASEHOLD IMPROVEMENT	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	MINOR BLDG & STRUCTURE	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	PROPANE STORAGE	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	RIP RAP BREAKWATER	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	ROOF	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	SECURITY GUARD BOOTH	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	SECURITY SYSTEM	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	STRUCTURAL FACILITIES	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	STRUCTURE / IMPROVEMENT	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	TRACK SYS-EXCEPT THOSE IN PLT EQUIP	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	Tunnels Intake and Discharge	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	TUNNELS-OUTSIDE	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	VAPORIZER EQUIPMENT	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	WASTE WATER TREATMENT SYSTEM	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	Water Meter and Supply System	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	FIRE FIGHTING EQUIPMENT	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	FUEL HANDLING ACCESORIES	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	HEATING & VENTILATING EQUIP PORT UN	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	HOUSE SERVICE COMPRESSED AIR SYSTEM	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	INTRA-PLANT COMMUNICATION SYSTEM	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	MACHINE POWER TOOLS	5360-Narragansett Electric and Gas
39000-RIELEC-STRUCT AND IMPROV ELEC	GAS	3900012	Station Maintenance Equipment	5360-Narragansett Electric and Gas
39001-FRTRAN-STRUCT AND IMPROV ELEC	GAS	3900102	BUILDING & ADDITIONS	5360-Narragansett Electric and Gas
39001-FRTRAN-STRUCT AND IMPROV ELEC	GAS	3900102	Building Power Distrib Syst Plant	5360-Narragansett Electric and Gas

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39001-FRTRAN-STRUCT AND IMPROV ELEC	GAS	3900102	HOISTS	5360-Narragansett Electric and Gas
39001-FRTRAN-STRUCT AND IMPROV ELEC	GAS	3900102	MONO-RAILS	5360-Narragansett Electric and Gas
39001-FRTRAN-STRUCT AND IMPROV ELEC	GAS	3900102	EXTERIOR DOORS & WINDOWS	5360-Narragansett Electric and Gas
39001-FRTRAN-STRUCT AND IMPROV ELEC	GAS	3900102	FINISH SYSTEMS - WINDOWS	5360-Narragansett Electric and Gas
39001-FRTRAN-STRUCT AND IMPROV ELEC	GAS	3900102	FINISH SYSTEMS - WALLS	5360-Narragansett Electric and Gas
39001-FRTRAN-STRUCT AND IMPROV ELEC	GAS	3900102	BUILDING COMMUN & DATA CABLING PLNT	5360-Narragansett Electric and Gas
39001-FRTRAN-STRUCT AND IMPROV ELEC	GAS	3900102	LIGHTING & POWER SYSTEM	5360-Narragansett Electric and Gas
39001-FRTRAN-STRUCT AND IMPROV ELEC	GAS	3900102	FIRE PROTECTION SYSTEM (ALL)	5360-Narragansett Electric and Gas
39001-FRTRAN-STRUCT AND IMPROV ELEC	GAS	3900102	FLOOR COVERING	5360-Narragansett Electric and Gas
39100-FRTRAN-OFFICE FURN &FIXT ELEC	Electric	3910002	GENERAL PLANT < $20,000	5360-Narragansett Electric and Gas
39100-FRTRAN-OFFICE FURN &FIXT ELEC	Electric	3910002	GENERAL PLANT $20,000 OR >	5360-Narragansett Electric and Gas
39100-RIELEC-OFFICE FURN &FIXT ELEC	Electric	3910012	EUA CONVERSION ASSETS	5360-Narragansett Electric and Gas
39100-RIELEC-OFFICE FURN &FIXT ELEC	Electric	3910012	GENERAL PLANT < $20,000	5360-Narragansett Electric and Gas
39110-RIELEC-OTHER OFFICE EQUIPMENT	Electric	3911012	Non-unitized	5360-Narragansett Electric and Gas
39111-RIGAS-EQUIPMENT COMPUTERS	GAS	3911113	LAPTOPS	5360-Narragansett Electric and Gas
39120-RIELEC-OFFICE DATA PROCESSING	Electric	3912012	Non-unitized	5360-Narragansett Electric and Gas
39200-RIELEC- Transportation equipm	GAS	3920002	Leased LEASE DEFAULT	5360-Narragansett Electric and Gas
39200-RIELEC-PASSENGER CARS TRANSP	GAS	3920012	EUA CONVERSION ASSETS	5360-Narragansett Electric and Gas
39200-RIELEC-PASSENGER CARS TRANSP	GAS	3920012	Leased LEASE DEFAULT	5360-Narragansett Electric and Gas
39200-RIELEC- Transportation equipm	GAS	3920013	GENERAL PLANT < $20,000	5360-Narragansett Electric and Gas
39200-RIELEC- Transportation equipm	GAS	3920013	Leased LEASE DEFAULT	5360-Narragansett Electric and Gas
39210-RIELEC-VEHICLES BANKERS	GAS	3921012	Non-unitized	5360-Narragansett Electric and Gas
39210-RIELEC-VEHICLES BANKERS	GAS	3921012	GENERAL PLANT $20,000 OR >	5360-Narragansett Electric and Gas
39300-RIELEC-STORES EQUIPMENT	GAS	3930012	Non-unitized	5360-Narragansett Electric and Gas
39300-RIELEC-STORES EQUIPMENT	GAS	3930012	EUA CONVERSION ASSETS	5360-Narragansett Electric and Gas
39300-RIELEC-STORES EQUIPMENT	GAS	3930012	GENERAL PLANT < $20,000	5360-Narragansett Electric and Gas
39300-RIELEC-STORES EQUIPMENT	GAS	3930012	GENERAL PLANT $20,000 OR >	5360-Narragansett Electric and Gas
39400-FRELEC-SHOP EQUIPMENT	GAS	3940001	Non-unitized	5360-Narragansett Electric and Gas
39400-FRELEC-SHOP EQUIPMENT	GAS	3940001	GENERAL PLANT < $20,000	5360-Narragansett Electric and Gas
39400-FRELEC-SHOP EQUIPMENT	GAS	3940001	GENERAL PLANT $20,000 OR >	5360-Narragansett Electric and Gas
39400-FRTRAN-GENERAL PLANT TOOLS SH	GAS	3940002	Non-unitized	5360-Narragansett Electric and Gas
39400-FRTRAN-GENERAL PLANT TOOLS SH	GAS	3940002	GENERAL PLANT < $20,000	5360-Narragansett Electric and Gas
39400-FRTRAN-GENERAL PLANT TOOLS SH	GAS	3940002	GENERAL PLANT $20,000 OR >	5360-Narragansett Electric and Gas
39400-RIELEC-GENERAL PLANT TOOLS SH	GAS	3940012	Non-unitized	5360-Narragansett Electric and Gas
39400-RIELEC-GENERAL PLANT TOOLS SH	GAS	3940012	EUA CONVERSION ASSETS	5360-Narragansett Electric and Gas
39400-RIELEC-GENERAL PLANT TOOLS SH	GAS	3940012	GENERAL PLANT < $20,000	5360-Narragansett Electric and Gas
39400-RIELEC-GENERAL PLANT TOOLS SH	GAS	3940012	GENERAL PLANT $20,000 OR >	5360-Narragansett Electric and Gas
39500-FRTRAN-GENERAL PLANT LABORATO	GAS	3950002	Non-unitized	5360-Narragansett Electric and Gas

Utility Account Description	Segment	utility_account_id	retire_unit	company
39500-FRTRAN-GENERAL PLANT LABORATO	GAS	3950002	GENERAL PLANT < $20,000	5360-Narragansett Electric and Gas
39500-FRTRAN-GENERAL PLANT LABORATO	GAS	3950002	GENERAL PLANT $20,000 OR >	5360-Narragansett Electric and Gas
39500-RIELEC-GENERAL PLANT LABORATO	GAS	3950012	Non-unitized	5360-Narragansett Electric and Gas
39500-RIELEC-GENERAL PLANT LABORATO	GAS	3950012	EUA CONVERSION ASSETS	5360-Narragansett Electric and Gas
39500-RIELEC-GENERAL PLANT LABORATO	GAS	3950012	GENERAL PLANT < $20,000	5360-Narragansett Electric and Gas
39500-RIELEC-GENERAL PLANT LABORATO	GAS	3950012	GENERAL PLANT $20,000 OR >	5360-Narragansett Electric and Gas
39510-RIELEC-CONSERVATION LAB EQUIP	Electric	3951012	Non-unitized	5360-Narragansett Electric and Gas
39700-FRTRAN-COMM EQUIP AMORTIZED N	GAS	3970002	TOWER	5360-Narragansett Electric and Gas
39700-RIELEC-COMM EQUIP AMORTIZED N	GAS	3970012	ERT DEVICE FOR METER	5360-Narragansett Electric and Gas
39710-FRELEC-COMM EQUIP SITE SPECIF	GAS	3971001	BUILDING COMMUN & DATA CABLING PLNT	5360-Narragansett Electric and Gas
39710-FRELEC-COMM EQUIP SITE SPECIF	GAS	3971001	FIXED RADIO EQUIP - CONTROLLERS	5360-Narragansett Electric and Gas
39710-FRELEC-COMM EQUIP SITE SPECIF	GAS	3971001	FIXED RADIO EQUIP - RF LINKS	5360-Narragansett Electric and Gas
39710-FRTRAN-COMM EQUIP SITE SPECIF	GAS	3971002	Non-unitized	5360-Narragansett Electric and Gas
39710-FRTRAN-COMM EQUIP SITE SPECIF	GAS	3971002	FENCE	5360-Narragansett Electric and Gas
39710-FRTRAN-COMM EQUIP SITE SPECIF	GAS	3971002	LIGHTNING ARRESTER	5360-Narragansett Electric and Gas
39710-FRTRAN-COMM EQUIP SITE SPECIF	GAS	3971002	TRANSFORMERS BY SIZE & KIND	5360-Narragansett Electric and Gas
39710-FRTRAN-COMM EQUIP SITE SPECIF	GAS	3971002	BATTERY CHARGER	5360-Narragansett Electric and Gas
39710-FRTRAN-COMM EQUIP SITE SPECIF	GAS	3971002	CABLE	5360-Narragansett Electric and Gas
39710-FRTRAN-COMM EQUIP SITE SPECIF	GAS	3971002	BUILDING COMMUN & DATA CABLING PLNT	5360-Narragansett Electric and Gas
39710-FRTRAN-COMM EQUIP SITE SPECIF	GAS	3971002	BUILDING SPECIALTY ELEC SYSTEM	5360-Narragansett Electric and Gas
39710-FRTRAN-COMM EQUIP SITE SPECIF	GAS	3971002	POLES ALL SIZES INC.GUY,ANCHOR,XARM	5360-Narragansett Electric and Gas
39710-FRTRAN-COMM EQUIP SITE SPECIF	GAS	3971002	CONDUIT ALL SIZES INC. RISER & HAND	5360-Narragansett Electric and Gas
39710-FRTRAN-COMM EQUIP SITE SPECIF	GAS	3971002	DISCONNECT /CIRCUIT BREAKER SWITCHE	5360-Narragansett Electric and Gas
39710-FRTRAN-COMM EQUIP SITE SPECIF	GAS	3971002	CABINET/PANELBOARD W/DEVICES	5360-Narragansett Electric and Gas
39710-FRTRAN-COMM EQUIP SITE SPECIF	GAS	3971002	POWER OR RINGING CURRENT SUPPLY DEV	5360-Narragansett Electric and Gas
39710-FRTRAN-COMM EQUIP SITE SPECIF	GAS	3971002	REPEATER	5360-Narragansett Electric and Gas
39710-FRTRAN-COMM EQUIP SITE SPECIF	GAS	3971002	BATTERY	5360-Narragansett Electric and Gas
39710-FRTRAN-COMM EQUIP SITE SPECIF	GAS	3971002	STANDBY GENERATOR INC. TANKS	5360-Narragansett Electric and Gas
39710-FRTRAN-COMM EQUIP SITE SPECIF	GAS	3971002	EQUIPMENT HOUSING	5360-Narragansett Electric and Gas
39710-FRTRAN-COMM EQUIP SITE SPECIF	GAS	3971002	YARD GRADING OR SURFACING	5360-Narragansett Electric and Gas
39710-FRTRAN-COMM EQUIP SITE SPECIF	GAS	3971002	WALKWAY OR DRIVEWAY	5360-Narragansett Electric and Gas
39710-FRTRAN-COMM EQUIP SITE SPECIF	GAS	3971002	TOWER	5360-Narragansett Electric and Gas
39710-FRTRAN-COMM EQUIP SITE SPECIF	GAS	3971002	TELEPHONE ANSWERING DEVICE	5360-Narragansett Electric and Gas
39710-FRTRAN-COMM EQUIP SITE SPECIF	GAS	3971002	TRANSMITTER/RECEIVER	5360-Narragansett Electric and Gas
39710-FRTRAN-COMM EQUIP SITE SPECIF	GAS	3971002	REMOTE CONTROL UNIT	5360-Narragansett Electric and Gas
39710-FRTRAN-COMM EQUIP SITE SPECIF	GAS	3971002	ANTENNA/ANTENNA MAST	5360-Narragansett Electric and Gas
39710-FRTRAN-COMM EQUIP SITE SPECIF	GAS	3971002	POWER SUPPLY	5360-Narragansett Electric and Gas
39710-FRTRAN-COMM EQUIP SITE SPECIF	GAS	3971002	MICROWAVE WAVE GUIDE	5360-Narragansett Electric and Gas

Utility Account Description	Segment	utility_account_id	retire_unit	company
39710-FRTRAN-COMM EQUIP SITE SPECIF	GAS	3971002	ALARM CONTROL REMOTE RESPONDER	5360-Narragansett Electric and Gas
39710-FRTRAN-COMM EQUIP SITE SPECIF	GAS	3971002	MULTIPLEX COMMON & INDIVIDUALEQUIP.	5360-Narragansett Electric and Gas
39710-FRTRAN-COMM EQUIP SITE SPECIF	GAS	3971002	POWER SUPPLY LINE TO SITE	5360-Narragansett Electric and Gas
39710-FRTRAN-COMM EQUIP SITE SPECIF	GAS	3971002	JACK FIELD	5360-Narragansett Electric and Gas
39710-FRTRAN-COMM EQUIP SITE SPECIF	GAS	3971002	DEHYDRATOR	5360-Narragansett Electric and Gas
39710-FRTRAN-COMM EQUIP SITE SPECIF	GAS	3971002	MICROWAVE TEST EQUIPMENT	5360-Narragansett Electric and Gas
39710-FRTRAN-COMM EQUIP SITE SPECIF	GAS	3971002	FIBER OPTIC CABLE - ALL SIZES	5360-Narragansett Electric and Gas
39710-FRTRAN-COMM EQUIP SITE SPECIF	GAS	3971002	FIBER OPTIC TERMINAL EQUIPMENT - AL	5360-Narragansett Electric and Gas
39710-FRTRAN-COMM EQUIP SITE SPECIF	GAS	3971002	TELEMETERING EQUIPMENT	5360-Narragansett Electric and Gas
39710-FRTRAN-COMM EQUIP SITE SPECIF	GAS	3971002	NETWORK MICROWAVE EQUIPMENT	5360-Narragansett Electric and Gas
39710-FRTRAN-COMM EQUIP SITE SPECIF	GAS	3971002	FIXED RADIO EQUIP - BASE UNIT	5360-Narragansett Electric and Gas
39710-FRTRAN-COMM EQUIP SITE SPECIF	GAS	3971002	FIXED RADIO EQUIP - COMPUTERS	5360-Narragansett Electric and Gas
39710-FRTRAN-COMM EQUIP SITE SPECIF	GAS	3971002	FIXED RADIO EQUIP - CONTROLLERS	5360-Narragansett Electric and Gas
39710-FRTRAN-COMM EQUIP SITE SPECIF	GAS	3971002	FIXED RADIO EQUIP - RF LINKS	5360-Narragansett Electric and Gas
39710-RIELEC-COMM EQUIP SITE SPECIF	GAS	3971012	Non-unitized	5360-Narragansett Electric and Gas
39710-RIELEC-COMM EQUIP SITE SPECIF	GAS	3971012	Non-Utility Property - Land	5360-Narragansett Electric and Gas
39710-RIELEC-COMM EQUIP SITE SPECIF	GAS	3971012	BATTERY CHARGER	5360-Narragansett Electric and Gas
39710-RIELEC-COMM EQUIP SITE SPECIF	GAS	3971012	CABLE	5360-Narragansett Electric and Gas
39710-RIELEC-COMM EQUIP SITE SPECIF	GAS	3971012	EUA CONVERSION ASSETS	5360-Narragansett Electric and Gas
39710-RIELEC-COMM EQUIP SITE SPECIF	GAS	3971012	TEST RU FOR TEST CONVERSION ONLY	5360-Narragansett Electric and Gas
39710-RIELEC-COMM EQUIP SITE SPECIF	GAS	3971012	BUILDING COMMUN & DATA CABLING PLNT	5360-Narragansett Electric and Gas
39710-RIELEC-COMM EQUIP SITE SPECIF	GAS	3971012	BUILDING SPECIALTY ELEC SYSTEM	5360-Narragansett Electric and Gas
39710-RIELEC-COMM EQUIP SITE SPECIF	GAS	3971012	POLES ALL SIZES INC.GUY,ANCHOR,XARM	5360-Narragansett Electric and Gas
39710-RIELEC-COMM EQUIP SITE SPECIF	GAS	3971012	CONDUIT ALL SIZES INC. RISER & HAND	5360-Narragansett Electric and Gas
39710-RIELEC-COMM EQUIP SITE SPECIF	GAS	3971012	DISCONNECT /CIRCUIT BREAKER SWITCHE	5360-Narragansett Electric and Gas
39710-RIELEC-COMM EQUIP SITE SPECIF	GAS	3971012	CABINET/PANELBOARD W/DEVICES	5360-Narragansett Electric and Gas
39710-RIELEC-COMM EQUIP SITE SPECIF	GAS	3971012	POWER OR RINGING CURRENT SUPPLY DEV	5360-Narragansett Electric and Gas
39710-RIELEC-COMM EQUIP SITE SPECIF	GAS	3971012	REPEATER	5360-Narragansett Electric and Gas
39710-RIELEC-COMM EQUIP SITE SPECIF	GAS	3971012	BATTERY	5360-Narragansett Electric and Gas
39710-RIELEC-COMM EQUIP SITE SPECIF	GAS	3971012	STANDBY GENERATOR INC. TANKS	5360-Narragansett Electric and Gas
39710-RIELEC-COMM EQUIP SITE SPECIF	GAS	3971012	EQUIPMENT HOUSING	5360-Narragansett Electric and Gas
39710-RIELEC-COMM EQUIP SITE SPECIF	GAS	3971012	YARD GRADING OR SURFACING	5360-Narragansett Electric and Gas
39710-RIELEC-COMM EQUIP SITE SPECIF	GAS	3971012	TOWER	5360-Narragansett Electric and Gas
39710-RIELEC-COMM EQUIP SITE SPECIF	GAS	3971012	TELEPHONE ANSWERING DEVICE	5360-Narragansett Electric and Gas
39710-RIELEC-COMM EQUIP SITE SPECIF	GAS	3971012	PBX SYSTEM	5360-Narragansett Electric and Gas
39710-RIELEC-COMM EQUIP SITE SPECIF	GAS	3971012	TRANSMITTER/RECEIVER	5360-Narragansett Electric and Gas
39710-RIELEC-COMM EQUIP SITE SPECIF	GAS	3971012	REMOTE CONTROL UNIT	5360-Narragansett Electric and Gas
39710-RIELEC-COMM EQUIP SITE SPECIF	GAS	3971012	ANTENNA/ANTENNA MAST	5360-Narragansett Electric and Gas

Utility Account Description	Segment	utility_account_id	retire_unit	company
39710-RIELEC-COMM EQUIP SITE SPECIF	GAS	3971012	POWER SUPPLY	5360-Narragansett Electric and Gas
39710-RIELEC-COMM EQUIP SITE SPECIF	GAS	3971012	ENCODER/DECODER	5360-Narragansett Electric and Gas
39710-RIELEC-COMM EQUIP SITE SPECIF	GAS	3971012	RESONANT CAVITY FILTERS/DUPLEXERS	5360-Narragansett Electric and Gas
39710-RIELEC-COMM EQUIP SITE SPECIF	GAS	3971012	MICROWAVE WAVE GUIDE	5360-Narragansett Electric and Gas
39710-RIELEC-COMM EQUIP SITE SPECIF	GAS	3971012	ALARM CONTROL REMOTE RESPONDER	5360-Narragansett Electric and Gas
39710-RIELEC-COMM EQUIP SITE SPECIF	GAS	3971012	MULTIPLEX COMMON & INDIVIDUALEQUIP.	5360-Narragansett Electric and Gas
39710-RIELEC-COMM EQUIP SITE SPECIF	GAS	3971012	POWER SUPPLY LINE TO SITE	5360-Narragansett Electric and Gas
39710-RIELEC-COMM EQUIP SITE SPECIF	GAS	3971012	JACK FIELD	5360-Narragansett Electric and Gas
39710-RIELEC-COMM EQUIP SITE SPECIF	GAS	3971012	DEHYDRATOR	5360-Narragansett Electric and Gas
39710-RIELEC-COMM EQUIP SITE SPECIF	GAS	3971012	MICROWAVE TEST EQUIPMENT	5360-Narragansett Electric and Gas
39710-RIELEC-COMM EQUIP SITE SPECIF	GAS	3971012	FIBER OPTIC CABLE - ALL SIZES	5360-Narragansett Electric and Gas
39710-RIELEC-COMM EQUIP SITE SPECIF	GAS	3971012	FIBER OPTIC TERMINAL EQUIPMENT - AL	5360-Narragansett Electric and Gas
39710-RIELEC-COMM EQUIP SITE SPECIF	GAS	3971012	NETWORK MICROWAVE EQUIPMENT	5360-Narragansett Electric and Gas
39710-RIELEC-COMM EQUIP SITE SPECIF	GAS	3971012	FIXED RADIO EQUIP - BASE UNIT	5360-Narragansett Electric and Gas
39710-RIELEC-COMM EQUIP SITE SPECIF	GAS	3971012	FIXED RADIO EQUIP - COMPUTERS	5360-Narragansett Electric and Gas
39710-RIELEC-COMM EQUIP SITE SPECIF	GAS	3971012	FIXED RADIO EQUIP - CONTROLLERS	5360-Narragansett Electric and Gas
39710-RIELEC-COMM EQUIP SITE SPECIF	GAS	3971012	FIXED RADIO EQUIP - RF LINKS	5360-Narragansett Electric and Gas
39750-RIELEC-COMM EQUIP NETWORK AMO	GAS	3975012	NY Network Equipment (amortized)	5360-Narragansett Electric and Gas
39800-FRTRAN-GENERAL PLANT MISCELLA	GAS	3980002	Non-unitized	5360-Narragansett Electric and Gas
39800-FRTRAN-GENERAL PLANT MISCELLA	GAS	3980002	GENERAL PLANT < $20,000	5360-Narragansett Electric and Gas
39800-RIELEC-GENERAL PLANT MISCELLA	GAS	3980012	EUA CONVERSION ASSETS	5360-Narragansett Electric and Gas
39800-RIELEC-GENERAL PLANT MISCELLA	GAS	3980012	GENERAL PLANT < $20,000	5360-Narragansett Electric and Gas
39800-RIELEC-GENERAL PLANT MISCELLA	GAS	3980012	GENERAL PLANT $20,000 OR >	5360-Narragansett Electric and Gas
39900-RIELEC-OTHER TANG PROP ELEC G	GAS	3990012	EUA CONVERSION ASSETS	5360-Narragansett Electric and Gas
35000-FRTRAN-LAND&LAND RIGHTS FUT		35010502	LAND	5360-Narragansett Electric and Gas
35000-FRTRAN-LAND&LAND RIGHTS FUT	Electric	35010502	LAND RIGHTS & ADDITIONAL COSTS	5360-Narragansett Electric and Gas
35900-FRTRAN-ROADS AND TRAILS FUT	Electric	35910502	LAND	5360-Narragansett Electric and Gas
35900-FRTRAN-ROADS AND TRAILS FUT	Electric	35910502	BRIDGES	5360-Narragansett Electric and Gas
36000-RIELEC-LAND&LANDRIGHTS NE FUT	Electric	36010512	LAND	5360-Narragansett Electric and Gas
36000-RIELEC-LAND&LANDRIGHTS NE FUT	Electric	36010512	LAND RIGHTS & ADDITIONAL COSTS	5360-Narragansett Electric and Gas
12134100-FRTRAN-BUILDG & ADDITS OTH		1213410002	Non-Utility Property - Land	5360-Narragansett Electric and Gas
12135200-RIELEC-STRCT&IMPRVE TRANS		1213520012	Non-Utility Property - Land	5360-Narragansett Electric and Gas
12135300-RIELEC-TRANSM STATION EQU		1213530012	Non-Utility Property - Land	5360-Narragansett Electric and Gas

Division 1-22

Request:

Provide the workpapers that support NWA-2 Gas (2016 Gas Depreciation Study). When possible, provide the work papers and other documents requested electronically in Excel (or in text delimited format if not available in Excel.)

Response:

The Company provided the workpapers that support Schedule NWA-2 Gas as part of its November 27, 2017 initial filing with the Public Utilities Commission in this docket.

Prepared by or under the supervision of: Ned Allis