ROCKLAND ELECTRIC COMPANY
Testimony of
ELECTRIC RATE PANEL

Q. Would the members of the Electric Rate Panel ("Panel") please state their names and business addresses?

A. William Atzl, Cheryl Ruggiero, and Lucy Villeta, 4 Irving Place, New York, New York 10003.

Q. By whom are you employed, in what capacity, and what are your professional backgrounds and qualifications?

A. **(Atzl)**. I will act as chairman of the Panel. We are all employed by Consolidated Edison Company of New York, Inc. ("Con Edison"). I am Director of the Rate Engineering Department. My background is as follows: In 1983, I graduated from the State University of New York at Stony Brook with a Bachelor of Engineering degree in Mechanical Engineering. In 1989, I graduated from Pace University, White Plains, New York with a Master of Business Administration degree in Management Information Systems. I am a Licensed Professional Engineer in the State of New York. My first employment was with Long Island Lighting Company in 1983 where I held the position of Assistant Engineer in the New Business Department. In 1984, I joined Orange and Rockland Utilities, Inc. ("Orange and Rockland") as a Commercial and Industrial Representative in the Commercial Operations Department. At Orange and Rockland, I also held the positions of Commercial and Industrial Engineer, Program Administrator - Demand-Side Management, Manager - Demand-Side Management Operations, Manager - Energy Services and Pricing, and Manager – Regulatory Affairs. In October 1999, I joined Con Edison and held the position of Department Manager – Electric and Gas Rate Design – O&R and Director prior to my present position. I have testified in numerous regulatory proceedings before the New Jersey Board of Public Utilities ("BPU"), Pennsylvania Public Utility Commission ("PAPUC") and New York Public Service Commission ("NYPSC").

(Ruggiero) I am Department Manager of the O&R Rate Design section of the Rate Engineering Department. I received a Bachelor of Science Degree in Electrical Engineering from Polytechnic University in 2000 and a Master of Business Administration Degree in Finance from Baruch College in 2009. In 2000, I began my employment with Con Edison as a Management Intern with rotational assignments in Electric Operations, Engineering Services, and Gas Operations. In July 2001, I accepted a position as an Associate Engineer - A in Distribution Engineering. In November 2005, I accepted a position as a Senior Analyst in Rate Engineering and have held titles of increasing responsibility. I was promoted to my current position in March 2013. I have testified before the NYPSC and I also have submitted testimony before the BPU and PAPUC.

(Villeta) I am Section Manager of the Cost Analysis section of the Rate Engineering Department. I received a Bachelor of Business Administration Degree in Finance with a minor in Management Information Systems from Pace University in September 1989. In October 1989, I began my employment with Con Edison as a Management Intern with rotational assignments in Forecasting and Economic Analysis, Accounting Research and Procedures ("ARP") and Power Generation Services. In June 1990, I accepted my permanent assignment as an Associate Accountant in ARP. In 1995, I was promoted to Budget Analyst in Central Customer Service. In 1998, I was promoted to Senior Analyst in Customer Operations responsible for managing the Call Center and Service Center budget. In 2001, I was promoted to Financial Manager of Staten Island and Electric Services. I have been in my current position since November 2005. I have testified before the BPU in the Rockland Electric Company ("RECO" or "the Company") base rate proceedings in BPU Docket No. ER06060483 and BPU Docket No. ER09080668. I also have testified before the NYPSC and PAPUC.

Q. Are you sponsoring any exhibits?

A. Yes. We are sponsoring Exhibit P-5 and Exhibit P-7.

Q. Please describe the general arrangement of Exhibit P-5.

A. Exhibit P-5 is comprised of ten schedules. The first six schedules relate to the rate design associated with the Company-sponsored Embedded Cost-of-Service ("ECOS") study and the last four schedules relate to the rate design associated with the Staff-endorsed ECOS study.

Q. Please describe the general arrangement of Exhibit P-7.

A. Exhibit P-7 is comprised of two schedules. Schedule 1 is the Company-sponsored ECOS study and Schedule 2 is the Staff-endorsed ECOS study.

Q. What is the scope of your direct testimony in this proceeding?

A. We will present:

(1) The Company's ECOS study (also referred to as the "Company-sponsored ECOS");

(2) A version of the Company's ECOS study developed in compliance with the Stipulation of Settlement approved by the BPU in BPU Docket No. ER09080668 (also referred to as the "Staff-endorsed ECOS");

(3) The Company's proposed revenue allocation and rate design;

(4) The impact of the proposed rate changes on customers' bills; and

(5) The Company's proposed tariff revisions.

Q. Please summarize your testimony related to the ECOS studies.

A. First, the Panel will present the Company's ECOS study for calendar year 2012 which:

- Functionalizes and classifies various electric system costs to their operating functions;
- Allocates these functionalized costs to the customer classes;
- Reflects a total system rate-of-return of 5.78%, a Total Residential rate-of-return of 0.51%, a Total Commercial and Industrial ("C&I") rate-of-return of 15.17%, a Municipal Lighting rate-of-return of 1.28%, a Private Lighting rate-of-return of (8.02%) and a Total Primary rate-of-return of 10.64%; and

- Demonstrates each ECOS study class's revenue surplus or deficiency based on the application of ± 10% tolerance band around the calculated total system rate-of-return.

Second, the Panel will discuss the Company's opposition to the BPU's adoption of the Staff-endorsed ECOS methodology.

COMPANY-SPONSORED ECOS STUDY

Q. Please begin with your presentation of the Company-sponsored ECOS study.

A. The Company-sponsored ECOS study is contained in a document entitled "Rockland Electric Company – Company-sponsored Embedded Cost of Service Study – Year 2012" and identified as Exhibit P-7, Schedule 1.

Q. Was this ECOS study prepared under your direction and supervision?

A. Yes.

Q. What time period does this ECOS study cover?

A. This ECOS study covers RECO's operations for calendar year 2012.

Q. What is the scope of this ECOS Study?

A. This ECOS study is for the electric distribution portion of the Company's operations. The revenues, expenses and rate base associated with Purchased Power and Transmission are not included in the study.

Q. What electric revenues are reflected in this ECOS study?

A. Electric revenues are 2012 book distribution revenues, including Smart Grid Surcharge revenues, by RECO service classifications ("SCs").

Q. What customer classes are analyzed in this ECOS study?

A. A description of the type of customers served under each SC is shown on pages 8 through 10 of the Explanation of Costing Methods and Tabular Results ("explanatory notes") prefaced in Schedule 1. These classes are incorporated in the ECOS study starting in column (7) on each Table on Pages 2-4.

Q. How are the results of this ECOS study expressed?

A. The results of this ECOS study are expressed as Total Company ("total system") and class-by-class rates of return.

Q. What is the total system rate of return shown in this ECOS study?

A. The total system rate of return, shown on Table 1, Page 1, Column (1), Line 16 of this ECOS study, is 5.78%.

Q. What are the class rates of return shown in this ECOS study?

A. The following class rates of return are shown on Table 1, Page 1, and Line 16 of this ECOS study:

- Total Residential – 0.51%;
- Total C&I – 15.17%;
- Municipal Lighting – 1.28%;
- Private Lighting – (8.02%); and
- Total Primary – 10.64%.

Q. Does the Company employ "tolerance bands" around the system rate-of-return in developing class revenue responsibilities?

A. Yes. Class revenue responsibility has been measured with respect to a ±10% tolerance band around the total system rate-of-return. Classes would not be considered "surplus" or "deficient" if the class ECOS rate-of-return falls within this band. Classes that fall outside this range would be either surplus or deficient by the revenue amount, including appropriate income taxes, necessary to bring the realized return to the upper or lower limit of the tolerance band.

Q. Does the ECOS study contain an analysis of customer costs by class of service?

A. Yes. Please refer to Table 6, Page 1, and Line 14 of this ECOS study. The monthly customer costs by class are as follows:

- Total Residential – $23.63;
- Total C&I – $58.80;
- Municipal Lighting – $2,323.62;

- Private Lighting – \$54.90; and
- Total Primary – \$1,109.98.

Q. What do customer costs include?

A. Customer costs include the customer component of transformers, lines, services, meter and meter installations, installations on customers' premises, street lighting, customer accounting, uncollectibles and customer service.

Q. Let us now turn to the methodology used in developing this ECOS study. Please describe the procedures followed in preparation of this study.

A. There are two main steps in the preparation of this ECOS study: (1) functionalization and classification of costs to operating functions, such as distribution, customer accounting and customer service (with further division into sub-functions such as, distribution-overhead transformers, and distribution-services), and (2) allocation of these functionalized costs to customer classes.

Q. Please describe the functionalization and classification step.

A. The functionalization and classification step assigns the broad accounting-based cost categories to the more detailed categories used in this ECOS study. This breakdown is required, for example, to differentiate distribution-demand (*e.g.*, High Tension) related costs from distribution-customer (*e.g.*, Meters & Meter Installations), so that fixed costs can be allocated to the classes correctly. During the process of functionalization, all costs are classified as being demand-related, customer-related or revenue-related. Demand-related costs are fixed costs created by the peak loads placed on the various components of the electric system. Customer-related costs are fixed costs, which are caused by the presence of customers connected to the system.

Q. Please describe the allocation step.

A. The allocation step allocates the functionalized and classified costs to the customer classes based on the appropriate demand, customer or revenue allocation factors, which are shown on Table 7 of this ECOS study.

Q. Does this ECOS study differ from the study RECO filed in BPU Docket No. ER09080668?

A. Yes, this ECOS study introduces a Customer Component Transformer function to be included as part of customer costs. This change recognizes that low-tension distribution plant accounts include both demand and customer components, whereby the number and size of transformers installed directly relate to the presence of customers on the utility's system as well as the expected load carrying capability.

STAFF-ENDORSED EMBEDDED COST-OF-SERVICE STUDY

Q. Please describe the Staff-endorsed ECOS study.

A. In the Stipulation of Settlement (see, Paragraph 6) approved by the BPU in RECO's last electric base rate case, BPU Docket No. ER09080668 ("Stipulation of Settlement"), the Company agreed to prepare and submit with its filing in its next electric base rate case, an ECOS study consistent with Staff's proposed Average and Peak methodology. The Company reserved and retained the right to oppose the methodology or results of Staff's proposed Average and Peak methodology or any rate design based thereon. This Staff-endorsed ECOS study is contained in a document entitled "Rockland Electric Company – Staff-Endorsed Embedded Cost of Service Study – Year 2012" and identified as Exhibit P-7, Schedule 2.

Q. How does this study differ from the Company-sponsored ECOS study?

A. The Staff-endorsed ECOS study differs from the Company-sponsored ECOS study in a number of material respects. The most significant distinction is Staff's advocacy of the Average and Peak methodology for allocating distribution costs.

Q. Please describe the Average and Peak methodology advocated by Staff.

A. The Average and Peak methodology endorsed by Staff uses energy and demand components of the system load factor to incorrectly functionalize and classify distribution costs into energy and demand.

Q. Does the Company agree with the use of the Average and Peak methodology for allocating distribution costs as advocated by Staff?

A. No.

Q. Please explain.

A. While Staff's use of energy is recognized by the National Association of Regulatory Utility Commissioners' ("NARUC") Electric Utility Cost Allocation Manual ("Manual") as an appropriate method of allocating production costs, it should not be used to functionalize and allocate distribution costs. The Manual (Chapter 6, page 89) specifically states, "Because there is no energy component of distribution-related costs, we need consider only the demand and customer components." Nowhere in the Manual does NARUC endorse the Average and Peak method, or any other energy-based method, of allocating distribution costs.

Q. Please continue.

A. The Company-sponsored ECOS study submitted in this proceeding is a distribution-only study as the Company owns no production assets. The Company's ECOS study allocates distribution-demand assets on the basis of non-coincident peaks ("NCPs") (*i.e.*, class peak demands that are non-coincident with the system peak) and individual customer maximum demands ("ICMDs").

Q. Is the use of NCPs and ICMDs appropriate for allocating distribution costs?

A. Yes. The Company's allocation of distribution costs using both NCPs and ICMDs follows the guidelines set forth in the Manual regarding the use of class peaks and individual customer peaks in allocating distribution costs. In the Manual (Chapter 6, pages 96 and 97), NARUC states that:

> Distribution facilities, from a design and operational perspective, are installed primarily to meet localized area loads. Distribution substations are designed to meet the maximum load from the distribution feeders emanating from the substation. Similarly, the distribution engineer designs primary and secondary

> distribution feeders so that sufficient conductor and transformer capacity is available to meet the customer's loads at the primary and secondary distribution service levels. Local area loads are the major factors in sizing distribution equipment. Consequently, customer-class non-coincident demands (NCPs) and individual customer maximum demands are the load characteristics that are normally used to allocate the demand component of distribution facilities.

Q. How else does the Staff-endorsed ECOS materially differ from the Company-sponsored ECOS?

A. Staff's method significantly alters the use of the model's output in calculating customer costs. Specifically, Staff entirely excludes Uncollectibles and Customer Service from customer costs and reassigns these costs to the revenue and energy function, respectively. Staff further excludes Supervision and Miscellaneous Customer Accounts 901 and 905 and reclassifies these costs to the energy function. In contrast, the Company deems these expenses to be entirely customer-related in accordance with industry practice.

Q. Do you have any concluding comments on the use of Staff's proposed ECOS methodology?

A. Yes. As previously explained, use of the Staff-endorsed methodology in this proceeding is inappropriate. The use of the Average and Peak method is reserved for the allocation of production related costs to classes. The use of Average and Peak to assign distribution related costs to the classes is not supported by costing guidelines nor is it traditional utility practice. The Company is presenting a distribution-only study that requires that costs be allocated on a demand basis. This method allows for the proper allocation of costs to the classes based on cost-causation. Allocating distribution costs based on an energy component is fundamentally incorrect and produces results that improperly over-assign cost responsibility to classes with higher energy use.

REVENUE ALLOCATION

Q. What is the basis for the total incremental distribution revenue requirement for the test year, *i.e.*, the 12 months ending March 2014 ("Test Year"), that you utilized in your proposed rate design?

A. The total proposed revenue increase of $19,259,000, excluding sales and use tax ("SUT"), was provided by Company witness Kane. This amount will be applied as an increase to distribution rates.

Q. How was this distribution revenue increase allocated to the Company's various SCs?

A. Test Year distribution revenues, excluding SUT and the Transitional Energy Facility Assessment ("TEFA"), for each SC were realigned to address the deficiency and surplus indications from the Company-sponsored ECOS study. In doing so, the SCs were separated into the following groupings: SC No. 1 Residential Service, SC No. 2 General Service Secondary Non-Demand Billed, SC No. 2 General Service Secondary Demand Billed, SC No. 2 General Service Space Heating, SC No. 2 General Service Primary, SC No. 3 Residential Time-of-Day Heating Service, SC No. 4 Public Street Lighting Service, SC No. 5 Residential Space Heating Service, SC No. 6 Private Overhead Lighting Service - Dusk to Dawn, SC No. 6 Private Overhead Lighting Service – Energy Only, SC No. 7 Large General Time-Of-Day Service – Primary, SC No. 7 High Voltage Distribution and SC No. 7 Space Heating.

Q. Why was the TEFA removed from distribution revenues?

A. In accordance with BPU Docket No. EO11110800, In the Matter of the Phase Out of the Transitional Energy Facility Assessment ("TEFA") Pursuant to N.J.S.A. 48:2-21.34 (5) and N.J.S.A. 54:30A-102, the TEFA rates currently embedded in distribution rates will be entirely phased out effective January 1, 2014. Therefore, since new rates will become effective after this date, the Company has chosen to represent all distribution rates at the January 1, 2014 level (*i.e*., with TEFA removed).

Q. Did you attempt to eliminate fully the deficiencies and surpluses indicated by the Company-sponsored ECOS study?

A. Before making final decisions on the elimination of the deficiencies and surpluses, we considered the overall impacts of the realignment and change to distribution revenue by SC. After the realignment process, we allocated the distribution revenue increase among the SCs in proportion to the relative contribution made by each class to the realigned total Test Year distribution revenues. We then reviewed, by SC, the combined impact of eliminating a deficiency or surplus and the impact of the distribution revenue increase. We found that fully eliminating the deficiencies and surpluses, coupled with the distribution revenue increase, would result in very large revenue impacts for SC No. 1 Residential Service, SC No. 2 General Service Secondary Demand Billed, SC No. 2 General Service Primary, SC No. 3 Residential Time-of-Day Heating Service, SC No. 4 Public Street Lighting Service, SC No. 6 Private Overhead Lighting Service – Dusk to Dawn, and SC No. 6 Private Area Lighting Service – Energy Only as compared with SC No. 2 General Service Non-Demand Billed, SC No. 2 General Service Space Heating, SC No. 5 Residential Space Heating Service, SC No. 7 Large General Time-Of-Day Service – Primary, SC No. 7 Space Heating, and SC No. 7 High Voltage Distribution. Therefore, we made mitigation adjustments, on an overall revenue neutral basis, to limit the class-specific distribution increase percentages to no more than 1.25 times the overall distribution increase percentage, with the exception of SC No. 6 Private Overhead Lighting Service – Dusk to Dawn, as described below. Classes having significant deficiencies, which were mitigated in this manner, are SC No. 1 Residential Service, SC No. 3 Residential Time-of-Day Heating Service, SC No. 4 Public Street Lighting Service, and SC No. 6 Private Overhead Lighting Service - Energy Only.

Q. What other considerations did you address in your approach to eliminate the deficiencies and surpluses indicated by the Company-sponsored ECOS study?

A. As part of the Stipulation of Settlement, RECO further reduced the deficiencies in SC No. 4 Public Street Lighting Service and SC No. 6 Private Overhead Lighting Service - Dusk to Dawn by increasing distribution revenues for these classes by 2.0 times and 2.5 times the overall distribution increase percentage for SC No. 4 Public Street Lighting Service and SC No. 6 Private Overhead Lighting Service - Dusk to Dawn, respectively. As can be seen in the Company-sponsored ECOS study, the SC No. 4 Public Street Lighting Service class has a deficiency that is much less than the deficiency determined in the 2008 Company-sponsored ECOS study. Therefore, we included SC No. 4 with the group of SCs for which we limited the distribution increase percentages to no more than 1.25 times the overall distribution percentage increase. A large deficiency still remains for SC No. 6 Private Overhead Lighting Service – Dusk to Dawn. In order to make further progress in reducing the distribution revenue deficiency associated with SC No. 6 Private Overhead Lighting Service – Dusk to Dawn, we are proposing a mitigation adjustment for this class to limit the class-specific distribution increase percentage to 1.5 times the overall distribution increase percentage. In addition, we implemented mitigation adjustments to limit the distribution revenue changes such that no class received a revenue decrease. SC No. 2 General Service Secondary Demand Billed and Primary were mitigated in this manner. The realignment of revenues, with the mitigation adjustments described above, will move the classes in the direction of more closely matching costs and revenues, while limiting the customer bill impacts associated with the changes.

RATE DESIGN

Q. How is this proposed revenue increase for each class applied in determining the Company’s proposed distribution rates shown in Schedule 1 of Exhibit P-5?

A. In order to compute the proposed distribution rates, billing determinants by rate block must be used. These "by-block" billing determinants are available only for historic periods. Therefore, we restated the Test Year distribution revenue increases by class based on the twelve months ended September 30, 2013, *i.e.*, the historical period for which detailed billing data are available.

Q. How did you compute the distribution revenue increase applicable to the historic period?

A. We computed revenue ratios for each class by dividing the historical period distribution revenues excluding SUT and TEFA for each class by projected Test Year distribution revenues for each class at current rate levels. We then applied these ratios, by class, to the Test Year distribution revenue increases to determine each class's distribution revenue increase for the historic period.

Q. How were the revenue increases applied within each SC?

A. In general, proposed distribution rates within each SC were developed by applying uniform percentage increases, specific to each SC, to all distribution rates, including customer charges. The uniform percentage for each SC was calculated by dividing the historic period distribution revenue increase for the SC by the distribution revenue for the SC produced by all current distribution rates, including customer charges.

Q. Were there any exceptions to this approach?

A. Yes. The Company-sponsored ECOS study results for the SC No. 7 High Voltage Distribution class customer cost indicates a customer cost that is below the current customer charge. Therefore, we set the customer charge equal to the current customer cost indicated in the Company-sponsored ECOS study and then increased this amount by the overall percentage increase for the class. After increasing the customer charge, we determined the net amount remaining of the proposed increase for the class. Based on this net amount of proposed increase, we calculated a uniform percentage increase to apply to the remaining distribution rates for the SC No. 7 High Voltage Distribution class.

Q. Did you propose any changes to the space and water heating discounts in SC No. 1?

A. Yes. Space and water heating rates were set in a manner to reduce the level of discount by 50% from the current discount level for the water heating summer rate, the space heating winter rate and the water heating winter rate. This SC No. 1 change was performed on a revenue-neutral basis prior to applying the class-specific increase. The proposals for the space and water heating discounts are contained in the Company's "Analysis of the Impacts of Increasing the Block Usage Limit and Decreasing Space and Water Heating Discounts In Service Classification No. 1" included in Exhibit P-5, Schedule 5.

Q. Are you proposing any structure changes to SC No. 1?

A. Yes. In the Stipulation of Settlement (see Paragraph 8), the Company agreed "to examine in its next base rate case the appropriateness of the residential first block threshold of 250 kWh." We have performed this evaluation and, as a result, the Company is proposing to increase the residential first block threshold from 250 kWh to 600 kWh.

Q. How did you determine 600 kWh as the first block threshold?

A. We analyzed the average monthly usage of SC No. 1 customers over the prior three years and used this analysis as the basis for choosing the 600 kWh. We found that the minimum average monthly usage is approximately 600 kWh. We consider this amount to be the customer's base usage. We consider usage above this level to represent discretionary usage for which a higher summer rate is appropriate.

Q. How did you revise rates to reflect the new 600 kWh first block threshold?

A. After making the previously described revenue neutral changes to the space and water heating discounts, we applied the distribution revenue increase applicable to SC No. 1 on a uniform percentage basis to the distribution rates, including the customer charge. We then applied the change to the SC No. 1 block limit from 250 kWh to 600 kWh in a revenue neutral manner. The proposals for the block structure changes for SC No. 1 are contained in the Company’s "Analysis of the Impacts of Increasing the Block Usage Limit and Decreasing Space and Water Heating Discounts In Service Classification No. 1" included in Exhibit P-5, Schedule 5.

Q. Why did you revise the block structure after applying the distribution revenue increase?

A. The block rate structure for SC No. 1 is applicable to both distribution charges and, for full service customers, Basic Generation Service Fixed Pricing (“BGS-FP”) charges. The BGS-FP charges are determined as part of the annual statewide auction process and become effective on June 1 of each year. Separate block structures for distribution and BGS rates would be quite confusing for SC No. 1 customers. Therefore, the Company proposes that the proposed SC No. 1 block structure change become effective coincident with the new BGS-FP charges that will become effective June 1, 2015. The Company will include a proposal to change the SC No. 1 block structure in the Rockland Electric Company Specific Addendum it files for the 2015 Statewide BGS Auction.

Q. Are you proposing rate structure changes in any other service classifications?

A. Yes. We are including a proposal to eliminate the declining block rates in SC No. 2. Specifically, we propose, on a revenue neutral basis and prior to applying the distribution revenue increases, to eliminate fully declining block usage rates and, where applicable, demand rate differentials in SC No. 2 General Service Non-Demand Billed and SC No. 2 General Service Primary. In addition, for SC No. 2 General Service Primary, we are proposing to shift 30% of costs from the usage charge to the demand charge. For SC No. 2 General Service Secondary Demand Billed, we propose to eliminate 33% of the current usage rate differentials and eliminate a corresponding portion of demand rate differentials. These proposals are based on the Company’s "Analysis of the Impacts of Eliminating Block Usage Rates in Service Classification No. 2" included in Exhibit P-5, Schedule 6.

Q. Would you please describe Schedules 2 through 4 of Exhibit P-5?

A. Yes. Schedule 2 shows the calculation of the Company's proposed distribution rates, including SUT. Schedule 3 shows the effects that proposed rates will have on bills of SC Nos. 1, 2, 5 and 7 customers at various levels of consumption. Schedule 4 is a summary, by SC, of the Test Year sales, revenues at present and proposed rates, and the increase and percentage increase in revenues that will result from the proposed rate design. The revenues at proposed rates include an estimate of electric supply costs for retail access customers. As shown on Schedule 4, the overall percentage increase on total revenues is 7.6%.

OTHER REVENUE ALLOCATION AND RATE DESIGN SCENARIOS

Q. Did you consider other methods to determine proposed rates in this filing?

A. Yes. As explained above, the Company agreed to provide an ECOS study based on an Average and Peak methodology ("A&P ECOS study"). The 2009 Settlement required that RECO perform a rate design based on an A&P ECOS study, while providing the Company with the flexibility to sponsor any ECOS study and rate design it determines appropriate.

Q. Did you produce a rate design based on an A&P ECOS study? If so, what was the basis for this rate design?

A. Yes. Based on an approach similar to that discussed above, we produced rates and bill impacts for illustrative purposes using the results produced by the Staff-endorsed ECOS study. Briefly, we allocated the incremental distribution revenue requirement by realigning Test Year distribution revenues to reflect the full amount of the deficiency and surplus indications in accordance with the classes' cost responsibilities from the Staff-endorsed ECOS study. Based on the results of this process, we produced comparable schedules to Schedules 1 through 4 of Exhibit P-5 under Schedules 7 through 10 of Exhibit P-5.

Q. Did you implement any mitigation of distribution revenue increases in determining your illustrative rates?

A. No. The 2009 Settlement (p. 5) requires the Company to perform a rate design based on the Staff-endorsed ECOS study that allocates the requested revenue change in accordance with the classes' cost responsibilities. We interpret this requirement to mean that no mitigation should be performed.

Q. Could you please describe the information contained in Schedules 7 through 10 of Exhibit P-5?

A. Yes. Based on the results of the Staff-endorsed ECOS study, Schedule 7 contains illustrative distribution rates. Schedule 8 shows the calculation of the illustrative distribution rates, including SUT. Schedule 9 shows bill impacts using the Staff-endorsed ECOS study for SC Nos. 1, 2, 5 and 7 customers at various levels of consumption. Schedule 10 shows a summary, by SC, of the Test Year sales, revenues at present and proposed rates, and the increase and percentage increase in revenues that will result from the rate design using the results of the Staff-endorsed ECOS study.

Q. Are you recommending that the Board adopt a rate design based on the Staff-endorsed ECOS study?

A. No. As discussed above, the Company does not support the Staff-endorsed ECOS study. Similarly, the Company does not support a rate design based on the Staff-endorsed ECOS study.

STANDBY RATES

Q. Has the Company proposed any changes to its provisions for Standby customers?

A. Yes. The Company is proposing changes to its Standby provisions consistent with those proposed in the on-going Standby Proceeding in BPU Docket No. GO12070600, In the Matter of the Act Concerning the Imposition of Standby Charges Upon Distributed Generation Customers Pursuant to N.J.S.A. 48:2-21 et seq..

Q. Please describe the Company's current standby rate provisions.

A. A standby rate provision is included in SC No. 7 and is applicable to any customer who operates a qualifying facility and requires supplemental, auxiliary or standby service to be supplied by the Company. The Company's standby rate provision recognizes two potential conditions for which standby service could be requested. First, a customer could require standby service for a portion of the customer's self-generation when the generation capacity exceeds the customer's demand for electricity. The standby capacity would be the amount requested by the customer, but not less than said customer's maximum demand as metered by the Company in any previous month. Second, the Company would require a customer to take standby service for all of the customer's generation when the generation capacity is less than the customer's demand. The standby capacity would be the nameplate rating of all the customer's generation facilities interconnected with the Company's system, as determined by the Company.

Q. When would a customer be subject to the standby rate?

A. The Company's standby rate is based on the premise that a customer whose generation operates at less than a 50% availability factor cannot be deemed a reliable source of generation. Therefore, when the availability factor of the customer's generation is less than 50%, that customer would pay the full as used demand charges and be excused from paying the standby charge. When the availability factor of the customer's generation is 50% or greater, the customer would pay the full as used demand charges for its billing demand minus the customer's standby capacity and the customer would pay the standby charge for its standby capacity. When the availability factor of the customer's generation is greater than 90%, the customer would pay the full as used demand charges for its billing demand minus the customer's standby capacity, and the customer would be excused from paying the standby charge.

Q. Please describe the Company's proposed changes to its standby rate provisions.

A. First, the Company has proposed that standby rates would be applicable to not only customers who operate qualifying facilities, but also to customers whose generator meets the definition of distributed generation as defined in N.J.S.A. 48:2-21.37.

The Company also proposes to remove the provision waiving the standby charge for any customer whose generation operates at an availability factor of greater than 90%. Doing so puts the Company in line with the standby provisions of other electric distribution companies in the state. In addition, the Company proposes to remove the provision that the availability factor should be calculated for each billing period of an SC No. 7 customer's bill. If not removed, this provision could lead to situations where a customer could have an availability factor greater than 50% in one period and less than 50% in another period. In the definition of availability factor, the Company proposes to change the denominator from the customer's standby capacity to the nameplate rating of the customer's generation facilities. Under the current definition, a customer with generation capacity exceeding the customer's load could have unreliable generation performance and be deemed to have a high availability factor.

Q. Have you made any other changes to the standby rate provisions?

A. Yes. Currently, SC No. 2 customers who take standby service are required to take service under SC No. 7 because there are no standby rate provisions outside of SC No. 7. Therefore, the Company proposes to add standby rate provisions applicable to demand-billed customers served under SC No. 2, so that SC No. 2 customers will no longer have to take service under SC No. 7 for standby service.

LIGHTING SERVICE CLASSIFICATION CHANGES

Q. What changes are you proposing to the Company's lighting service classifications?

A. The Company provides lighting service under SC Nos. 4 and 6. Under SC No. 4, the Company provides lighting for the public streets of the various municipalities it serves.

Under SC No. 6, the Company provides lighting service beyond the limits of public streets for use of individuals and private or public organizations. Recently, the Company has received inquiries from municipal customers regarding the use of newer technology lighting such as induction and light-emitting diode ("LED") lighting. These types of lighting offer potential energy and maintenance savings as well as being considered "greener" technology than sodium and mercury vapor luminaires. The Company's current tariff does not include these new types of fixtures. Therefore, to meet the requests of customers, we are introducing six new luminaires to our lighting classes: four induction fixtures and two LED fixtures.

Q. Please describe how you arrived at the new luminaire charges.

A. To arrive at the charges for each new luminaire, we have calculated a ratio of the costs of the new fixtures to the costs of the closest existing sodium vapor equivalent and applied this ratio to the proposed per luminaire charge of the closest equivalent fixture. In arriving at this ratio for each proposed luminaire, we have taken into account the longer lives that the induction and LED lights offer over sodium vapor lights.

STORM HARDENING SURCHARGE

Q. Please describe your proposal for a storm hardening surcharge.

A. As outlined in the direct testimony of the Storm Hardening Panel, the Company is proposing various infrastructure improvements in response to the heightened storm activity over the last few years. In order to recover the costs related to these improvements, the Company is proposing a Storm Hardening Surcharge ("SHS"), which will be contained in General Information Section No. 36 of the Company's electric tariff.

Q. Please describe how costs will be recovered through the SHS.

A. The revenue requirement to be recovered through the SHS will be calculated to include a return on investment, a return of investment through depreciation, and the incremental operation and maintenance expenses associated with storm hardening costs. Such investment will include capitalized costs net of deferred taxes related to the improvements. The initial calculation will use the depreciation rates and methodology and the before–tax overall weighted average cost of capital approved by the Board in this proceeding. The SHS will be set based on the Company's projected cost data and resulting revenue requirement and a forecast of the Company's kWh deliveries to customers during a twelve-month period. The SHS will be subject to annual adjustments to reset the SHS to recover the forecasted revenue requirement for the succeeding twelve-month period, plus true-ups for any prior period over- or under-collections, based on the forecasted kWh deliveries for customers during the period in which the revised SHS will be in effect. Each annual filing will also include a recovery of uncollectibles.

Q. How will the Company calculate interest on net over- or under-collections?

A. Interest on net over- or under-collections will be calculated as determined by the Board in its Order dated October 21, 2008 in BPU Docket No. ER08060455. As set forth in that Order, the interest rate shall be the interest rate based on two-year constant maturity Treasuries as published in the Federal Reserve Statistical Release on the first day of each month (or the closest day thereafter on which rates are published), plus 60 basis points, but shall not exceed the Company's overall rate of return. The interest rate will be reset each month. The interest calculation will be based on the net of tax beginning and ending average monthly balance. Simple interest will be calculated each month for any over-recovery or under-recovery and will be deferred for recovery or refund. The simple interest will be recovered or refunded when it is included in the deferred balance at the end of the annual period.

Q. Has the Company calculated an initial surcharge on the proposed tariff leaf?

A. At this time, the Company has not calculated an initial surcharge on its proposed tariff leaf. Therefore, the initial SHS will be set to 0.00 ¢/kWh.

Q. When will the Company calculate a rate for the SHS?

A. The Company will be making a follow-up SHS filing, currently anticipated to be submitted by no later than July 1, 2014. This filing will set forth additional details regarding the costs of the Company's specific storm hardening and resiliency investments and programs, as well as provide for cost recovery through a revised SHS anticipated to become effective on January 1, 2015.

OTHER TARIFF CHANGES

Q. In addition to the rate changes described above, please describe any other changes you are proposing to the Company's electric tariff.

A. We are proposing changes to the following sections of the tariff: (a) the re-inspection fee contained in General Information Section No. 22, "Wiring, Apparatus, and Inspection"; (b) the Company's Smart Grid Surcharge contained in General Information Section No. 36; (c) the establishment in General Information Section No. 38 of a fee for either a customer or Third Party Supplier ("TPS") who requests historic customer usage information greater than twenty-four months old; (d) the Rider "Net Metering and Interconnection for Class I Renewable Energy Systems"; and (e) the Company's Water Heating and Space Heating Special Provisions.

Q. Please describe the Company's re-inspection fee.

A. General Information Section No. 22, Wiring, Apparatus, and Inspection, states that the Company reserves the right to make an inspection of an applicant's premises before connecting any service wires or installing meters. There is no charge for the initial inspection to the applicant; however, if the installation is not in compliance with applicable rules, the Company can charge a fee of $48.63 for any subsequent re-inspections of the installation. The amount of this re-inspection fee was established six years ago.

Q. Please describe your proposed update to the Company's re-inspection fee.

The Company proposes to update the re-inspection fee by applying the applicable man-hour rate to the administrative and field time associated with completing a re-inspection. Specifically, as shown below, the total time required to complete all activities associated with a re-inspection has been multiplied by an average hourly rate of $77.01 for a New Business Services representative.

Activity	Time (min)
Phone call/letter to customer indicating that inspection failed	5
Update work management system	3
Contacts with customer/contractor to arrange re-inspection	3
Visual re-inspection of service installation	5
Travel time	30
Total	46

The labor cost associated with the above-mentioned tasks is $59.42. The mileage component is $8.48 and is based on an average of 15 miles per re-inspection and a rate of 56.5 cents per mile, in accordance with the Internal Revenue Service's 2013 mileage reimbursement rate for the use of personal vehicles. The resulting re-inspection fee is the total of the labor and mileage charge components, or $67.90 per re-inspection. This number was rounded up to a proposed re-inspection fee of $68.00.

Q. Please describe the proposed changes to General Information Section No. 36, Smart Grid Surcharge.

A. Currently, the Company is recovering costs for its Smart Grid Infrastructure Grant ("SGIG") pilot program, implemented pursuant to the Smart Grid Investment Grant Program established by the United States Department of Energy, through the Smart Grid Surcharge ("SGS"). As described in the direct testimony of Company's Smart Grid Panel, in this rate case the Company proposes to roll into base rates all remaining costs associated with the SGIG pilot program. The Company therefore proposes to delete the SGS tariff provision from General Information Section No. 36.

Q. Please describe the new charge applicable to customers and TPS for historical information.

A. The Company's proposal is to initiate a charge of $15.00 to recover the cost of customer or TPS requests for historic customer usage information in excess of twenty-four months old.

Q. Why is such a charge necessary?

A. The Company currently provides customers and/or TPS with twenty-four months of historical customer usage information at no charge. With the TPS supplier market rapidly growing in recent years, the Company anticipates an increase in requests for historical data in excess of twenty-four months. To accommodate the TPS and customer requests without burdening other customers with new costs, the Company will establish a flat charge of $15.00 for each request for customer usage information beyond twenty-four months.

Q. How was the $15.00 charge determined?

A. The $15.00 charge represents the incremental labor costs associated with researching and providing historic usage information beyond the twenty-four months of data that is not readily available in the customer billing system. It takes approximately 23 minutes to retrieve, review, consolidate, and mail the requested usage. The labor cost associated with the above-mentioned tasks is $36.84 per hour for a First Class Customer Service Representative. Multiplying this cost times the approximate time to complete the above-mentioned tasks is results in a charge of $14.12. Adding this amount to estimated costs for materials and postage of $0.88 results in a charge of $15.00.

Q. Have you made any changes with regard to the riders in the RECO electric tariff?

A. Yes. The Net Metering rider was modified to conform to the most current version of N.J.A.C. 14:8-4.

Q. What changes are you proposing to make to the Company's Water Heating and Space Heating Special Provisions?

A. The Water Heating Special Provision is currently contained in SC No. 1 and Space Heating Special Provisions are currently contained in SC Nos. 1, 2, and 7. Language has been added to these SCs to state that the Water Heating and Space Heating Special Provisions will be closed to new customers effective January 1, 2014.

Q. Have you provided tariff leaves setting forth all of the changes you have made?

A. Yes, Exhibit B to the Petition shows all tariff language changes in redline/strikeout format. Exhibit C to the Petition contains two schedules showing side-by-side comparisons of present and proposed distribution rates included in the service classifications and construction charges included in General Information Section No. 17. Present rates are the rates that will become effective January 1, 2014 after the complete phase out of TEFA .

Q. Does this conclude your direct testimony?

A. Yes, it does.

ROCKLAND ELECTRIC COMPANY
DIRECT TESTIMONY OF
JAMES L. BURKE

NJBPU CASE No. ____________

Q. Please state your name and business addresses.

A. James L. Burke, 500 Route 208, Monroe, New York 10950.

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

A. I am employed by Orange and Rockland Utilities, Inc. ("Orange and Rockland" or "O&R"), the parent company of Rockland Electric Company ("RECO" or the "Company"), where I hold the position of Director – Customer Meter Operations for O&R, RECO and Pike County Light & Power Company. In that capacity, I am responsible for electric Meter Testing, Meter Shop, Meter Engineering, Meter Translation, Revenue Protection and Customer Field Services which includes meter reading, field collections and field investigations. I have been in this position since July 2001.

Q. Please briefly outline your educational and business experience.

A. I received a BS in Business Management in 1994 from the State University of New York, Old Westbury and an MS in Energy Management from the New York Institute of Technology in 1997. I started my career at the Consolidated Edison Company of New York, Inc. in 1974 as a General Utility Worker and held various union positions. In 1986, I was promoted to District Manager – Manhattan Energy Services. In 1992, I was promoted to Manager of Sales and Marketing and held that position until joining Orange and Rockland in 2001.

Q. Have you previously submitted testimony before the New Jersey Board of Public Utilities ("Board")?

A. No. However, I have provided rate case testimony in New York to the New York Public Service Commission ("NYPSC").

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to address the Company's proposal to install Advanced Metering Infrastructure ("AMI") throughout the Bergen County section of RECO's service territory.

Q. Please describe RECO's AMI proposal.

A. Commencing in 2015, RECO proposes to install, over a five-year period, an AMI system in the Bergen County section of RECO's service territory.

Q. What is the basis for RECO's AMI proposal?

A. To meet the growing needs of our customers, the Company's AMI proposal addresses, and provides benefits, in two key areas. First, implementation of AMI will significantly improve the Company's operating efficiencies in the area of outage management by deploying technologies that enhance outage detection. This will allow for faster response and quicker service restoration. Additionally, from an outage restoration operations perspective, AMI will allow for the identification of nested outages. An example would be in areas where restoration was completed on the main lines of a circuit, but pockets of customers off distribution spurs are still without power. Further, AMI will identify customers already restored and will eliminate unnecessary field visits to these customers. Second, the implementation of AMI will reduce costs for meter reading, as well as the costs associated with the back-office operations required to handle customer billing inquiries.

Q. Has the use of AMI and Advanced Metering technology expanded?

A. Yes, as discussed in the recent report from the Federal Energy Regulatory Commission ("FERC") on the "Assessment of Demand Response and Advanced Metering," issued in October 2013 ("Advanced Metering Report"), there has been a significant growth of AMI in the United States.

The last FERC survey of advanced metering conducted in 2012 and reported in the 2012 Demand Response and Advanced Metering Report, indicated a penetration rate of 22.9 percent. Other sources report similar numbers. Data collected by the Institute for Electric Efficiency ("IEE") in May 2012 indicates that advanced meters represent approximately 23.5 percent of the 166.5 million meters installed. More recently, IEE, which has changed its name to Innovation Electricity Efficiency, released an August 2013 report indicating that as of July 2013 almost 46 million advanced meters have been installed in the United States. IEE's recent data implies an advanced meter penetration rate of approximately 30 percent.

Q. Has there been government support to increase advanced metering deployment?

A. Yes, there has been an increase in support for the deployment of advanced meters at the Federal level. The American Recovery and Reinvestment Act of 2009 ("Recovery Act") appropriated $4.5 billion to the United States Department of Energy ("DOE") for grid modernization programs. Of that amount, $3.4 billion was devoted to the Smart Grid Investment Grant ("SGIG") program, a public-private partnership initiative for leveraging investments in grid modernization. As of June 30, 2013, approximately 12.8 million advanced meters were installed and operational as a result of the SGIG program. Ultimately, 15.5 million advanced meters are expected to be installed and operational pursuant to the SGIG program. All SGIG projects are expected to reach completion between 2013 and 2014.

Q. Was there any other data cited in the FERC's Advanced Metering Report to support the Company's AMI proposal?

A. Yes, the report noted that with recent storm activity and extreme weather events, AMI has facilitated efficient restoration of electric service following outages caused by storm damage. Electric system outages can be the result of small, medium, and very large scale events spanning several states that often impact other infrastructure systems (*e.g.*, communication, financial, and health care). Additionally, as indicated in the report, many state regulators and utilities continue to review system hardening and resiliency measures designed to combat and mitigate future storm damage and outages. The application of new information and communication technologies, including advanced meters, are now a featured component of storm response discussions. Also, some of the information provided in the FERC's Advanced Metering Report indicated how advanced meters integrated with other technologies have helped maintain reliable electric service and enabled faster service restorations during recent weather events. Interval usage data from advanced meters in conjunction with other enabling technologies can expand opportunities for demand response and energy efficiency programs.

Q. What AMI technology is the Company proposing to deploy in Bergen County?

A. The Company plans to install an AMI system by Sensus called Flexnet. The Sensus technology uses a two-way point-to-point radio frequency communication technology protocol which will enable meters to converse directly with tower base radio systems. Meters will be able to send data directly to and from the Company's wide-area network into the Flexnet head-end system which communicates with Company systems such as the Company's Outage Management System and the Customer Information Management System.

Q. Why did the Company choose this particular system?

A. Since 2006, the Company has been assessing various AMI technologies. The considerations assessed by the Company included meter locations, meter density, topography, coverage, reliability, scalability, throughput, functionality and costs versus benefits derived. The Company concluded that Sensus was best suited to meet the Company's requirements.

Q. Did the Company retain an independent consultant as part of these assessments of AMI technologies?

A. Yes, in addition to conducting its own internal assessment, the Company retained the services of Accenture in 2013 to conduct an independent assessment. Accenture determined that the Sensus system was best suited for the Company's service territory and at the lowest cost for deployment.

Q. Please set forth the minimal functionality that should be provided by an AMI system.

A. To date, the Company is unaware of any minimum functionality requirements for AMI systems being installed within the State of New Jersey. However, in New York, as part of Case 09-M-0074, in the "Matter of Advanced Metering Infrastructure," the NYPSC issued an order on February 13, 2009 [http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={16310751-0A41-401D-BFE5-7E95F5B3869D}] describing minimal functionality that it would require by an AMI system as follows:

(a) AMI systems must be compliant with all applicable American National Standards Institute standards, Commission regulations and Federal standards, such as those set forth in the Federal Communication Commission's regulations.

(b) AMI systems must provide net metering.

(c) AMI systems must provide for a visual read of consumption either at the meter or via an auxiliary device. The utility is responsible for providing customers with an auxiliary device if it is the only means to provide a visual read of consumption data.

(d) AMI systems must be able to provide time-stamped interval data with a minimum interval of no more than one hour.

(e) AMI meters must have sufficient on-board meter memory capability so that meter data is not lost in the event of an AMI system failure and that the previous and current billing period of billing data is stored on the meter.

(f) AMI systems must have the ability to provide customers direct, real-time access to electric meter data.

(g) AMI systems must have the ability to remotely read meters on-demand.

(h) At the point where the customer or the customer's agent interfaces with the AMI system, the data exchange must be in an open, standard, non-proprietary format.

(i) AMI systems must have two-way communications capability, including the ability to reprogram the meter and add functionality remotely, without interfering with the operation of the meter.

(j) AMI systems must have the ability to send signals to customer equipment to trigger demand response functions and connect with a home area network to provide direct or customer-activated load control.

(k) AMI systems must have the ability to identify, locate, and determine the extent of an outage, and have the ability to confirm that an individual customer has been restored.

(l) AMI systems must have the following security capabilities:

(i) Identification - uniquely identify all authorized users of the system to support individual accountability;

(ii) Authentication – authenticate all users prior to initially allowing access;

(iii) Access Control - assign and enforce levels of privilege to users for restricting the use of resources, and deny access to users unless they are properly identified and authenticated;

(iv) Integrity – prevent unauthorized modification of data, and provide detection and notification of unauthorized actions;

(v) Confidentiality - secure data stored, processed and transmitted by the system from unauthorized entities;

(vi) Non-repudiation - provide proof of transmission or reception of a communication between entities;

(vii) Availability - information stored, processed and transmitted by the system must be available and accessible when required;

(viii) Audit - provide an audit log for investigating any security-related event; and

(ix) Security Administration – provide tools for managing all of the above tasks by a designated security administrator.

Q. Does the Sensus System meet these requirements?

A. Yes, it does.

Q. Did the Company conduct a market assessment when it reviewed the Sensus proposal?

A. Yes. Sensus is the second leading provider of AMI deployments in the North American market. According to the 2013 Scott Report from Pike Research, they have 20% of the entire market share with over 12.5 metering end-points deployed since 2007. They have also recently won a contract to install an additional 16 million meter end-points in Great Britain.

Q. What is the cost of RECO's implementing the Sensus AMI system?

A. As set forth in Exhibit ___ (JLB-1), the Company estimates that its installation of the Sensus AMI system will cost approximately $16.9 million.

Q. Do you believe that the actual cost may be less than this estimate?

A. Potentially yes. There are a number of areas where the actual cost may be less than estimated. First, the Sensus Flexnet software and communication equipment costs may come in for less once a formal Request for Proposal is generated. Second, the meter costs could be lower when the Company competitively bids the meter purchases to various meter manufacturers who have Sensus technology as part of their standard metering offerings. Third, the tower leasing agreements and communication costs could be lower than projected. Any reductions in the installation costs would be provided to the Board in future updates.

Q. Is there any way the Board could assist in reducing the overall cost of the project?

A. Yes, the Board requires RECO to perform a retirement test on all meters that RECO discards in accordance with N.J.A.C. 14:3-4.7. Based on a review of the current meter assets deployed in Bergen County, approximately 25,000 of the current 58,150 meters would be discarded due to their age. If the Board would grant a waiver of the retirement test for these meters as part of this project, the Company could reduce the project costs by approximately $652,000. The other approximately 33,150 meters would be re-tested and re-used to reduce future capital meter purchases and installations in other areas within the RECO and O&R service territories.

Q. Have you quantified the benefits of RECO's implementing the Sensus AMI system?

A. As set forth in Exhibit ___ (JLB-1), the Company estimates that its installation of the Sensus AMI system will provide benefits totaling approximately $39.8 million over the projected 20 year life of the project with a net benefit of $33.4 million after accounting for recurring operation and maintenance costs of $6.4 million.

Q. Please describe these benefits.

A. First, are the storm restoration/electric operations benefits noted above. In addition to the avoided costs shown in Exhibit __ (JLB-1), these benefits include the impact of reduced outage restoration times for our customers. Second, are avoided capital expenditures that result from the AMI deployment related to meter purchases and installation costs, replacement of meter reading vehicles, replacement of the meter reading system and meters that would need to be replaced for Rate Engineering load study purposes. Third, are operational savings directly related to providing efficient meter reading services and other customer field activity services to our customers such as connects and disconnects. Finally, are operational savings that will reduce costs for other departments such as Call Center costs due to customer inquiries and rebilling required due to estimated meter readings and earlier detection of metering issues.

Q. What are the other benefits that may be obtained from an AMI system?

A. An AMI system may be enhanced to provide other non-quantifiable benefits. An AMI system is both an enabling and transformative technology in the way it will allow utilities to operate going forward. Many of the partially funded DOE AMI projects and other regulatory approved projects across the United States are just beginning to realize and quantify other benefits derived from deploying AMI systems. For example, the ability to remotely upgrade metering firmware greatly reduces the metering costs to change or institute new rates designs. AMI systems also afford utilities with the ability to collect more data, more frequently from the meters (*e.g.*, Kvar readings, voltages). In the area of Energy Efficiency and Demand Response, the AMI communication network with Zigbee enables beyond the meter capabilities to utilities. Customers can start receiving signals such as critical peak, or voluntary load reductions on in-home displays or even to mobile devices thus allowing for better demand response programs. When customers are more aware of their usage either via their in-home displays or via the web, they often adjust their behavior and overall energy usage is reduced. The AMI communication network can also be leveraged to control load on premises if the utility is having some distribution network issues. A mature Demand Response ("DR") program can be developed considering distributed generation solutions, renewables like solar on premise, load reduction by calling a DR event, and curtailing load by controlling such devices as thermostats and pool pumps. The work and equipment necessary to obtain such benefits and their associated costs would be determined after implementing the AMI system. They are not part of this proposal. Societal benefits also would be achieved by reducing environmental concerns through improved air quality from avoided generation and vehicle emissions. Lastly, improved outage management obtained through an AMI deployment would reduce the financial impacts incurred by both commercial and residential customers during an outage.

Q. How does the Company propose to recover the cost of this AMI deployment?

A. As discussed in the direct testimony of the System Enhancement Panel, the Company proposes to recover this cost through the Company's proposed storm hardening surcharge.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT __ (JLB-1)

AMI Financials – Project Cost & Benefits

RECO Bergen County- 58,148 Meter Deployment	
AMI Capital Project	**Project Total w/ OH & Cont**
Electric Meters	$7,983,454
O&R Labor	$3,595,698
System Integration & NJ Retirement Test	$2,397,830
Software, Equipment & Vendor Services	$2,424,265
Materials & Supplies	$498,672
TOTAL	**$16,899,920**
Corporate Expense	**20 YR Estimate**
Reoccurring O&M	$6,344,031
Summary of AMI Benefits	**20 YR Estimate**
Electric Operations	$6,970,541
Avoided Capital	$7,573,217
Customer Meter Operations	$22,647,849
Customer Accounting & Assistance	$463,379
Corporate	$2,106,110

ROCKLAND ELECTRIC COMPANY
DIRECT TESTIMONY OF
SMART GRID PANEL

Q. Would the members of the Smart Grid Panel ("Panel") please state your names and business addresses.

A. (Scirbona) Charlie Scirbona and my address is 390 West Route 59, Spring Valley, New York 10977.

(Frosco) Jacqueline Frosco and my address is 390 West Route 59, Spring Valley, New York 10977.

(Coffey) John Coffey and my address is 390 West Route 59, Spring Valley, New York 10977.

(Durling) Michael Durling and my address is One Blue Hill Plaza, Pearl River, New York 10965.

Q. By whom are you employed, in what capacity, and what are your backgrounds and qualifications.

A. (Scirbona) I am employed by Orange and Rockland Utilities, Inc. ("Orange and Rockland"), the parent company of Rockland Electric Company ("RECO" or the "Company"), as a Department Manager. I have an AAS Degree in Electrical Technology from Westchester Community College and 40 years of increasing responsibilities in utility operations and engineering. Prior to coming to Orange and Rockland, I spent 14 years at New York State Electric & Gas Corporation where I was responsible for designing electric transmission and distribution systems. I later advanced to a position where I concurrently supervised a local engineering department, local meter test shop and the local transportation operations. I came to Orange and Rockland as a Line Supervisor, advancing to Area Line Supervisor, Superintendent of Overhead Line, Superintendent of Substation and Relay Operations, Superintendent of EHV Transmission Operations, Manager of Distribution Engineering and Department Manager of Smart Grid Engineering. Additionally, for three years I concurrently managed Con Edison's Non-Network section, Unit substation section along with Orange and Rockland's Distribution Standards section. I have co-authored the following IEEE papers and authored the following published article:

[1] "Generic Reconfiguration for Restoration," D. Kleppinger, R. Broadwater, C. Scirbona, Electric Power Systems Research Journal, Volume 80, Issue 3, March 2010, Pages 287-295.

[2] "Storm Modeling for Prediction of Power Distribution System Outages," Dan Zhu, Danling Cheng, Robert Broadwater, Charlie Scirbona, Electric Power Systems Research, Vol 77, pp 973-979, 2007.

[3.] "Virtual SCADA Tracks the System," C. Scirbona, Transmission and Distribution World, January 2009.

(Frosco) I am employed by Orange and Rockland, as a Project Manager – Project Management Department. I received a Bachelor of Science Degree from Dominican College, a Master's Degree in Construction Management and a Professional Certificate in Project Management from Polytechnic Institute of New York University in 2013. I have worked at Orange and Rockland for over 25 years. I have held various positions with increasing levels of responsibility including Account Coordinator, Customer Project Manager, Manager and Project Manager. A majority of my career has been in the Operations area in the New Business Department. In the position of Manager, New Business, I was responsible for residential and commercial projects in three states - New York, Pennsylvania, and New Jersey. I directed five-levels of management, whose responsibilities included analyzing field conditions, assisting Operating Departments with planning and scheduling of distribution installations for gas and electricity. In my current position as Project Manager in Orange and Rockland's Project Management Department, I am responsible for the management of capital projects in excess of five million dollars. I perform project management functions associated with major construction projects, primarily for the electric and gas system infrastructure. This includes planning, organizing and directing all aspects of the project to assure completion on schedule and within budget and in accordance with all applicable specifications, drawings, safety, environmental and quality requirements. I provide oversight and leadership for implementation of the project and provide monthly project progress and financial reports to the appropriate Company personnel.

(Coffey) I am employed by Orange and Rockland, as Chief Engineer. I received a Bachelor of Science in Electrical Engineering from Manhattan College in 1988. I am a licensed New York State Professional Engineer. I have over 25 years of electrical engineering experience and have worked for Orange and Rockland for 24 years. I have served as the Orange and Rockland Chief Transmission and Substation Engineer since 2010. This position oversees the planning, engineering and design of capital improvement budget for projects in the Orange and Rockland transmission system. I worked for one year at Burns and Roe Co. in Oradell, New Jersey as an Electrical Engineer prior to my arrival at Orange and Rockland in 1989.

(Durling) I am employed by Orange and Rockland, as Systems Manager – Information Resources. I have over 32 years of experience within the IR – Telecommunications industry, including 25 years at Orange and Rockland. At Orange and Rockland, I have been serving as Systems Manager, Information Technology Planning Department for the past 14 years. This position oversees both the planning and operations of Orange and Rockland's Telecommunications Infrastructure. Previous to this, I held positions at O&R as a Sr. Systems Specialist and Systems Operations Supervisor. I attended Keene State College where I earned credits for a bachelor's degree in the Computer Science field, prior to graduating from Control Data Institute, New York, NY in 1981. Prior to my employment at Orange and Rockland, I was employed at IBM as a Technical Specialist for five years and INNTECH Management, where I served as Service Manager for two years.

Q. Have any members of the Panel previously testified before the Board of Public Utilities?

A. No.

Q. Please briefly explain the purpose of the Panel's testimony in this proceeding.

A. The Panel will discuss RECO's implementation of its Smart Grid Infrastructure Grant ("SGIG") pilot program as approved by the Board in its Order Adopting Stipulation dated April 5, 2010 in Docket No. ER09060459 ("Smart Grid Order"), as well as the benefits that the SGIG pilot program will provide to RECO's customers.

Q. Please describe the objective of RECO's SGIG pilot program.

A. The objective of the SGIG pilot program was to integrate state-of-the-art equipment and technology with advances in computer analysis, communications, monitoring, and control to significantly enhance system reliability, efficiency, and quality of service. This pilot program installed "off the shelf infrastructure and equipment" which when combined with commercially available electronic products and software provides unprecedented information availability for equipment monitoring, engineering analysis and system operation. Additionally, newly developed real time control systems based on a proof of concept model centric approach to system control are being implemented to gain experience with and to optimize this concept.

Q. Please describe the work performed by RECO to implement the SGIG pilot program.

A. RECO performed the following work to implement the SGIG pilot program:

- Constructed a high speed cyber-secure, diverse, backbone communication system to provide adequate and reliable data communications.

- Upgraded the South Mahwah and Darlington substations to enable substation automation, added state of the art equipment for condition monitoring, provided enhanced operational data collection and installed high speed data communications.

- At the Company's Darlington and South Mahwah Substations, upgraded the distribution circuitry and modified the topology to enable enhanced automation thereby allowing for establishing a system of five energy efficient, reliable, self-healing circuits. The Company installed switched shunt capacitor banks to improve efficiency, line reclosers to improve reliability, and Supervisory Control and Data Acquisition ("SCADA") operable switches to enable self-healing. In addition, the Company installed three phase sensors to provide information to electronic power quality nodes for enhanced monitoring of the electrical condition of the distribution system. All of the above mentioned equipment was equipped with two way communications.

Q. Please describe the communications component of the SGIG pilot program.

A. The Company performed the following work to provide the secure, reliable and diverse communications required by the SGIG pilot program.

- The Company established a core fiber infrastructure for data backhaul from two major Company communications hub sites located at the South Mahwah and Darlington substations. This will allow data to be brought back from the RECO service territory to Orange and Rockland's primary energy control center ("ECC") in Spring Valley, New York and to Orange and Rockland's alternate ECC in Blooming Grove, New York. This high capacity fiber loop network was constructed with diverse paths and redundant components, thereby reducing exposure to a single point of failure. As such, it provides alternate pathways in the event of a fiber cable break in any part of the fiber loop network, and redundant electronic equipment protects against loss of communications from electronic equipment failure. The Company also employed this routing and equipment redundancy scheme internal to each hub site, in order to provide a high level of system availability and reliability.
- The Company installed Dense Wavelength Division Multiplexing ("DWDM") technology to provide high-capacity connectivity among all hub and ECC sites. This

arrangement provides ample data capacity for the Company's present and foreseeable future backhaul requirements.

- The Company established communication with its intelligent field devices external to the substations over licensed radio frequency spectrum in the 220MHz band. This was determined to be a reliable radio solution by radio frequency ("RF") propagation studies which were conducted throughout the RECO service territory. The RF study demonstrated good signal strength was achievable, but that the signal strength in the southernmost area of the RECO service territory was weak and unreliable. This unreliability necessitated the addition of another master radio site in order to provide reliable communications to all smart field devices. Based on the RF study, the Company purchased spectrum licenses after field test verification of the study results.
- RECO owns and operates a radio communications site in Mahwah, New Jersey that is used for voice communications between vehicles and the Company's ECC, as well as providing communications paths for corporate data systems. The Company used this site to establish communication with the majority of the field devices, installed pursuant to the SGIG pilot program, in the RECO service territory. Studies were conducted to determine the optimal location for the additional master radio site. After extensive evaluation, RECO determined that establishing the second radio site on existing RECO property in Wyckoff, New Jersey would best accommodate the Company's communication needs. The radio equipment and antenna have been installed at this location and the site is currently scheduled to be on the air by year end 2013.

- The Company maintained cyber security compliance throughout the network design by installing firewalls necessary for meeting newly established corporate standards. The Company also addressed the physical security of the critical components by installing dedicated cabinets with secured locks for use by only authorized personnel. This equipment is segregated from other Company-based communication assets.

Q. Is there adequate space to house this additional equipment at the Company's facilities?

A. There is adequate space available for the addition of secure electronic cabinets within existing structures at all locations, except at the Darlington Substation which required the addition of a new communications shelter to house the required fiber optic equipment. The Company placed a pre-cast building on site after receiving the required approvals from the Town of Ramsey. RECO established redundant and diverse fiber links between this pre-cast building, the control house, South Mahwah substation and the Company's ECCs.

Q. Please describe the details of the South Mahwah Substation Upgrade portion of the SGIG pilot program.

A. The South Mahwah Substation is a 345kV to 138kV to 69kV substation that is located at the interconnection of the NYISO and PJM Regional Transmission Organizations. This station is also a source for local 13.2kV distribution circuitry. Due to the importance of this substation to the Company's electric distribution system, introducing smart grid technology at South Mahwah positions this substation and the Company for the move to faster, more secure real time data driven analysis, decision making and intelligent automated control. These advancements will have a positive effect on both the efficiency and reliability of the Company's distribution system.

As part of the SGIG pilot program, the Company increased the existing 35MVA 13.2kV substation transformer bank at the South Mahwah Substation to a 50MVA bank, and added a second 50MVA bank, and a 138kV underground transmission connection to the 138kV bus within the Substation. These improvements will provide the capacity and redundancy necessary to enable the Company's Smart Grid design methodology and improve reliability. Reliability was enhanced further through the addition of a Smart Automatic transfer scheme that transfers load to the adjacent transformer bank at the South Mahwah Substation upon loss of a bank or bus. The infrastructure benefits are immediate in that capacity at the Substation has been significantly improved and circuit count has increased four to ten. The redundant banks and main buses provide backup capability not previously available.

The transformers are equipped with condition monitoring equipment to permit real time monitoring of critical condition indicators such as transformer winding hot spots, oil temperatures, tap position, and load tap changer ("LTC") motor current. This advanced monitoring of equipment in real time allows for dynamic ratings to be achieved through the analysis of real time operating temperatures. Real time ratings allow for true operation of the equipment ratings per the ambient temperature versus the restriction of only operating by static summer/ winter ratings.

In addition to the substation transformer replacement and new transformer bank addition, the Company implemented several other infrastructure upgrades to accommodate the conversion of South Mahwah to a Smart Grid enabled substation. This includes the installation of state of the art distribution switchgear and ten underground distribution circuit exits. The new switchgear provides new circuit positions to allow for load relief and new circuit breakers for the existing circuits. The switchgear was equipped with smart micro-processor based protective relaying for the substation transformer banks and the distribution circuits. The relays are time synchronized via a Global Positioning System ("GPS") clock, which provides for better diagnostics and more accurate analysis of events and disturbances.

In addition, the Company introduced a time synchronized relay-based breaker monitoring system to identify breaker timing issues and wear. This real time intelligent diagnostic equipment better identifies incipient faults in the units, thereby protecting equipment from failure and enabling replacement of time-based maintenance schedules with condition-based maintenance schedules. All of this should lead to reduced maintenance costs.

The Company also introduced a Substation Enterprise Server which allows secure remote access to the Intelligent Electronic Devices ("IEDs") within the substation. Access to this data allows the Company to perform post-event analysis of incidents prior to dispatching crews to the substation. The Enterprise Server is designed as a North American Reliability Council ("NERC") / Critical Infrastructure Protection ("CIP") compliant solution for advanced user authentication and data encryption. The system automatically creates and manages remote connections, tracks all user activity, proactively prevents unauthorized connection attempts to restricted devices, and provides a centralized collection point for IEDs such as relays and meters. The Enterprise Server also logs critical power system data that feeds into the SCADA system and the distribution analysis and control systems. Additionally, the information will assist in system planning and restoration needs.

Implementing the SGIG pilot program at the South Mahwah Substation required the Company to establish advanced communications abilities through use of fiber-optic connections to increase bandwidth, improve polling speed and transfer information from the existing Remote Terminal Unit ("RTU") to the ECC. The increased bandwidth of the fiber optic communications allows the Company to retrieve more information remotely for analysis. In addition, these dedicated fiber optic lines improve communication reliability, performance, and enhance cyber security.

Q. Please describe the details of the Darlington Substation Upgrade portion of the SGIG pilot program.

A. When the Company constructed the Darlington Substation in 2004, it equipped the Substation with many state of the art IEDs. As part of the SGIG pilot program, the Company implemented the additional modifications, described below, at the Darlington Substation.

- Installed a fiber-optic connection to the Substation thereby increasing and improving the polling speed and transfer of information from the existing RTU to the ECC.
- Installed a new data connection to the Substation via fiber-optic communications for connection to the Company's Enterprise Server. As noted above in the discussion of the South Mahwah Substation upgrade, the Enterprise Server connection allows secure remote access to the devices in the Substation for transfer of data and fault files, thereby allowing for engineering planning analysis and post-event analysis of incidents prior to dispatching crews to the Substation. The Enterprise Server is designed as a NERC/CIP compliant solution for advanced user authentication and data encryption.
- Installed a new Substation Server in order to provide advanced substation functionality, including:
  - Centralized collection point for IEDs such as relays and meters;
  - Data log critical power system quantities used for SCADA, real time control, planning and restoration needs;
  - Automatic fault retrieval and file transfer to the ECC; and
  - Authenticated secure device access.
- Time Synchronization of all protection relays to allow for the time stamping coordination of data from the individual devices within the Substation allowing for more accurate analysis of events and disturbances.
- Upgrade to a Smart Annunciator for increased alarm capability and better decision making by the ECC System Operators. Identifying the actual alarm, instead of

an alarm category, as is currently provided, will facilitate improved system decisions and resource deployment by RECO.

- Connect Transformer and Breaker Diagnostic equipment to the Substation Server for remote interrogation and routine exception reporting in order to increase and improve the reliability of the major components in the Substation. This will help identify incipient faults in the units, better protect equipment from failure, and reduce adverse impacts to customers from service interruptions. Benefits also include the advanced monitoring of equipment in real time which allows for dynamic ratings achieved through the analysis of real time operating temperatures. The intent is for the time-based maintenance schedule currently in place to be modified with a condition-based maintenance schedule.

Q. Please describe the Distribution Circuitry upgrades that the Company implemented as part of the SGIG pilot program.

A. The Company modified the circuitry of the Darlington Substation as follows in order to create a system of the five smart grid circuits:

- Upgraded approximately 990 feet of single phase overhead distribution to three phase and extended the three phase 180 feet to create an overhead mainline circuit tie; and
- To provide load relief to the existing circuitry, re-conductored 1,170 feet of single phase to three phase main line circuitry thereby allowing the system to be reconfigured to create tie between two of the Darlington circuits.

Q. Please describe the other work performed on the South Mahwah circuitry as part of the SGIG pilot program.

A. The Company installed a total of 3,185 feet of three phase double circuit overhead mainline conductor to create the necessary circuit paths for additional circuits originating from the South Mahwah Substation. The upgrade to the South Mahwah Substation included additional 13.2kV breaker positions that allowed two new distribution circuits to be installed which were used to relieve the load on existing circuitry.

One of the South Mahwah 13.2kV circuits serves heavy commercial load on Route 17 and the residential and light commercial load in the Stag Hill Road area. This circuit exceeded its Relief Rating and was quickly approaching its Emergency Rating. The existing ability to transfer load to adjacent circuitry was limited, so reducing the load by transfer to a more lightly loaded circuit was not possible. In order to relieve the loading on this circuit and provide additional distribution circuitry with available capacity to operate within acceptable limits and as part of a smart grid auto-loop design, the Company needed to install two new circuits out of the South Mahwah Substation. These new circuits exit north out of the South Mahwah Substation as underground construction and rise to overhead construction on Airmont Road. Approximately 1,330 feet of electric distribution facilities on Airmont Road, between Island Road and Franklin Turnpike, was rebuilt for a double circuit pole line to accommodate the two new circuits. To accomplish the required distribution circuit reconfigurations, it was necessary to tie the new circuits into the existing circuitry by constructing 1,855 feet of double circuit main line distribution circuitry along Route 17.

Q. Please describe the Company's installation of the Distribution Automation and Smart Grid equipment on the system of five smart grid circuits as part of the SGIG pilot program.

A. The Company installed 23 reclosers on five distribution circuits to develop a smart system of circuits. Fifteen of the 23 reclosers will be used as conventional reclosers in an auto loop configuration for fault clearing and circuit tie operation. These reclosers have two way communications and are available for control by the Distribution Operators and the Auto Restoration Control System. The remaining reclosers are being used as SCADA operable switches and are available for use by the Distribution Operators and the Auto Restoration Control System. In addition, 11 switched capacitor banks with smart grid controls and communications are in service and available. These devices can operate automatically, can be operator controlled and can be controlled by the centralized Coordinated Volt / Volt-Ampere Reactive ("VAR") system. Additionally, RECO installed three phase sensors on these installations to provide power quality information which is available in real time to the operators via the Company's Distribution Feeder Supervisory Control and Data Acquisition ("DSCADA") system.

Q. What is the status of the real time control systems installed by the Company as part of the SGIG pilot program?

A. The auto restoration system has been developed and the model centric software used by this control system has been tested and deemed to be working correctly and reliably. Pole mounted electronic controls that operate the field hardware have been set up in RECO's

Smart Grid Lab to test the production versions of the control system using the production SCADA system and actual communications paths.

The Company simulated distribution line faults on this test system and the model centric software successfully determined the proper means of isolating the fault and restoring the customers on the un-faulted line sections. The control system then successfully executed the isolation and restoration plan through the DSCADA system. Control commands were received by the hardware which operated successfully to clear the simulated fault and restore the un-faulted line sections. The DSCADA system itself is undergoing some final design tweaks, functionality improvements and software upgrades. Once the Company completes these final DSCADA system improvements, they will be rigorously tested and then placed into production. The achievement of that milestone will allow the Company to place the auto restoration control system into service. The current schedule projects that this milestone will be achieved by the end of the first quarter of 2014.

The model centric Volt / VAR control system was also tested in RECO's Smart Grid Lab using production systems and actual field hardware. The system worked as designed to control the voltage levels and provide VAR support to maximize efficiency by minimizing system losses. The testing demonstrated that the software successfully reduces voltage levels for conservation voltage reduction without generating customer voltage violations. The testing also revealed that additional savings could be realized by revising the software algorithm to improve system efficiency when in conservation voltage reduction mode. The Company currently is designing additional changes to this algorithm. Once complete, the revised Volt / VAR system will be rigorously tested and then placed into production. The achievement of that milestone will allow the Company to place the Volt / VAR control system into service. The current schedule projects that this milestone will be achieved by the end of the second quarter of 2014.

Q. What benefits has RECO realized from the recloser installed as part of the SGIG pilot program?

A. RECO's customers are already benefitting from these installations. Even though the Auto Restoration Control System is not yet in service, RECO placed many of the reclosers in service in a conventional automatic fault clearing mode to improve reliability and establish the remaining reclosers as DSCADA operable switches. With all reclosers communicating with the DSCADA system, the Company's Distribution System operators now have enhanced situational awareness and remote control. This allows the operator to quickly make informed decisions and build restoration plans that they can be executed remotely. This improves customer reliability and reduces system restoration time. Once the Auto Restoration control system is placed in service, it will automatically build and execute restoration plans relieving the operator of that task. This ability will further improve and expedite fault isolation and restoration, thus improving reliability and resiliency above the levels that can be achieved under direct operator control. This will provide a major benefit, particularly during storm conditions when the operator is inundated with information and is dealing with numerous system events. The Panel would note that at the time of the preparation of this testimony, RECO has not experienced any outages on the smart grid set of circuits for which the reclosers could automatically provide system restoration.

Q. Has RECO realized benefits from the capacitors installed as part of the SGIG pilot program?

A. Yes, RECO's customers are already benefitting from these installations. Prior to installing the switched capacitors, the Company performed an analysis to determine the phase swaps necessary to phase balance the circuits and phase changes were performed in the field. Additionally, the Company performed analysis to optimize capacitor location and size. Fixed capacitor banks, and switched capacitor banks of the proper size equipped with Smart Grid controls and communications were installed at the locations identified in the analysis. All switched capacitor banks were placed in service with conventional system peak based automatic control settings and are ready for coordinated Volt / VAR control. Optimizing the circuits by performing phase balancing and optimally sizing and placing the capacitor banks lowers system losses and improves system operating conditions. The coordinated Volt / VAR control once placed in service takes this to a new level by dynamically adjusting voltage profiles and VAR support across the entire year, while also reducing energy consumption through conservation voltage reduction.

Q. Did RECO bill the DOE directly for the reimbursement of costs associated with the SGIG pilot program?

A. No, RECO did not bill DOE directly. Orange and Rockland, the parent company of RECO was a sub-recipient of the SGIG that DOE awarded to Consolidated Edison Company of New York, Inc. ("Con Edison", or "CECONY"). RECO was a sub-recipient of Orange and Rockland. Con Edison billed DOE on Orange and Rockland's (and ultimately on RECO's) behalf. Once reimbursed by DOE, Con Edison would reimburse Orange and Rockland. In turn, Orange and Rockland then would reimburse RECO.

Q. Please describe briefly how CECONY Smart Grid Cost Management ("SGCM") files for reimbursement from DOE.

A. CECONY SGCM will file for reimbursement from DOE through the VIPER system (i.e., DOE's reimbursement system) for 50% of the costs accumulated in the billing projects. The application for reimbursement of costs from DOE will reflect actual costs that have been expended and directly charged to the billing project and supported by the Company's detailed accounting records. The other 50% relating to RECO's SGIG pilot program, upon the completion of each project, will be closed out to plant-in-service and be recovered from RECO's customers. .

Q. Please briefly describe the sub-recipient (RECO) billing process.

A. Billings for sub-recipients and vendor costs for reimbursement are only included in the invoicing process to DOE if the payment will be made in accordance with the terms and conditions of the subcontract or invoice and paid within 30 days of the billing for reimbursement. The sub-recipient billing process involves the following steps:

- Con Edison, as the prime-recipient of the SGIG, will submit the monthly billings to the DOE on behalf of Orange and Rockland.
- Orange and Rockland will record costs related to the projects to various billing projects. Each month, these billing projects automatically clear 50% to Capital CWIP and 50% to billing projects (the amount expected to be reimbursed from DOE).
- Each month, Orange and Rockland will submit to CECONY SGCM an invoice statement detailing the work completed, with documentation substantiating the

expenditures. This statement also will include the number of labor hours expended during the month.

- On the invoice, Orange and Rockland will verify that the expenditures are allowable under the SGIG program requirements and that the invoices have been reviewed for accuracy and confirmed to be for work that is part of the approved project scope. Orange and Rockland will retain all supporting documentation.

Q. What was the amount reimbursed?

A, Please see Exhibit __ (SGP-1).

Q. Has DOE provided approval of the reimbursement mechanisms?

A. Reimbursement guidelines were provided to and accepted by DOE.

Q. How does DOE verify compliancy for reimbursement?

A. An independent contractor (*i.e.*, Price Waterhouse Coopers, LLP) annually reviews the reimbursement filings. The contractor's findings are forwarded to the DOE officer.

Q. What were the results of the annual audits of RECO?

A. There were no major discrepancies or non-compliance issues identified throughout the grant duration.

Q. Did RECO submit quarterly reports of Smart Grid pilot program related capital expenditures to Board Staff and Rate Counsel?

A. Yes, as required by the Smart Grid Order (p. 7),[1] RECO submitted quarterly capital expenditure reports to both Board Staff and Rate Counsel. In addition, as required by the Smart Grid Order (p. 9), RECO submitted annual filings to the Board, which included the minimum filing requirements set forth in the Stipulation of Settlement adopted by the Smart Grid Order.

Q. Did RECO fill all 15 of the positions identified in Appendix A of the Stipulation adopted by the Board in the Smart Grid Order?

A. The Company hired the following eight Full Time Employees ("FTE"):

- 2 Smart Grid Engineers;
- 1 Protection/DG engineer;
- 1 Substation SCADA Systems / Equipment engineer;
- 1 DEW Administrator;
- 1 Systems Integrator/Security Administrator;
- 1 Communications Engineer; and
- 1 Technical Operations Supervisor.

In managing the cost of the SGIG pilot program, the Company decided not to fill the remaining seven positions, *i.e.*, one Meter Systems Specialist, one Systems Integrator/Security Administrator, one Field Engineer and the four Field Technician positions. The work proposed for the Meter Systems Specialist was absorbed by the two incremental Smart Grid Engineers and other engineering department personnel. The work

[1] *I/M/O the Petition of Rockland Electric Company Requesting Support for a Smart Grid Pilot Program*, BPU Docket No. ER09060459, Order Adopting Stipulation (dated April 5, 2010) ("Smart Grid Order").

proposed for the second Systems Integrator/Security Administrator was absorbed by the Systems Integrator/Security Administrator hired, supplemented by support from Con Edison Information Resources security team and cyber security consultants. The Field Engineering support was provided by a combination of the Smart Grid Engineers and other Field Engineering employees. The Company used contractors to perform the Field Technician work.

Q. Has the Company developed a cost benefit analysis applicable to the SGIG pilot program?

A. Orange and Rockland has been working collaboratively with Brookhaven National Labs ("BNL"), Electrical Distribution Design ("EDD") (a consultant based in Blacksburg Virginia), and has contracted with the Electric Power Research Institute ("EPRI"), through Con Edison, to identify and quantify tangible cost savings that can be realized from the Smart Grid concept used in the SGIG pilot program. Orange and Rockland, BNL and EDD have collectively identified some areas where tangible cost savings could be realized. Using Orange and Rockland's DEW engineering software and its Integrated System Model ("ISM"), Orange and Rockland and BNL performed detailed calculations on a system of fourteen typical distribution circuits to determine improvements in circuit efficiency that can be achieved through phase balancing and optimal capacitor sizing and placement. Using these optimized circuits, EDD then performed calculations to determine the incremental improvement in efficiency that adding a real time Coordinated Volt / VAR control system to these circuits, as was done in the SGIG pilot program, could potentially provide. EDD also performed a Conservation Voltage Reduction ("CVR") analysis on these circuits to determine what energy savings could potentially be achieved through the use of the Coordinated Volt / VAR system in CVR mode. Additionally, Orange and Rockland prepared an analysis of the effects that adding automation could have on the deferral of a major capital project. Also analyzed were the effects that automation can potentially have on storm resiliency. EPRI is reviewing all of these results, performing an economic analysis, and is preparing a report that will identify the savings from these areas. Once complete, this report will provide a qualitative measure to the value of the various methodologies and technologies used, and will monetize some of the potential tangible cost savings that can be achieved on this 14 circuit system. While all of the modeling and analysis was performed on circuits in Orange and Rockland's New York service territory, the circuits are representative of the electric distribution system that exists in RECO's service territory. As a result, the benefits identified from these various methodologies and technologies that were or will be implemented as part of the SGIG pilot program, are applicable to RECO.

Q. Please discuss RECO's 2014 Smart Grid plans for the South Mahwah and Darlington pilot project area.

A. In 2014, RECO plans to expand the system of Smart Grid circuits, which were initially developed as part of the SGIG, by one circuit pair to provide additional information in the pilot project area. The Company estimates project spending of $300,000 in capital and $30,000 in O&M. The O&M expenditure is included on Exhibit P-2 Schedule 23.

The testimony prior to this point supports the Company's efforts to date to implement smart grid and automation technology as part of the completion of the DOE SGIG pilot program. The testimony that follows represents the Company's forward looking plans and vision with respect to technology expansion and costs associated with distribution automation and smart grid. The attendant costs are not included in the base rate revenue requirement and are part of RECO's request for a Separate Surcharge/Phase II that is tied in with the Company's Storm Hardening and AMI initiatives.

Q. Please discuss RECO's plans to expand the technologies implemented and the lessons learned from the SGIG pilot program to other parts of the Company's distribution system.

A. The Company would look to target the expansion of these Smart Grid technologies to areas of its electric distribution system that show the highest cost-benefit potential. The chart below describes the current state of RECO's electric distribution circuits, with respect to existing distribution automation deployment, from both an automatic fault restoration and a coordinated Volt / VAR control perspective.

Automation Type	Number of Loop Schemes	Number of Circuits Represented	Number of Automation Devices	Devices Retrofit with SCADA communications packages not yet SCADA Commissioned	SCADA Operable Devices Under Operator Control	SCADA Operable Devices Under Smart Grid Control
Automatic Restoration						
Circuits with Midpoint reclosers	0	29	39	39	0	0
Conventional Automatic Loop Schemes	14	28	47	29	0	0
Smart Grid Enhanced Loop Schemes	5	7	27	0	27	27
Circuits with No Automation	0	28	0	0	0	0
Coordinated Voltage and Var Control						
	Total	**Number of Circuits Represented**	**Number of Devices with Automatic Controls**	**Controls Retrofit with SCADA communications packages not yet SCADA Commissioned**	**SCADA Operable Controls Under Operator Control**	**SCADA Operable Controls Under Smart Grid Control**
Substation Transformer Banks	25		21	0	21	2
Switched Shunt Distribution Capacitor Banks	97	87	97	0	9	9
Distribution Voltage Regulators	3	1	3	0	0	0

In order to expand distribution automation technology with Smart Grid functionality to all of RECO's distribution circuits, the Company would need to implement the following equipment and circuit enhancements:

- Circuits with no automation devices would pair with another circuit as part of an auto-loop, and require the addition of mid-point reclosers, a tie recloser, SCADA operable switches and SCADA operable capacitor banks;
- Circuits that already have just mid-point reclosers would pair with another circuit as part of an auto-loop, and require the addition of a tie recloser, SCADA operable switches and SCADA operable capacitor banks; and
- Circuits that are already part of an auto-loop would require the addition of SCADA operable switches and SCADA operable capacitor banks.

The estimated costs, in current dollars, for the Company to expand these distribution system automation / Smart Grid enhancements across all of its distribution circuits are shown in Table 1 below:

Table 1: RECO Cost For Full Scale Smart Grid Distribution Circuit Deployment:

Circuit Description	Circuit Pair Quantity	Cost/Circuit Pair (w/contingency)	Total Cost
Circuits currently without automation	14	$725,000	$10,150,000
Circuits currently with Midpoint Reclosers	14	$560,000	$7,840,000
Circuits currently in auto-loop configuration	14	$368,000	$5,152,000
Total			$23,142,000

RECO's proposes to spread the cost of its distribution Smart Grid expansion over 15 years, with average annual expenditures estimated at $1.55 million in capital, and $155K in Operation and maintenance expense ("O&M"). The Company proposes that these costs will be collected through the storm hardening surcharge.

In addition to the distribution system expansion, RECO is planning on incorporating advanced technology and smart grid enhancements into all future substation infrastructure projects such as the proposed Summit Avenue substation. The incorporation of advanced technology and smart grid enhancements will be addressed when the Company seeks rate recovery of the costs of these substation projects in future rate cases.

RECO presently has SCADA communications to all of its substations in its service territory. Many of RECO's substations have Smart (*i.e.*, microprocessor based) relays, smart annunciators and auto-transfer schemes in dual bank stations, and many have fiber communications at or near the substations. As substations are upgraded, the Company plans to convert existing copper communications paths to fiber optics to improve communications bandwidth and functionality, and reduce reliance on less-reliable external networks.

As the Company adds new substations, or undertakes upgrades of its existing stations, many new substation-based Smart Grid technologies will be deployed to create a more resilient and faster healing Grid. By utilizing new monitoring systems, automation technologies, and communications abilities, RECO can better optimize operation of the electric system to improve awareness and operational response to major system events such as storms. These smart technologies will provide improved awareness and clarity of the status of electric equipment in the substation and of the Grid as a whole, all in near real-time. These new smart technologies include:

- A new substation server which functions as the data center of the substation and provides advanced automation functions, including:
  - ✓ Automatic-transfer scheme for fast customer restoration in the event a single transformer is lost.
  - ✓ Centralized data collection point for intelligent electronic devices such as relays, meters, transformer monitors, breaker monitors, cable monitors, and dynamic ratings systems.
  - ✓ Automatic fault record retrieval from substation protective relays and subsequent file transfer to the Company's ECC servers for post-event analysis. This near real-time generation and transfer of fault records to the ECC saves valuable time when performing system restoration by expediting the relevant data to engineers and system operators.
  - ✓ Direct connection to data historian servers that will provide a wealth of engineering data for analysis. Previously, most non-critical substation data was trapped in the substation.

- Installation of transformer and breaker diagnostic equipment for routine equipment monitoring will improve the reliability of the major components in the substation. The new transformer diagnostic systems monitor transformer winding hot spots, oil temperatures, tap position, and LTC motor current. A relay-based breaker monitoring system will identify breaker timing issues and wear. The diagnostic equipment will identify incipient faults in the units, better protect equipment from failure, and reduce adverse impact to customers from service interruptions. Benefits also include the advanced monitoring of equipment in real-time which allows for dynamic ratings achieved through the analysis of real-time operating temperatures. The monitoring systems also serve as the basis for implementation of a condition-based maintenance schedule, rather than the current time-based maintenance schedule.
- Fiber-optic communications networks increase bandwidth and improve the speed and quality of the data transferred between the substation and the ECC. Additionally, fiber optic connections to the substation allow for greater amounts of information to be brought back to the ECC for analysis, *i.e.*, eDNA and fault record retrieval.
- Time synchronization of all protective relays and control system equipment via a GPS clock will provide time stamping capability of data from the individual electronic devices within the substation. This will allow for a more precise analysis of system events and disturbances, *i.e.*, faults.

Q. Will RECO require additional full time employees to design, operate and maintain these new technologies, systems and equipment associated with advance automation, distribution system management and smart grid technology implementation as part of a daily and sustainable business model?

A. Yes. The Company will need additional employees in its Engineering, System Operations and Electric Operations organizations to provide a viable and sustainable workforce to design, operate and maintain all of these new technologies, equipment and systems that constitute incremental and growing workload. RECO will need to add six full time employees for engineering design and systems development, three for System Operations control room oversight and operating support, and five for Electric Operations field construction and maintenance support.

Q. Please describe the need for additional Engineering employees.

A. The following describes the Company's need for six full time employees for engineering design and systems development.

<u>Distribution SCADA Engineer</u>

RECO is requesting one DSCADA engineer. Since 2008, just prior to the SGIG pilot program, RECO was in the process of obtaining and installing a Distribution SCADA system and retrofitting existing field devices with communications. Since that time, all existing field reclosers have been retrofit with communications and are in the process of being commissioned for use by the DSCADA system. One Distribution SCADA engineer has been dedicated full time to set up and testing of the DSCADA system. In December 2012, the Distribution SCADA System became functional and is now being used by the Distribution Operators for both situational awareness and for remote control of field devices. Work on the system continues with tailoring of the system within the framework of the software to better suit operator needs, working with the vendor on bug fixes and enhancements, working on machine to machine data communications issues, preparing one screen one line diagrams and updating databases as new field devices are added and field devices retrofit with communications packages are commissioned and providing back office support for field crews when SCADA commissioning field devices. The work associated with the five circuits, implemented as part of the SGIG pilot program, alone added 23 reclosers, and eleven capacitor banks to the system totaling 34 additional devices. Extensive testing requirements for patches and new releases are required and are frequent and time consuming. Additionally, day to day requirements such as system and security updates, maintenance and upkeep of the operator work stations and all of the other ancillary equipment also requires a significant amount of the DSCADA Engineers time. When taken in aggregate, this ongoing work exceeds what can reasonably be expected to be handled by one person. Additionally, the need to provide round the clock availability of the DSCADA system has risen as the system becomes more heavily relied upon to provide the situational awareness necessary to reduce extended customer outages and improve outage restoration time. With one DSCADA engineer, round the clock availability is simply not possible. Also, with the system being promoted from a setup and testing phase into a production environment, there is significant risk with having a system rising to critical status maintained by a single person. Should that person no longer be available for any reason, a failure of the DSCADA system could conceivably take days or longer to recover from and all situational awareness and remote control of the field devices will be lost during that time. All of the above demonstrates the need for a second DSCADA engineer to share in the expansion, upkeep testing and enhancement of the system.

Systems Analyst; and Information System Manager

Specialized Engineering systems such as the DEW Engineering System, the Integrated System Model, and real time systems such as, the Distribution SCADA system, the DEW Auto Restoration system and the DEW Coordinated Control system are not supported by the corporate Information Resources ("IR") department. Rather, the designs, development and maintenance of the systems, servers, switches, networks and equipment used by these systems is the responsibility of the user department. RECO has hired an information technology professional within the Smart Grid Engineering group to develop the architecture, and install operate and maintain these systems with the support of vendors and consultants. In order to provide the necessary Company resources to adequately address the expanding workload surrounding the systems mentioned above, RECO is requesting to add one Systems Analyst and one Information Systems Manager.

The DSCADA system, DEW Engineering system, DEW Auto Restoration and DEW Coordinated Volt-VAR systems have complex architecture with many interfaces to different systems that reside on both the corporate local area network and the high value cyber secure networks. The networks and interfaces were designed and are being built by a single Senior Systems Analyst working with the aid of consultants and vendors. As the system of networks and interfaces develops and is being placed into production, the volume of work has exceeded the capabilities of a single Senior Systems Analyst, and the backlog of important development work is increasing, thereby slowing the development process. Having only one Senior Systems Analyst responsible for a system of this scope and importance is a significant risk. Should this individual not be available and an issue develop the resolution will be prolonged and will adversely affect system availability. These systems are quickly becoming critical 24 x 7 operating systems, and the additional Senior Systems Analyst position in addition to relieving the work backlog is necessary to mitigate operating risk. In view of these issues, RECO proposes to add a second Senior Systems Analyst for its Smart Grid Engineering group.

The Smart Grid Engineering group has two distinct sections, an IR section and an Engineering section. In addition to the IR responsibilities described above, the IR section is also responsible for cyber security on the high value DSCADA system real time network, where the DSCADA system and the DEW real time control systems reside, as well as data communications between the field devices and the DSCADA system. A hardware/Network specialist position was established and is being filled to address the needs associated with managing the servers, switches and network connections. Up to this point the Department Manager of Smart Grid Engineering has been project managing the IR work. He also has been managing all of the engineering duties the Smart Grid Engineering department is responsible for including Distribution Automation equipment installations, DSCADA field equipment commissioning, Distribution Automation equipment maintenance and repair, Distribution Automation Equipment Specification development, Lab testing of new equipment, Smart Grid deployment, radio communications with the field devices, distribution protection, power quality and distributed generation interconnections. The Company has reached the point in IR system development and implementation where there is more than can be effectively managed by the Department Manager (who is not an IR professional) along with all of his other responsibilities. In order to effectively manage a section of this size and importance a dedicated IR Manager position is required. Accordingly, RECO is requesting to add an IR Manager to its Smart Grid Engineering Department.

<u>Smart Grid Engineers</u>

Currently, the engineering section of the Company's Smart Grid Engineering Department has the following six engineers: one DSCADA engineer, one Distribution Automation Engineer, one Smart Grid engineer focusing on field device communications, one Smart Grid Engineer focusing on, equipment sizing, placement, specification, installation, setup and commissioning, one DEW Engineering System Administrator, and one Engineer responsible for Distribution Protection, Power Quality and Distributed Generation. The SGIG pilot program allowed RECO to build the core department necessary to design, engineer and maintain the backbone infrastructure systems that will be used for the expansion and to implement the five circuit Smart Grid pilot project. The expansion of

Smart Grid across the Company's service territory will build upon this work and requires two additional Smart Grid Engineers who will focus on equipment sizing, placement, specification, installation, setup and commissioning.

A supplementary benefit for these two additional positions are the roles they will assume as crew leaders and system analysts during emergencies and major storm events that will substantially enhance the Company's capability to provide improved response and system restoration during these events.

Protection/Distributed Generation/Power Quality Engineer

This position is responsible for the design, review, and issuance of protection schemes as required on the electric distribution electric system including all automation and smart grid installations. Responsibilities also include the processing, approval and witness testing all new customer distributed generation systems and completing all power quality studies and investigations.

The recent development of the DSCADA system, and substantial deployment of the Company's automation and Smart Grid Systems, has increased the amount of protection settings and coordination studies that will need to be completed in order for these systems to be placed online and operate properly. The continued advancement of smart grid systems with advanced electronics have resulted in increased technical engineering reviews, which include designing more elaborate protection schemes, increased development of end user training procedures, and more complex event analysis. Additionally, the workload with respect to the interconnection of distributed generation ("DG") has expanded at an unprecedented rate. The number of DG sites (particularly photovoltaics) on the distribution system has continued to double each year over the past three years due to reduced technology costs that are resulting in shorter paybacks, reduced system interconnection costs, and state incentive programs. These numerous requests have to be processed, reviewed, and approved in very specific regulatory timeframes. These require detailed voltage studies so that they do not cause power quality issues and customer complaints on the distribution system, and also require numerous site visits to inspect systems and witness and approve interconnection testing. The proliferation and continued expansion of these technologies interconnecting with the electric delivery system will continue to increase this workload.

Q. Please describe the need for additional System Operations personnel.

A. RECO's Distribution Control Center ("DCC") is located within the Company's ECC, and is responsible for the real-time operation and oversight of the Company's distribution system. The primary operating authorities that oversee and control the system on a daily basis are Control Authorities for All Distribution ("CAAD"). The CAAD controls all safety setups for lineman working on the distribution system, and through coordinated switching, control the energizing and de-energizing of the distribution lines. The Company presently has seven CAADs that operate within a 24/7 shift schedule. The Company's implementation and expansion of automation and Smart Grid technology is creating a substantial and incremental workload for the CAADs with respect to the need for increased training, job knowledge, and expanded operational awareness and system oversight. Based on these expanding and incremental responsibilities, RECO has determined that the DCC will require three additional CAADs.. The additional CAAD positions will be strategically scheduled to assist covering the most active times of day. The CAAD position affects all aspects of Operations during normal operations, and their impact to effectively manage the system and restoration recovery efforts escalates during emergency. Through comprehensive job task analysis, the Company has determined that on average the CAAD has 17 hours of work for each 12 hour day. As a result the CAAD's situational awareness is compromised with each additional task that is required. The expansion of responsibilities to operate the DSCADA system and the new field technologies creates additional tasks and efforts to manage, oversee and realize the attendant benefits offered. The continued introduction of DSCADA Technologies into the Company's distribution system will increase the daily tasks of the CAAD. From pre-work switching and clearance setups to DEW situational awareness and alarm responses, the CAAD's roles and responsibilities are increasing exponentially. A supplementary benefit to additional CAADs is the improved management and control room oversight that will be available during emergency and storm events. The CAAD is the heartbeat of the Company's response to emergency and storm events. Unsafe situations, customer restoration, and communication about these situations emanate from the CAAD and their role during emergency and storm situations. These additional CAADs will maximize the use of DSCADA systems during emergency situations and facilitate the safe and reliable operation of the system on an everyday basis.

Q. Please describe the need for additional Electric Field Operations personnel.

A. RECO will need to add four Distribution Equipment Technicians to support the expansion of the Company's smart grid objectives and perform the necessary field work associated with the installation, testing, commissioning, inspection and maintenance of all IEDs. The devices include switched capacitor banks, automated switches, reclosers, as well as associated monitoring and communications equipment. In addition, the Distribution Equipment Technicians will respond to system emergencies and support emergency restoration efforts and public safety during these events.

In addition, RECO is proposing to add one Equipment Technician Supervisor to manage the additional Equipment Technicians. This position will be responsible for the supervision and assignment of work to crews for all activities associated with construction, installation, maintenance, removal, repairs, operation and inspection of the IED's. In an effort to continue to comply with the ever changing technology, this position will be required to develop internal policies and guides for the group, as well as, address training requirements for field personnel. Furthermore, this Supervisor will be required to respond to system emergencies and be assigned accordingly to support safety and restoration efforts during these events.

Q. What are the expected costs and timing of these additional Engineering, System Operations and Electric Operations resources?

A. The Company proposes to add these resources in the first quarter of 2015, at the same time it proposes to implement its storm hardening and system resiliency programs and plans. The range of salaries for these positions is anticipated to be between $90,000 and $125,000, and will have varying capital and O&M cost splits. These positions will be shared between Orange and Rockland and RECO. Therefore, RECO will be allocated its share of the O&M component of these salaries (typically in the 25% to 30% range). The capital portions of these salaries will be charged directly to the capital infrastructure projects that are being worked.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Exhibit_(SGP-1) - NJ Smart Grid Pilot Project Cost Breakdown

RECO NJ SMART GRID THREE-YEAR PILOT PROJECT

DISTRIBUTION SYSTEM COSTS						**Actual Costs By Year**		
Equipment	**Original Forecast (from STIP)**	**Reforecast (2nd quarter 2012)**	**Variance / Explanation**	**Actual Cost**	**Planned DOE Reimbursement**	**Year 1 (2010) Actual Cost**	**Year 2 (2011) Actual Cost**	**Year 3 (2012-13) Actual Cost***
Distribution Circuit Modifications	$ 79,800.00	$ 79,800.00	Project variances due to increased distribution costs realized after final engineering and design, as well as increase fringe and overhead costs on the distribution equipment installation.	$ 139,717.63	$ 69,858.82	$ 5,440.02	$ 134,277.61	$ -
Automation Equipment	$1,182,874	$ 1,182,874.00		$ 3,270,096.81	$ 1,635,048.41	$ 1,417,430.86	$ 1,560,416.17	$ 292,249.78
Communications Equipment	$ 288,385.00	$ 288,385.00		$ -	$ -	$ -	$ -	$ -
Subtotal Equipment	$ 1,551,059.00	$ 1,551,059.00		$ 3,409,814.44	$ 1,704,907.22	$ 1,422,870.88	$ 1,694,693.78	$ 292,249.78
Total Labor, Fringe, and OH's	$5,066,091	$ 5,066,091.00		$ 3,582,214.94	$ 1,791,107.47	$ 979,368.00	$ 1,505,843.57	$ 1,097,003.37
Total Distribution Costs	**$ 6,617,150.00**	**$ 6,617,150.00**	**$ (374,879.38)**	**$ 6,992,029.38**	**$3,496,015**	**$ 2,402,238.88**	**$ 3,200,537.35**	**$ 1,389,253.15**
SUBSTATION SYSTEM COSTS								
Darlington and South Mahwah Substation Upgrades								
Equipment	**Original Forecast (from STIP)**	**Reforecast (2nd quarter 2012)**	**Variance / Explanation**	**Actual Cost**	**Planned DOE Reimbursement**	**Year 1 (2010) Actual Cost**	**Year 2 (2011) Actual Cost**	**Year 3 (2012-13) Actual Cost***
Tranformers	$ 1,800,000.00	$ 1,800,000.00	Project variances offset by increase in equipment costs and decrease in company labor usage, as well as cost savings on the 138kV Underground Intrastation Tie materials.	$ 1,783,500.00	$ 891,750.00	$ 629,753.85	$ 1,153,746.15	$ -
Switchgear	$ 1,000,000.00	$ 1,000,000.00		$ 1,181,001.99	$ 590,501.00	$ -	$ 1,181,001.99	$ -
Other Equipment/Steel	$ 326,400.00	$ 326,400.00		$ 1,342,077.16	$ 671,038.58	$ 28,058.25	$ 430,271.09	$ 883,747.82
Smart Grid Equipment/Diagnostics	$ 332,000.00	$ 332,000.00		$ 53,781.50	$ 26,890.75	$ -	$ -	$ 53,781.50
Subtotal Equipment	$ 3,458,400.00	$ 3,458,400.00		$ 4,360,360.65	$ 2,180,180.33	$ 657,812.10	$ 2,765,019.23	$ 937,529.32
Total Labor, Fringe, and OH's	$ 4,438,140.00	$ 4,438,140.00		$ 3,129,788.59	$ 1,564,894.30	$ 141,543.65	$ 890,171.63	$ 2,098,073.31
Other Associated Projects								
138kV Underground Intrastation Tie	$ 813,773.00	$ 813,773.00		$ 451,145.90	$ 225,572.95	$ 9,046.07	$ 219,900.84	$ 222,198.99
Underground Distribution Circuit Exits	$ 1,715,312.00	$ 1,715,312.00		$ 1,635,045.63	$ 817,522.82	$ 28,274.34	$ 1,374,804.57	$ 231,966.72
SM Overhead Distribution Circuit Exits	$ 300,192.00	$ 300,192.00		$ 496,162.05	$ 248,081.03	$ 1,824.95	$ 482,675.37	$ 11,661.73
Total Other Project Costs	$ 2,829,277.00	$ 2,829,277.00		$ 2,582,353.58	$ 1,291,176.79	$ 39,145.36	$ 2,077,380.78	$ 465,827.44
Total Substation System Costs	**$ 10,725,817.00**	**$ 10,725,817.00**	**$ 653,314.18**	**$ 10,072,502.82**	**$ 5,036,251.41**	**$ 838,501.11**	**$ 5,732,571.64**	**$ 3,501,430.07**
COMMUNICATIONS SYSTEM COSTS								
Equipment and Field Labor	**Original Forecast (from STIP)**	**Reforecast (2nd quarter 2012)**	**Variance / Explanation**	**Actual Cost**	**Planned DOE Reimbursement**	**Year 1 (2010) Actual Cost**	**Year 2 (2011) Actual Cost**	**Year 3 (2012-13) Actual Cost***
A) Fiber & Microwave Infrastructure	$ 1,520,000.00	$ 1,878,070.00	The variance source is a result of an increase in communications equipment required to meet the Company's Corporate Cyber Security standards.	$ 1,412,992.96	$ 706,496.48	$ -	$ 423,207.00	$ 989,785.96
B) Communications and Ancillary Equipment	$ 75,516.00	$ 163,682.00		$ 102,157.48	$ 51,078.74	$ 14,630.64	$ 4,467.63	$ 83,059.21
C) Diverse Hub Site and Equipment	$ 318,887.00	$ 350,781.00		$ 996,332.56	$ 498,166.28	$ 7,031.01	$ 306,231.52	$ 683,070.03
Subtotal & Field Work	$ 1,914,403.00	$ 2,392,533.00		$ 2,511,483.00	$ 1,255,741.50	$ 21,661.65	$ 733,906.15	$ 1,755,915.20
Carrier Lease Costs	$ 115,250.00	$ 115,250.00		$ -	$ -	$ -	$ -	$ -
Total Communications Cost	**$ 2,029,653.00**	**$ 2,507,783.00**	**$ (481,830.00)**	**$ 2,511,483.00**	**$ 1,255,741.50**	**$ 21,661.65**	**$ 733,906.15**	**$ 1,755,915.20**
Total Electric Delivery System Costs	**$ 19,372,620.00**	**$ 19,850,750.00**	**$ (203,395.20)**	**$ 19,576,015.20**	**$ 9,788,007.60**	**$ 3,262,401.64**	**$ 9,667,015.14**	**$ 6,646,598.42**

*** 2013 data current thru September**

DOE Reimbursement to Date **$9,441,148.06**

ROCKLAND ELECTRIC COMPANY
DIRECT TESTIMONY OF
STORM HARDENING PANEL

Q. Would the members of the Storm Hardening Panel ("Panel") please state your names and business addresses.

A. (Meyers) Glenn S. Meyers and my address is 390 West Route 59, Spring Valley, New York 10977.

(Banker) Wayne A. Banker and my address is 390 West Route 59, Spring Valley, New York 10977.

Q. By whom are you employed, in what capacity, and what are your backgrounds and qualifications.

A. (Meyers) I am employed by Orange and Rockland Utilities, Inc. ("Orange and Rockland"), the parent company of Rockland Electric Company ("RECO" or the "Company"), as General Manger of Electric Operations. I received a Bachelor of Arts degree in 1984, a Bachelor of Science degree in Mechanical Engineering in 1985 and a Master of Science degree in Industrial Engineering in 2000, all from Columbia University in New York, New York. I have worked at Orange and Rockland for 18 years, as well as for seven years at Consolidated Edison Company of New York, Inc. ("Con Edison"). The majority of my career has been in Electric Operations, as a Control Center Supervisor, Divisional Field Engineer, Manager in Line Technical Services, and in my current position as General Manager of Electric Operations.

(Banker) I am employed by Orange and Rockland as Chief Engineer of Distribution Engineering. I received a Bachelor of Science degree in Electrical Engineering in 1991 from Clarkson University in Potsdam, New York and a Masters of Business Administration in 2000 from Iona College – Hagan School of

Business, in New Rochelle, New York. I am a registered professional engineer in the State of New York. I have worked for Orange and Rockland as an underground Distribution & Transmission Engineer, as Divisional Field Engineer for Electrical Operations Department, and my present position as Chief Distribution Engineer for Distribution Engineering Department.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of our testimony is to present and support RECO's proposed incremental Storm Hardening initiatives along with the proposed incremental personnel requirements necessary for the Company's Electrical Engineering and Operations organizations to implement these initiatives effectively.

Incremental Storm Hardening Program

Q. Does RECO satisfy its obligations regarding the provision of reliable service?

A. Yes. The Company fully meets the statutory requirement to provide safe, adequate and proper service to its customers. Nonetheless, it continues to explore ways to further enhance service reliability, as well as harden certain infrastructure and improve system resiliency when major weather related events affect the Company's service territory.

Q. Please discuss how the Company developed its proposed storm hardening initiatives.

A. After the major storms of 2011 (*i.e.*, Hurricane Irene and the October Snowstorm) and Superstorm Sandy in 2012, the Company, in February 2013, formed a team to explore methodologies and alternatives focused on improving storm hardening and system resiliency. The mission of the team was to identify opportunities to improve storm reliability on RECO's electric system and make recommendations for improvements, considering costs and other critical factors. The overall Storm Hardening team divided into five sub-teams, consisting of subject matter experts from Operations and Engineering. These sub-teams focused for six months on analyzing opportunities in the following areas: undergrounding, automation and circuit reconfiguration, system materials and construction standards, system maintenance, and vegetation management.

The high-level conclusions and recommendations of these sub-teams are discussed below.

Undergrounding Team

The Undergrounding team was formed to determine if installing facilities below ground, as opposed to overhead, can provide a cost-justifiable, hardening or resiliency benefit. Considering the expense of undergrounding, the team targeted conversion of overhead where it would prove most beneficial. In addition to existing construction, the team examined the current design practice for new substation exits to determine if it meets storm hardening requirements.

The Undergrounding team analyzed existing double circuit construction, storm-damage- prone circuits, and critical transportation crossings. The team recommended the following:

- Where feasible, eliminate and/or reduce double circuit construction supplying common load areas;
- Install new underground exits to a point of path independence;

- Selectively underground portions of double circuits with a history of storm damage;
- Evaluate critical road crossings; and
- Selectively use spacer cable systems.

While not recommended, the team considered converting the Company's entire distribution system to underground. The team concluded that this effort would be cost prohibitive, could not be completed in a reasonable amount of time, and would involve challenges with other stakeholders that customers would not embrace. The team also considered eliminating double circuit construction completely and found that a targeted approach would be more prudent; some double circuits have minimal tree exposure and the exposure in certain circumstances is lower. The probability of success of each of the Undergrounding team's recommendations is high and the intuitive hardening benefit is proven.

Automation and Circuit Reconfiguration Team

Automation has proven to be one of the most effective solutions in enhancing system resiliency. The Automation and Circuit Reconfiguration team reviewed the application and design standard of existing automation technologies on the Company's distribution system and explored new technologies available for mainline and spur automation. The team also explored ways to improve circuit configuration with alternative design oriented solutions.

After analyzing the Company's distribution system to identify areas where increased automation would have the greatest resiliency benefit, the Automation and Circuit Reconfiguration team recommended the following:

- More prolific use of reclosing devices;
- Use of SCADA load break switches on main lines;
- Strategic use of single and three phase spur automation;
- Auto loop design standard enhancements;
- Segment customer count and distance reduction; and
- Improve restoration capability by closing single and three phase gaps on the overhead distribution system.

<u>System Construction Team</u>

The System Construction team looked for opportunities to both harden the system and make it more resilient. The team investigated whether the system can be constructed to more effectively reduce storm related outages and if there are construction methods available that would allow for continued operation if damage occurs.

The System Construction team reviewed the benefits of moving to National Electrical Safety Code ("NESC") Grade B construction, reconstructing double circuit distribution pole lines to minimize customer exposure, using aerial cable construction, using spacer cable construction, using breakaway connectors, upgrading feeders to 900 amps, using composite poles, modifying pole loading calculations using 1" of ice vs. ½", which is the NESC standard for heavy loading districts, and changing the size of guy wire to strengthen the system.

After exhaustive analysis, the team made a number of recommendations. The System Construction team recommended that the Company maintain the distribution system, as a general matter, at its current grade C construction. However, for critical poles such as major equipment poles, high use junction poles or transportation crossings, the team recommended that a move to a higher grade construction by increasing pole size and strength may be warranted. With regard to double circuit poles, the team recommended that reconstruction be considered on a case by case basis. There are many options and the best alternative depends on system conditions at specific locations. The use of breakaway connectors will be limited, and installed as part of a pilot program; the technology is not mature enough to install on a broader scale. Composite poles will also be used on a limited basis as part of a pilot program. While the poles may provide some hardening benefit, there are other issues to consider, such as the ability for other parties to attach their facilities.

<u>System Maintenance Team</u>

The System Maintenance team evaluated the Company's existing maintenance programs to determine if opportunities exist to make the electric delivery system less susceptible to storm damage or improve the Company's ability to recover from damage resulting from a storm event.

The Company's electric 138kV and 69kV high voltage system is primarily an overhead system with almost 80% of the structures constructed from wood components. Wood is an efficient, readily available and cost effective construction material. However, it is a natural material vulnerable to the weather and subject to attack from insects and animals. The majority of defects and failures on the electric delivery system result from decay and destruction by natural forces. Orange and Rockland can harden its system by replacing wood components with steel, particularly where practical on its high voltage system. In areas where the shoreline has eroded pole foundations, thereby compromising poles' strength as part of the original design, stream bank stabilization efforts are undertaken to restore the ground to a safe condition. Other recommendations, such as the purchase of wetland matting, are the result of the difficulty in accessing some facilities in order to make repairs during storms.

Aggressively inspecting and replacing poles that are defective provides a benefit during storms, where survival of defective poles is scarce.

<u>Vegetation Management Team</u>

The Vegetation Management team was formed to review the Company's existing vegetation management programs and practices to determine if opportunities exist to make the electric delivery system less susceptible to storm damage caused by vegetation contact.

As previously noted, the Company's electric system is primarily an overhead system situated in heavily treed areas. This potential conflict with local vegetation is an exposure that has been mitigated through aggressive pruning and tree removal. The vegetation management that the Company has completed over several previous maintenance cycles has increased the aerial space between vegetation and live conductors and reduced the number of tree-caused outages. While performance has improved, there are further opportunities to improve reliability by targeting certain vegetation management practices.

The Vegetation Management team identified the following opportunities:

- Expanded clearance standards for the mainline conductors from the substation to the circuits first mainline protective device;
- Enhanced hazard tree program;
- Use of branch reduction techniques;
- Conduct an urban tree health study;
- Perform an off –right-of–way ("ROW") hazard tree survey; and
- Target enhancements to municipality-identified critical infrastructure.

Q. Is the Company proposing to undertake any new programs to enhance service reliability in its service territory?

A. Yes, the Company is proposing to initiate Incremental Storm Hardening and System Resiliency Programs that will provide its customers with an enhanced level of service reliability throughout the year and particularly during major weather-related events.

Q. Why is RECO proposing these new programs?

A. Customers continue to place a greater reliance than ever before on electricity for highly specialized uses (such as computers, security systems, high definition flat screen televisions, broadband access equipment (*e.g.*, modems), automatic garage door openers, timers for outdoor and indoor lighting, clock thermostats, automatic sprinkler systems, and other programmable devices), even and particularly during times of major weather related events. Greater dependence on these high tech applications has made the Company's customers less tolerant of service interruptions. To meet its customers' evolving needs, the Company has evaluated measures that can be taken to reduce further even the present low number of service interruptions.

Q. Please describe the additional incremental Storm Hardening and System Resiliency Programs that the Company is proposing.

A. Consistent with the conclusions and recommendations of the Company's Storm Hardening team as discussed above, this incremental program will be utilized to further storm harden targeted portions of the Company's electric delivery system from the effects from major storms. Specifically, the Company proposes to implement the following:

- Enhanced Construction Methods;
  - Selective Undergrounding;
  - Enhanced Overhead System Construction;
  - Enhanced Transportation Crossings;
- Substation Flood Mitigation;
- Enhanced Vegetation Management; and
- Accelerated Pole Reinforcement.

These additional incremental Storm Hardening and System Resiliency Programs are described in more detail below.

<u>Selective Undergrounding</u>

The selective undergrounding program will replace with underground construction one of the circuits from an existing overhead double circuit distribution corridor that has a history of higher exposure to outage incidents.

This proposed plan will install approximately three miles of selective undergrounding each year. Such selective undergrounding should serve to decrease customer outages, shorten outage duration, and help to avoid outages resulting from major storm events, in a cost effective manner. The Company envisions this as a program that will be ongoing for at least a 20- to 30-year period.

Enhanced Overhead System Construction

Storm resilient, enhanced overhead system construction alternatives, such as spacer cable systems, will be installed in targeted applications to replace conventional construction, as well as fill in gaps to create new circuit ties in the overhead distribution system that will provide hardening and system resiliency in a combined solution. Filling in gaps and establishing new circuit ties reduces the amount of radial distribution and provides a more storm resistant overhead system. This should improve the resiliency of the distribution system and allow for reduced outage durations and outage avoidance. The Company envisions this as a program that will be ongoing for at least a 20- to 30-year period.

Enhanced Transportation Crossings

This program will address distribution crossings of major highways, railroads, and waterways with more storm resistant systems. Existing transportation crossings will be upgraded with poles that are capable of withstanding higher wind loads or replaced with total underground systems where this type of upgrade makes sense. Reinforced and updated equipment typically means less damage incurred, which reduces customer outages. It also improves the availability of emergency routes during storm conditions. The Company envisions this as a program that will be ongoing for at least a 20- to 30-year period.

Q. What is the projected cost and timing of implementing these enhanced construction method storm hardening programs?

A. The Company is proposing to implement storm hardening projects in 2014. Projects presently anticipated for construction will include both undergrounding of existing overhead facilities and alternative overhead construction projects. In 2014, the Company estimates spending of $3.2 million in capital and $250,000 in operation and maintenance ("O&M") costs. These O&M costs are reflected in Exhibit P-2, Schedule 23, and are part of the $700K in total O&M costs shown in that exhibit. Full scale implementation of these enhanced construction method storm hardening programs will commence in 2015. The Company projects the total cost for these storm hardening programs will be $8.0 million annually, of which, $7.5 million will be capital expenditures and $500,000 will be operation and maintenance (O&M") costs.

Q. How does the Company propose to recover the costs associated with its proposed full scale Enhanced Construction Methods program to commence in 2015?

A. The Company proposes to recover these costs through the Company's proposed storm hardening surcharge.

<u>Substation Flood Mitigation</u>

Q. Please discuss the Company's proposed Substation Flood Mitigation Program.

A. After the major storms, the Company formed a team to identify opportunities to mitigate storm water damage to substation facilities within known Federal Emergency Management Agency ("FEMA") flood zones. The team performed an assessment of all substations located in the RECO service territory which lie within, or near FEMA flood zones and have historically had storm water intrusion. The team found that two stations, *i.e.*, Cresskill and Upper Saddle River, are geographically within or near FEMA flood zones. In the past, these two substation have experienced minor flooding, but not to the extent where that flooding has affected any live equipment or continuity of service. In an effort to improve storm reliability on the Company's electric system, while considering costs and other critical factors, the team developed recommendations using best practices from benchmarking studies, and by working with internal and external stakeholders. Specifically, the team proposed a flood mitigation solution which is designed to divert and keep flood water out of these substations in order to maintain continuity of service. The product proposed is known as Muscle Wall Flood and Containment Solution ("Muscle Wall"). Muscle Wall was chosen for a number of reasons including;

- Ease in setting up and requires far fewer workers than sandbags. The product obviates the need for sandbagging, thus freeing up personnel for other disaster activities.
- Muscle Wall's lifecycle costs are far below that of sandbags, which have a one-time use. This frees up disaster funds for other uses.

- After absorbing surface waters and chemicals, sandbags require special handling and disposal. Muscle Wall eliminates such a need, and because it is made of recyclable materials, it has a minimal environmental footprint.

Muscle Wall can be pre-positioned at strategic locations and quickly deployed wherever needed. The Company proposes a one-time cost of $300,000 in capital and $50,000 in O&M to be spent in 2015.

Q. How does the Company propose to recover the cost of its proposed Substation Flood Mitigation program?

A. The Company proposes to recover this cost through the Company's proposed storm hardening surcharge.

Enhanced Vegetation Management Program

Q. Please discuss the Company's proposed enhanced Vegetation Management Program.

A. The Company proposes to increase funding to cover the additional vegetation work proposed to harden the electric delivery system and improve reliability during damaging storms. The funding will cover the added costs of widening the Company's trim zones on a portion of the circuit mainline from the substation to the first mainline protective device, and additional work required for "branch reduction." The branch reduction work is based on a joint utility study through the Electric Power Research Institute ("EPRI"), which identified the pivot angle and leverage impact of large tree limbs that normally would not be trimmed during vegetation maintenance. This work has been added to the Company's vegetation management program and has resulted in incremental costs. The work focuses on limbs >6” in diameter that overhang the conductors and would not normally be cut. These are now being cut to enhance tree health and lessen risk to the electric delivery system. The program targets areas where the greatest exposure exists for large customer outages. An expanded danger tree and hazard tree program will require additional funding as well. Resources need to be dedicated to aggressively patrol the electric delivery system to identify hazard trees, tracking tree locations, and interacting with customers to remove these hazard and danger trees. The urban tree assessment will identify and manage danger trees. The Company requests incremental staffing to oversee and manage the expanded vegetation management program.

A separate request has been submitted for a generalized off-ROW hazard tree assessment and for specific Ringwood area improvements. Despite efforts to clear incompatible vegetation from the ROWs, the potential exists for off-ROW vegetation to impact the system. In some areas, ROWs are narrow, making the off-ROW trees more threatening to RECO’s system. Efforts have been made to improve reliability in the Ringwood area. However, the area continues to be problematic and perennial contains the poorest performing circuits. A targeted effort to reduce vegetation exposure in Ringwood will improve reliability to the Ringwood customers.

A request has been submitted for funding for an independent review of our high voltage system and electric delivery system vegetation management programs.

These independent program reviews are expected to identify high risk areas on which to focus further hardening efforts.

Q. What is the projected cost and timing of implementing the Company's proposed enhanced Vegetation Management Program?

A. The Company is proposing to implement vegetation management program enhancements in 2014. Enhancements presently anticipated will include targeted vegetation management in the Ringwood area, and funding to commence a Hazard Tree identification and tracking program as requested by the Board of Public Utilities. In 2014, the Company estimates spending of $250,000 for the Ringwood project, and $200,000 for the Hazard Tree programs, all O&M. These O&M costs are reflected in Exhibit P-2, Schedule 23. Full scale implementation of the enhanced Vegetation Management Program will commence in 2015. The Company projects the total increased operation and maintenance costs associated with this Program will be $900,000 annually.

Q. How does the Company propose to recover the costs associated with its proposed full scale enhanced Vegetation Management Program to commence in 2015?

A. The Company proposes to recover these costs through the Company's proposed storm hardening surcharge.

<u>Accelerated Pole Reinforcement Program</u>

Q. Please discuss the Company's proposed Accelerated Pole Reinforcement Program.

A. The Company proposes to increase funding to support incremental costs associated with the replacement of defective poles. The program is required to accelerate the replacement of poles identified as defective during the inspection process. There are 41,600 poles in the RECO service territory with 91.3% inspected since 2004. The reject rate for these poles is 7.23%. 2,101of these poles required trussing at $500 per pole, and 645 required replacement at $6,000 per pole. Approximately 300 poles remain to be trussed and 140 remain to be replaced.

Q. What is the projected cost of implementing the Company's proposed Accelerated Pole Reinforcement Program?

A. The Company is proposing to commence the implementation of the Accelerated Pole Reinforcement in 2015. The Company projects the total costs associated with this Program will be $330,000 annually for a three year period. This will be comprised of pole trussing capital costs of $50,000 annually, and $280,000 for pole replacement (*i.e.*, $196,000 capital and $84,000 O&M).

Q. How does the Company propose to recover the cost of its proposed Accelerated Pole Reinforcement Program?

A. The Company proposes to recover this cost through the Company's proposed storm hardening surcharge.

Incremental Personnel

Q. Does RECO have any human resource needs relating to the Company's ongoing initiatives, and/or its projected future capital project requirements and service reliability endeavors?

A. Yes. These are more fully described below. The incremental employees described below are engineering and operating personnel that direct charge their time to the applicable jurisdiction based on the actual work performed. Accordingly, the estimated percentage of the cost of these employees allocable to RECO is detailed in the direct testimony of Company witness Kosior.

<u>Underground Engineer for Distribution Engineering Dept.</u>

The Company's capital budget, and the associated number of projects, has been increasing in order to satisfy customers growing expectations on reduced number of outages and shorter restoration times during storm events. This trend is expected to continue, as presently identified by the Company's proposed incremental storm hardening and system resiliency studies. Based on the projected workload and a review of current engineering man-hours available, the Company has determined that additional resources will be required. This incremental engineering position will be responsible for the design, approval requirements, and construction oversight for various project installations on the distribution electric system with an emphasis on underground projects required for storm hardening. This engineer also will be required to prepare project specifications, obtain all field and environmental permits, and develop detailed project schedules/

budgets. Other responsibilities include construction supervision, operations support, and attendance at regulatory and industry meetings.

Q. What is the estimated annual cost for this position?

A. The Company estimates that the annual cost for this position will be $100,000, of which 30% will be O&M and 70% will be capital and charged to the specific projects being worked.

Q. How does the Company propose to recover the cost of this position?

A. The Company will be adding this position in the first quarter of 2014 and proposes to recover the cost of this position through the Company's base rate filing.

Q. Is the Company proposing to add any other positions?

A. Yes. While the following additional incremental personnel are not included as part of this base case, they will be required in the later years in order for the Company to complete its incremental Storm Hardening Program successfully.

<u>Chief Construction Inspector – Contract Management</u>

This incremental inspector position will be responsible for the field oversight of incremental storm hardening and system resiliency work performed by line contractors. Additional responsibilities include work requisitioning, work verification, payment reconciliation and invoice payment. The Company will add this position in 2015 and estimates that the annual cost for this position will be $115,000, all O&M. Additionally, in 2015 there would a one-time capital charge of $37,000 for a vehicle, computer and other equipment. The Company proposes to recover this cost through the proposed storm hardening surcharge.

Analyst – Contract Management

With the incremental increases in storm hardening and resiliency work performed by the Company's contractor group, there is an incremental increase in the amount of administrative work and analysis required. Field supervisory staff has been performing some of these added duties, taking time away from field oversight. To facilitate the productive and safe operation of the field workforce, the work needs to be re-tasked to this requested position. The Company will add this position in 2015 and estimates that the annual cost for this position will be $85,000, all O&M. Additionally, in 2015 there would a one-time capital charge of $4,000 for a computer and other equipment.. The Company proposes to recover this cost through the proposed storm hardening surcharge.

Line Operating Supervisor – Electric Operations

Based on the projected workload and a review of current operations man-hours available, the Company has determined that additional resources will be required. This incremental field supervisor position will be responsible for the construction oversight of various projects on the distribution electric system with an emphasis on incremental work required for storm hardening and system resiliency. This position will oversee the activities of the incremental work performed by Equipment Technicians requested for the enhanced distribution automation work. The Company will add this position in 2015 and estimates that the annual cost for this position will be $100,000, all O&M. Additionally, in 2015 there would a one-time capital charge of $37,000 for a vehicle, computer and other equipment.. The

Company proposes to recover this cost through the proposed storm hardening surcharge.

Chief Contract Inspector – Vegetation Management (five positions)

These five positions are required to maintain compliance with vegetation management regulations, implement vegetation management work in accordance with the Company's vegetation management plans and specifications, oversee and manage the contractor work force, and interact with stakeholders such as customers, landowners, community organizations, regulatory agencies, and elected officials. This work load performed by current staff has significantly increased in recent years due to regulatory requirements, improved vegetation management specifications, the associated needs for improved oversight of contractors, and more involved and improved communications required with stakeholders. The Company's present vegetation management program covers over 4,200 miles of overhead electric delivery infrastructure with the following: one manager, one planner, two company employed contract inspectors, three (contract) contract inspectors and one analyst. Field supervision in the group is regularly responsible for about 125 contractors (1:25 FTE ratio). The Company proposes to replace the contract inspectors with Company inspectors so as to provide stability and increased ownership by reducing turnover. In total, the Company proposes to add four inspectors to implement our expanded vegetation maintenance program and one to coordinate the expanded Hazard Tree Program (currently at a 1:18 FTE ratio). The Company will add these positions, one in each year from 2015 through 2019, and estimates that the annual cost for these positions to be $100,000 per position, all O&M. Additionally, each year there would a one-time capital charge of $37,000 for a vehicle, computer and other equipment. The Company proposes to recover this cost through the proposed storm hardening surcharge.

Q. Does this conclude your testimony?

A. Yes, it does.

Q. Would the members of the System Enhancement Panel (“Panel”) please state your names and business addresses.

A. (Glasser) Allisyn Glasser and my address is One Blue Hill Plaza, New York 10965.

(Prall) Stephen Prall and my address is 500 Route 208, Monroe, New York 10950.

Q. By whom are you employed, in what capacity, and what are your backgrounds and qualifications.

A. (Glasser) I am employed by Orange and Rockland Utilities, Inc. (“Orange and Rockland”), the parent company of Rockland Electric Company (“RECO” or the “Company”), as a Project Manager, in this role I am responsible for Outage Management System (“OMS”) and NRG Mapping Application Support and regulatory and business analysis support related to these systems as well as storm functions. I received a Bachelor of Science degree in Management Information Systems in 1994 from the University of Connecticut and a Masters of Business Administration degree in Project Management from DeVry University in 2007. I have worked for Consolidated Edison Company of New York, Inc. (“Con Edison”), Con Edison Communications (“CEC”) and Orange and Rockland since 1998 in various positions. I started with Con Edison as a Management Intern and have held positions as a Financial Business Analyst with CEC, Senior Financial Analyst in Treasury, Senior Planning Analyst in Shared Services, and Systems Manager in Information Resources prior to assuming my present position as Project Manager in Operations Systems Support.

(Prall) I am employed by Orange and Rockland as the Section Manager of the Transmission and Distribution Maintenance Section. In this role I am responsible for our Vegetation Management, distribution pole inspection, transmission operations and maintenance, and contract electric construction Programs. I received a Bachelor of Science degree in Nuclear Engineering in 1995 from the State University of New York and a Masters of Business Administration degree in 1998, from Renneslaer Polytechnic Institute, in Troy, New York. I have worked for Con Edison, and Orange and Rockland since 1989, as a Nuclear Chemist, Supervisor, Quality Assurance Engineer, Project Auditor, Manager of Training and Section Manager of Compliance, prior to assuming my present position as Section Manager of Transmission and Distribution Maintenance.

Q. Please briefly explain the purpose of the Panel's testimony in this proceeding.

A. The Panel will discuss various proposed enhancements to the Company's electric distribution system in order to maintain safe and reliable utility infrastructure, and particularly to mitigate the impacts of major storms, such as Hurricane Irene, the October 2011 snow storm and Superstorm Sandy (collectively, the "Major Storms"). The Panel would note that these proposed enhancements are outside the scope of, and incremental to, the expenditures normally incurred in the ordinary course of RECO's business of maintaining its utility infrastructure so as to provide, safe, adequate and reliable electric service to its customers in accordance with generally accepted industry norms.

ETR Tracking and Performance Tool

Q. Please describe the system and process enhancements RECO is implementing in order to improve estimated times of restoration ("ETRs")?

A. RECO is making various improvements in the accuracy of outage response planning and also enabling efficient and effective outage response performance tracking. The Panel would note that these improvements are consistent with the Board's recommendations (*e.g.*, Recommendation BPU-42) contained in the Hurricane Irene Order.[1] Improved outage response planning will enable RECO to better meet customers' needs by providing them with more accurate estimates of when their service will be restored. In addition, RECO has established a Priority Restoration Group ("PRG"). The PRG will be divided into teams, each of which will be equipped with Damage Assessors, Tree and Line Crews. The primary objective of the PRG is to remove downed power lines and create passable roads so as to restore normalcy to communities RECO serves. In addition, the PRG will work with the municipalities to identify and prioritize critical customers for restoration.

Effective tracking of outage response performance will enable RECO to adjust outage response plans more efficiently so as to improve communication and information with our operators, field crews, and customers as it relates to ETRs. Performance tracking will also enable RECO to more effectively identify and

[1] *I/M/O the Board's Review of the Utilities' Response to Hurricane Irene*, Docket No. ER11090543, Order Accepting Consultant's Report and Additional Staff Recommendations and Requiring Electric Utilities to Implement Recommendations (dated January 23, 2013)("Hurricane Irene Order").

rectify inefficiencies in its work plan development and restoration processes. By reviewing and tracking this data, the Company can review its ETR accuracy and make necessary changes in its processes to meet the ETRs provided. This will enable more granular correlation between outage response plans and specific outage incidents tracked by OMS.

Currently, RECO is analyzing historical outage event data in order to establish metrics and information to support and improve outage restoration planning activities. The Company will use such metrics and information to design and implement an internal outage restoration planning and performance tracking tool, including the software associated with such tool. This internal performance tracking tool will enable RECO to efficiently and effectively monitor restoration progress against the inputted plan and modify the plan according to the availability of updated information. It will allow proper tracking and monitoring of ETRs to verify that the Company is meeting the expected restoration times it is providing to its customers.

Q. Please describe the benefits of the ETR tracking and reporting tool.

A. The benefits include:

- Development of more realistic and more accurate storm restoration plans;
- Establishment of a centralized repository for ETR related information and tracking;
- Adoption of improved analytics to determine incident specific ETRs; and

- Availability of real-time performance tracking and more robust post-event analysis that will facilitate future improvements.

Q. What is the cost of implementing this ETR tracking and reporting tool?

A. The estimated capital cost of this software is $100,000. The Company is looking to have the ETR tracking reporting tool implemented by the 4th quarter of 2014.

Q. How does the Company propose to recover the cost of the ETR tracking and reporting tool?

A. The Company will provide updates in 2014 as part of this base rate case to recover these costs through reaching adjustments.

Damage Assessment Application

Q. Is the Company making improvements to its damage assessment capabilities?

A. Yes. RECO is making various improvements to its damage assessment application to assist in the calculation of individual level ETRs. The Panel would note that the implementation of these improvements is entirely consistent with the Hurricane Irene Order (*e.g.*, Recommendation BPU-41). The current application has been enhanced to streamline data entry processes, as well as support the use of technology in the field. The Company is currently in the second phase of this project and will be implementing a third-party vendor solution (*i.e.*, Sam Six). This application will provide the Company with advanced mapping and the ability to provide the damage accessor with step by step driving directions to the locations that need to be assessed, mobile applications for use by contractors, additional reporting. This application also will be used by both Orange and

Rockland and Con Edison which will assist in mutual aid support. The application will provide real time damage data. This data will then be used to generate estimated repair hours ("ERH") for various incidents. The ERH will be used as part of the process to establish the final individual level ETR for the customer as part of the work plan.

Q. Please describe the benefits of the damage assessment application.

A. The benefits include:

- Automation of manual damage assessment which typically is collected in hard-copy format;
- Receipt of "real-time" damage information from the field in a timely manner;
- Application is operable in a connected and unconnected state without loss of data;
- Prompt and direct association of damage with incidents reported in the OMS;
- Availability of photo and video recording of the actual damage;
- Availability of geocoding of the damaged location;
- Reduction of duplicative data entry;
- Availability of driving directions and prioritization of a circuit patrol; and
- Mobile application allows access for contractor use

Q. What is the cost of the Company making these improvements to its damage assessment capabilities?

A. The implementation of the system enhancements associated with these improvements will require a total capital investment of $325,000. The application development component of this project is $125,000 and $200,000 for tablet devices. These enhancements will be completed in the first quarter of 2014.

Q. How does the Company propose to recover the cost of the damage assessment application?

A. The cost of the tablet devices is reflected in the test year spending. With respect to the cost for the system enhancments, the Company will provide updates in 2014 as part of this base rate case to recover these costs either in the six-month projection or through reaching adjustments.

Staffing Requirements

Q. Please discuss the staffing requirements associated with the Company's system enhancement efforts.

A. Timely, efficient and effective storm preparation, restoration and response are one of the Company's top priorities. In reviewing the Company's preparation for and response to the Major Storms, as discussed above, the Company proposes to implement various system enhancement efforts. To support these efforts and to support the needs of our key stakeholders, the Company proposes to add a team comprised of the following four positions: one regulatory analyst and three process improvement business analysts.

The team will be assigned to address and support the implementation of the Company's system enhancements, as well as regulatory requirements and process initiatives. The team will be critical to the Company's efforts to interact with key internal and external stakeholders in a consistent and timely manner. These positions are more fully described below.

<u>Regulatory Analyst</u>

Since the Major Storms, the Board has implemented various new storm related requirements (see, for example, the Hurricane Irene Order). In this more demanding environment, it is critical that the Company address and effectively manage the requirements and expectations of our regulators and key stakeholders. RECO requires a regulatory analyst in order to manage and track regulatory initiatives and coordination. This new position will serve as a single point of contact for all regulatory related requests, orders and collaborations. This individual will assist in the overall planning and tracking of the deliverables and status, defining resources, providing direction and support to the responders, and improving efficiencies in how the Company coordinates and tracks data, as well providing consistent and accurate responses and information. In addition, this position will serve as a liaison between regulators, municipalities, customers and appropriate Company departments.

Q. What is the cost of the Company adding this regulatory analyst position?

A. The addition of this position will cost $90,000 annually and is included in the operation and maintenance ("O&M") portion of the revenue requirement in this proceeding.

<u>Process Improvement Business Analysts</u>

To support the Company's various systems and storm process related initiatives, the Company requires three additional business process improvement analysts. The work load to support these initiatives has increased significantly in recent years due to regulatory requirements, increased Company focus and awareness and improved processes and communications with stakeholders. These three analysts will be responsible for analyzing, documenting and implementation of storm related business processes to determine key process improvements, change management, training and communication. Based on the business requirements, these process improvements may result in new system implementation initiatives or existing process and system enhancements. This group will also facilitate business requirements, serve as the liaison between the business users and technical teams, and manage testing and user training.

Q. What is the cost of the Company adding these three process improvement business analysts?

A. Collectively, the addition of these three positions will cost $270,000 annually and is included in the O&M portion of the revenue requirement in this proceeding.

Q. Is RECO proposing to implement other systems or enhancements to maintain safe and reliable utility infrastructure?

A. Yes. RECO has identified the following systems and enhancements in the areas of vegetation and asset management, Automated Vehicle Location ("AVL"), and AMI installation.

Vegetation and Asset Management

The Company currently is developing damage assessment tools that utilize our current Geographic Information System ("GIS") vendor. The Company is seeking to leverage the damage assessment effort by incorporating current GIS data capabilities into its vegetation management (distribution system tree trimming), pole/structure management and other equipment and inspection programs. Over the latter half of 2012 and the first half of 2013, the Company met with six vendors and benchmarked with other utilities.

Staff has requested and the EDCs implemented components of A-3654 - Vegetation Management Legislation, specifically for the identification, tracking and resolution of danger trees. Currently, the Company's assignment of tree trimming projects is done manually, utilizing hardcopy, maps, times sheets, daily reports, and estimates. In addition, the Company performs a significant amount of tracking utilizing manually maintained electronic spreadsheets. The tracking of hazard trees, mitigation, vegetation related outage investigations will be data intensive and new tools will streamline and standardize the process and reporting. In addition, the Company's own program for the inspection and replacement of utilities poles and other assets is becoming increasingly data intensive. RECO's service territory contains 114 towers and 41,600 wood poles. The following are the identified areas for improved asset management practices within the Company's existing processes:

<u>Contract Construction</u> – The Company assigns overhead line construction projects manually, utilizing hardcopy, maps, times sheets, daily reports, and estimates. Also a significant amount of tracking is performed utilizing manually maintained electronic spreadsheets. This is data intensive and new tools will streamline and standardize the process and reporting.

<u>Asset Management</u> – The Company's inspection and maintenance of its towers and poles is performed manually, utilizing hardcopy, maps, times sheets, daily reports, and estimates. These inspections are conducted annually on the high voltage electric delivery system and every 10-12 years on the distribution system by a vendor. Currently, the inspection results are maintained in the vendor's database. Similar inspections performed by Company personnel are completed and maintained manually in electronic spreadsheets or manual updates to the vendor system. A capital project is under way to transfer this data into the Electric Inspection and Maintenance System ("EIMS"), which will (facilitate tracking and?)allow for comprehensive reports.

Q. Please continue.

A. Providing GIS enabled handheld computers would significantly improve asset management capabilities for the Company's vegetation management and line construction personnel. Specifically, the Company proposes to distribute 17 handheld computers for use to:

1. Identify planned vegetation work (high voltage ROW, distribution cycle, and hazard tree);

2. Identify and plan line construction;
3. Develop cost estimates based on contract units;
4. Provide work electronically to personnel;
5. Verify and document completion of work units;
6. Perform investigations of tree related outages;
7. Assign inspections and repairs of transmission assets to personnel; and
8. Perform and document inspections and repair of transmission assets.

In addition, improved asset management would provide database interfaces with current and to be developed data management tools. These would include:

1. Tracking and reporting of completed vegetation work;
2. Tracking and reporting of unmitigated hazard trees;
3. Work estimates for the requisition of work;
4. Potential link to Oracle EBS I procurement system;
5. Tracking and reporting of completed work;
6. Tracking and reporting of tree related outages; and
7. Tracking and reporting on Transmission Asset Condition.

Q. What is the cost of the Company adding these GIS enabled handheld computers and associated programs?

A. Adding these GIS enabled handheld computers and associated programs is estimated to cost $729,000, which includes (i) configuration and integration of the Vegetation Management and Asset Management modules at $550,000, (ii) the purchase of 13 Trimble GeoExplorer 6000 series, $13,000 each totaling $169,000 and (iii) 4 - Panasonic Toughpads, $2,500 each totaling $10,000.

Q. How does the Company propose to recover the cost of these GIS enabled handheld computers and associated programs?

A. The Company will provide updates in 2014 as part of this base rate case to recover these costs through reaching adjustments.

Automated Vehicle Location

Q. Please discuss the Company's proposed AVL upgrade.

A. The Company currently has AVL implemented in various trucks for tracking purposes. An upgrade is necessary to access faster network speeds and technology. The newer and faster network speed will improve both operational performance for field workers and increase data transfer on the Company's network. The increased bandwidth will allow for faster application performance as well as improved radio communications, which will be particularly beneficial during storms. The vehicle GPS capability provides the locations of our field operations fleet and allows the Company's Control Center to identify the nearest crew in case of an emergency situation. It also provides a safety mechanism to locate a vehicle in an emergency situation.

Q. What is the cost of the proposed AVL upgrade?

A. To upgrade the Company's current infrastructure will require a capital investment of approximately $164,000. There is no associated O&M cost.

Q. How does the Company propose to recover the cost of the proposed AVL upgrade?

A. The Company proposes to recover this cost through the Company's proposed storm hardening surcharge.

Advanced Metering Infrastructure Installation

Q. Please discuss the Company's proposal to install AMI in its service territory.

A. As discussed in the direct testimony of Company witness Burke, commencing in 2015 RECO is proposing to install AMI throughout the Bergen County section of RECO's service territory. The implementation and integration of an AMI application to the Company's OMS will enhance the Company's storm restoration and response capabilities. The interface between AMI and OMS will facilitate the integration of outage data from the AMI application. OMS will process this data and incorporate it into its predictive logic business rules to predict the root cause of outages. This data will then be grouped into parent/ child relationships to facilitate work plan development. A parent incident will need to be completed prior to a child incident to restore customers. This user friendly view allows the dispatcher to identify these types of incidents. In addition to receiving outage data, OMS will be able to use the same interface to receive outage data on meters that are pinged within the AMI application. This data will be used to identify nested outages during the restoration process. The availability of this data will allow the Company to identify areas that still require restoration and confirm when all outages have been restored. The cost estimate for both integration points is set forth in EXHIBIT _ (JLB - 1).

Q. How does the Company propose to recover the cost of this AMI integration?

A. The Company proposes to recover this cost through the Company's proposed storm hardening surcharge.

Q. Does this conclude your testimony?

A. Yes, it does.