STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

Rockland Electric Company
Docket No. _________________

Direct Testimony

Volume I

ROCKLAND ELECTRIC COMPANY

TESTIMONY

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ROCKLAND ELECTRIC COMPANY
DIRECT TESTIMONY OF
ACCOUNTING PANEL

NJBPU Docket No. _____________

Q. Would each member of the Accounting Panel ("Panel") please state his name and business address.

A. John de la Bastide, One Blue Hill Plaza, Pearl River, New York 10965.
Kyle Ryan, 4 Irving Place, New York, NY 10003.
Wenqi Wang, 4 Irving Place, New York, NY 10003.

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

A. (de la Bastide) 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 – Financial Services.

(Ryan) I am employed by Consolidated Edison Company of New York, Inc. ("Con Edison" or "CECONY"), a utility affiliate of O&R and RECO, where I hold the position of Department Manager of Regulatory Filings.

(Wang) I am employed by CECONY, where I hold the position of Department Manager of Regulatory Accounting and Revenue Requirements.

Q. Please briefly outline your educational and business experience.

A. (de la Bastide) I graduated from Hofstra University in 1985 with a Bachelor of Business Administration in Accounting. I was employed by Con Edison for 30 years. Between 1986 and 1996, I was promoted to various supervisory positions in Corporate Accounting. In 1998, I was promoted to the position of Section Manager, Employee Benefits. In 2001, I was promoted to Department Manager, Financial Forecasting, in Corporate Accounting and have held various positions as Department Manager in Corporate Accounting and Electric Operations. I became Department Manager, Benefits and

Compensation, in March 2007. In June 2011, I was promoted to Director of Compensation. In November 2016, I became an employee of Orange and Rockland and assumed the role of Director of Financial Services. I have submitted testimony before the New Jersey Board of Public Utilities ("Board" or "BPU") and the New York Public Service Commission ("NYPSC").

(Ryan) I graduated from the University of Wisconsin-Madison in 2006 after earning a Bachelor of Business Administration in Accounting and a Masters of Accountancy. I began my employment with Con Edison in 2012 as a Senior Accountant in the Accounting Research and Procedures section and was promoted to Department Manager of the section in 2014. I assumed my current position as Department Manager of Regulatory Filings in June 2017. Prior to joining Con Edison, I worked for Ernst & Young in Minneapolis, Minnesota from 2006 to 2012, ultimately reaching the position of Audit Manager. I am a licensed CPA in New York and Minnesota.

(Wang) In June 1999, I received a Bachelor of Science Degree in Accounting from the University at Albany, State University of New York. I began my employment with Con Edison in July 1999 as a Management Intern. I worked in the Corporate Accounting Department from July 2000 until April 2014 primarily in the General Accounts section starting as a Staff Accountant, then as Supervisor and ultimately reaching the Department Manager level. In May 2014, I assumed my current position as Department Manager of Regulatory Accounting and Revenue Requirements.

Q. Have you previously submitted testimony before the Board?

A. (de la Bastide) Yes, I submitted testimony on behalf of the Company as part of the Accounting and Rate Panel in RECO's Storm Hardening Proceeding, BPU Docket No. ER14030250, RECO's Storm Hardening Base Rate Adjustment

Proceeding, BPU Docket No. ER18101114, and RECO's Low Income Audit and RECO's Low Income Audit and Direct Install Energy Efficiency III Program, BPU Docket No. ER17080869.

(Ryan) No.

(Wang) I submitted testimony in RECO's last base rate proceeding, BPU Docket No. ER16050428.

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

A. Our direct testimony first provides background information on RECO and an overview of the Company's base rate case filing. We then address the following exhibits, all of which were prepared under the Panel's supervision and direction:

P-1 Historical Financial Statements;

P-2 Electric Cost of Service; and

P-3 Electric Rate Base.

We also discuss the storm hardening related upgrade projects that we propose for finalization of base rate recovery in this proceeding. Finally, we will discuss one modification to the current provisions governing the Company's deferral of major storm costs and RECO's proposal for "No-Fee" Debit/Credit Card Transactions.

Q. Are you familiar with RECO's books and records, including the Board-approved Joint Operating Agreement ("JOA") between O&R and RECO?

A. Yes. We are familiar with RECO's books and records, including the JOA, which has been approved by the Board. Pursuant to the JOA, certain costs, including but not limited to salary and payroll taxes, are allocated from O&R to RECO.

BACKGROUND

Q. Please describe RECO and its relationship with Orange and Rockland.

A. RECO, a New Jersey corporation, is engaged in the delivery of electricity for residential, commercial and industrial purposes within parts of Bergen, Passaic and Sussex Counties in New Jersey. RECO is a wholly-owned utility subsidiary of Orange and Rockland, a New York corporation. RECO and Orange and Rockland jointly operate a single fully-integrated electric system ("System") serving parts of New Jersey and New York to the extent discussed below. Neither RECO nor Orange and Rockland own any generating assets. A Power Supply Agreement ("PSA") between Orange and Rockland and RECO reflects and provides for the integrated operation of the System and for the allocation of System purchased power related costs between them according to their pro rata use of the System. The PSA is a Federal Energy Regulatory Commission ("FERC") approved tariff and is regulated by the FERC pursuant to its jurisdiction under Sections 205 and 206 of the Federal Power Act. The PSA provides for detailed cost allocation procedures for power supply costs. Most power supply costs are allocated by use of energy ratios. In contrast, transmission and distribution costs are allocated by use of a demand ratio.

The JOA between Orange and Rockland and RECO provides the basis for billing RECO for jointly used property, customer accounting, customer service, and administrative and general services provided by Orange and Rockland. The JOA provides that costs that can practically be directly assigned are directly assigned. Administrative costs and general costs that cannot be directly charged are allocated by use of a revenue ratio. Customer costs that cannot be directly charged are distributed based on the relationship of the number of customers. As noted previously, the Board has approved the JOA.

Q. Is RECO associated with the New York Independent System Operator ("NYISO") and the PJM Interconnection LLC ("PJM")?

A. Yes. RECO is associated with both entities. O&R, on behalf of the System (of which RECO is a part), is a member of the NYISO. Retail competition for the System is tied directly to the operations of the NYISO. The NYISO, which commenced operations in November 1999, administers markets for the purchase and sale of energy, capacity and ancillary services. Prior to March 1, 2002 competitive electric sales in RECO's entire service territory were implemented through the NYISO. However, effective March 1, 2002, after receiving FERC approval, RECO transferred its Eastern Division in Bergen County, representing more than 90 percent of RECO's customers/load, from the control area of the NYISO to that of the PJM. This transfer facilitated RECO's participation in the Basic Generation Service ("BGS") auction process approved and overseen by the Board. That BGS auction process has resulted in a Board-approved competitively procured BGS supply for RECO's customers. RECO has participated in all BGS auctions since the time it became part of the PJM. RECO's Central and Western Divisions located in Passaic and Sussex counties remain associated with the NYISO.

<u>OVERVIEW OF RECO'S FILING</u>

Q. Why is RECO filing this base rate case?

A. Rate relief is necessary to provide RECO with cost recovery for increased expenses and the investment in the Company's infrastructure necessary to maintain reliable, safe and secure electric service including by providing a fair and reasonable return on the Company's investment. The Company seeks rate relief to recover significant increases in costs relating to ongoing infrastructure improvements, the cost of capital, recovery of storm costs, plant removal costs and changes in depreciation rates, operation and maintenance ("O&M") expenses, and employee wages and benefits.

Q. When was RECO's last base rate case?

A. RECO submitted its last base rate case filing to the Board on May 13, 2016. In its Order Approving Stipulation dated February 6, 2017 in BPU Docket No. ER16050428 ("February 2017 Rate Order"), the Board approved the terms of a Stipulation of Settlement ("Settlement") that provided for a rate increase of $1.7 million, equivalent to a 0.7% increase in overall revenues, effective March 1, 2017. The Settlement was executed by the parties on February 6, 2017 and provided for a return on equity of 9.60% with an overall rate of return of 7.47%. The revenue requirement calculation was based on a January 2016 through December 2016 test year, reflecting a distribution rate base of $178.7 million.

Q. Has the Board implemented any changes to RECO's base rates since the February 2017 Rate Order?

A. Yes.

Q. Please discuss.

A. The Board has approved the following five changes to the Company's rates, all of which occurred after the February 2017 Rate Order and prior to the end of the 12-month test year period in this proceeding ending September 30, 2019 ("Test Year"):

- The first rate change related to a Storm Hardening Program rate adjustment Petition the Company filed on October 16, 2017 ("October 2017 Petition"). On March 26, 2018, the Board issued its Order in BPU Docket No. ER17101066, approving an increase to base rates of $483,382 in order to allow the

Company to recover carrying charges associated with $4,049,584 of storm hardening plant additions.

- The second rate change resulted from the Board's Decision and Order dated June 22, 2018 in BPU Docket No. ER18030236 ("TCJA Order"). This Order reflected in the Company's rates the impact of the December 22, 2017 Federal Tax Cuts and Job Act ("TCJA"). Applying the changes enacted by the TCJA to RECO's annual federal income tax expense, the Board authorized a one-time refund of approximately $1.019 million to the Company's customers during July 2018, relating to the Stub Period (*i.e.*, January 1 through March 31, 2018) over-collection. The Board also implemented a reduction in the Company's annual revenue requirement of $2.868 million resulting from the TCJA's decrease in the statutory federal income tax rate from 35% to 21%, effective April 1, 2018. Finally, the Board authorized the Company to refund to its customers the unprotected accumulated deferred income taxes of approximately $10.6 million (grossed up amount), inclusive of SUT, over a three-year period, commencing in July 1, 2018. Excluding the one-time refund of $1.019 million made during July 2018, the annual reduction to base rates through June 2020 relating to the TCJA will be $6.4 million (*i.e.*, $2.868 million plus $3.553 million [$10.6 million / 3 years]).
- The third rate change that became effective on August 1, 2018, reduced the Company's base rates by $6,413,091 in order to eliminate the four-year recovery of deferred extraordinary storm damage costs of approximately $25,652,364 pursuant to the Board's Order Approving Stipulation dated July 23, 2014 in *I/M/O the Verified Petition of Rockland Electric Company for Approval of Changes in Electric Rates, et al., (*BPU Docket No. ER13111135).

Under the terms of this Order, RECO's base rates were reduced effective August 1, 2018, in order to reflect the completion of the amortization.

- The fourth rate change allowed the Company to recover additional Storm Hardening expenditures requested by the Company in its October 15, 2018 Petition ("October 2018 Petition"). By Order dated March 13, 2019, in BPU Docket No. ER18101114, the Board approved an increase to base rates of $416,647 effective April 1, 2019, in order to allow the Company to recover carrying charges on $4,577,517 of storm hardening plant additions.
- The fifth rate change will be the elimination of the Transitional Bond Charge ("TBC") in June 2019, which will have the effect of reducing customer bills by an additional $3.7 million annually.

Q. What was the overall net change to rates as a result of the rate changes discussed above?

A. As a result of those rate changes, the Company's rates will be reduced by approximately $15.6 million since the implementation of rates approved in the February 2017 Rate Order. This is the equivalent of approximately a 9.2% decrease of overall revenues as detailed below:

2018 Storm Hardening Adjustment	$0.5 million increase
Tax Cuts and Job Act	$(6.4) million decrease
Elimination of Storm Cost Recoveries	$(6.4) million decrease
2019 Storm Hardening Adjustment	$0.4 million increase
Elimination of TBC	$(3.7) million decrease
Total	$(15.6) million decrease

Q. Should the Board take into account the net rate reductions of approximately $15.6 million in analyzing the Company's proposed rate request?

A. Yes. The Board should evaluate the Company's proposal to increase the

Company's electric distribution rates, as set forth in this Petition, in light of the net reductions to the Company's electric distribution rates resulting from the TCJA, completed storm cost recoveries, elimination of the TBC, and storm hardening updates.

A fairly significant portion of the Company's current filing is to recover deferred storm costs incurred through the end of the Test Year. Absent any new storm costs between now and September 30, 2019, the Company will have approximately $13.3 million of deferred storm costs. The total impact of recovering the deferred storm costs over three years, combined with the additional annual funding of $750,000 the Company is seeking to fund the current Storm Reserve (along with carrying costs on the deferred balance), represents approximately $6.1 million ($13.3 million / three years plus $750,000, plus $1.0 million of carrying cost on $13.3 million of deferred expenditures) of the rate increase the Company is requesting in this case.

Had the prior annual storm cost recoveries of $6.4 million continued (instead of being eliminated August 1, 2018) and been reflected on the Company's books for the benefit of customers, those amounts could have been used in part, to avoid the impact of first lowering and then increasing customer rates to recover new deferred storm costs.

In addition, had the net decrease for savings realized by the TCJA been deferred instead of being passed back to customers immediately, such decrease also could have been reflected as a partial offset to mitigate the rate increase the Company is seeking in this proceeding.

Q. Are the Company's current electric distribution base rates just and reasonable?

A. No, the Company's electric distribution base rates are no longer just and reasonable. Rather, they are inadequate and need to be increased. For the Test Year, the Company is projecting to earn an overall rate of return of 1.87% in its distribution cost of service (*see* Exhibit P-2, Summary, Page 2 of 4). This would be equivalent to a negative return on equity of 1.4%. With the inclusion of the reasonable adjustments to revenues and expenses demonstrated in the Company's filing, the Company projects an overall return of 7.56% (*see* Exhibit P-2, Summary, Page 2 of 4). This would be equivalent to an earned return on equity of 10.0%.

Q. Why do RECO's base rates need to be increased now?

A. As noted above, RECO's existing base rates are inadequate. RECO's base rate filing demonstrates the need for an increase in base distribution rates to provide the revenues necessary to recover RECO's increased cost of providing service and a fair return on investment. There are several factors driving this need including: lower sales (*e.g.*, resulting from increased customer conservation); expenditures for infrastructure construction; storm cost recoveries; and increases in depreciation on new plant and removal costs as plant assets reach the end of their useful lives. In addition, inflationary pressures that have increased operating costs over the past several years for labor and materials and increased expenditures on vegetation management contribute to the request. As described in the direct testimony of (1) the Company's Capital Budgets and Plant Addition Panel and (2) Mr. Scerbo (describing the implementation of the Company's Advanced Metering Infrastructure ("AMI") program), the Company is undertaking various infrastructure improvements necessary to maintain the level of reliable service that RECO's customers have come to expect. The construction program will improve the reliability and security of the Company's energy distribution system for current customers while providing the additional benefit of allowing for future load growth in certain areas. The Company's implementation of the AMI program will provide for proactive customer energy management, improved system efficiency and reduced duration of outages. RECO is relying on the Board to enable the funding of its construction program, which is vital to meeting its customers' reliability expectations, and to strengthening the security of its system. Providing a reliable and secure energy distribution system is also critical to the continued economic development in RECO's service territory. The Accounting Panel will discuss increases in salary and wages and changes in associated benefit costs. The Depreciation Panel outlines changes to the Company's current book depreciation rates, allowance for removal cost (*i.e.*, negative net salvage costs), and recovery of retired meter costs which if adopted would result in higher annual depreciation expense and related allowances.

Q. What changes to distribution rates is RECO proposing?

A. Based on the Test Year cost of service, rate base and cost of capital, RECO requires a $19.9 million increase in distribution rates, which represents a 13.6% increase in total distribution revenues in order to achieve an overall rate of return of 7.56%. Taking into account the net rate decreases discussed above of approximately $15.6 million, which was equivalent to 9.2% of total revenues reflected in the 2017 Rate Order, the overall net increase to customers since the last base rate case would be approximately $4.3 million ($19.9 million less $15.6 million) or 2.5%.

Q. What is the customer impact of the proposed distribution rate adjustment?

A. As noted in the direct testimony of the Company Electric Rate Panel, the percentage increase on total revenues is 9.6% when total revenues include an estimate of electric supply costs for retail access customers. Taking into account the impact of the aforementioned net rate decreases of approximately $15.6 million, the percentage increase on total revenues is 2.1%. This number is more indicative of the overall impact of the revenue increase on RECO's customers.

Q. Does this RECO filing represent a distribution-only case?

A. Yes, RECO has filed an electric distribution base rate case. The genesis of this approach was RECO’s separate statement of its transmission and distribution rates pursuant to the Board’s October 3, 2002 Decision and Order in BPU Docket No. ET02030167, effective November 1, 2002. The Company’s filing in the current base rate case is consistent with and continues that distribution-only approach.

Q. How did you eliminate the transmission components of the revenue requirement?

A. The Company followed the standard FERC transmission rate formula for assigning revenues, expenses and rate base to transmission. All direct transmission revenues, expenses and rate base items were excluded from the distribution revenue requirement calculation. Power supply billings between O&R and RECO were broken down into its purchased power, transmission and distribution components. The transmission component was excluded from the distribution revenue requirement. Administrative expenses, general plant and its associated depreciation expense were allocated to transmission based on the ratio that transmission bears to distribution O&M and plant balances respectively. Taxes including property, ancillary and income were assigned directly or allocated using the factors above. The stipulated revenue requirements approved by the Board in the February 2017 Rate Order were determined by this method.

Q. Has the Company accounted for any transmission components differently in this base rate filing than in its last base rate filing?

A. No. The Company has not made any changes in its accounting procedures for any of the transmission components.

HISTORIC FINANCIAL STATEMENTS

Q. Was Exhibit P-1 prepared by you or under your direct supervision?

A. Yes.

Q. Please describe its contents.

A. Exhibit P-1 contains the financial data for RECO required by Board regulations. Schedule 1 is entitled "Rockland Electric Company – Comparative Balance Sheets." It shows the balance sheets of the Company at December 31 for the years ended 2016, 2017, 2018, and March 31, 2019 for comparative purposes. The figures shown on these schedules have been taken from RECO's books.

Q. Please describe Schedules 2 and 3.

A. Schedule 2 is entitled "Rockland Electric Company – Comparative Statement of Income" for the years ended December 31, 2016, 2017, 2018, and March 31, 2019. Schedule 3 is a Statement of Retained Earnings for the years ended December 31, 2016, 2017, 2018, and March 31, 2019. These schedules show income, expenses and retained earnings for those years, as taken from RECO's books, for comparative purposes.

Q. Please describe Schedule 4.

A. Schedule 4 is entitled “Intercompany Account – Payable to Orange and Rockland Utilities, Inc. (Year 2018).” It shows that the cost of RECO’s share of the system Power Supply Expense for the same period was approximately $19.5 million. The Company determined these charges in accordance with the terms of the PSA between RECO and Orange and Rockland (FERC Schedule No. 61).

Q. Please describe Schedule 5.

A. Schedule 5 supports the charges billed by O&R to RECO in accordance with the terms of the JOA. The cost of services provided by O&R to RECO and the carrying charges for jointly used property billed pursuant to the terms of the JOA amounted to approximately $94.8 million for the year 2018. The schedule sets forth by account each item for which either a direct charge or a cost allocation is made.

Q. What type of services does O&R bill to RECO based on direct charges?

A. Pursuant to the JOA, billings are made on a direct charge basis for services rendered to RECO by O&R whenever it is practicable based on payroll records, direct payments to vendors, and usage studies supporting the distribution of clearing accounts. The direct charge billings are for activities and services rendered for the benefit of RECO’s customers, such as the operation and maintenance of distribution facilities, construction or purchase of utility plant, and collection of customer billings and other services required for operations.

Q. Please describe the type of costs allocated to RECO by O&R and the methods of allocation.

A. The type of costs allocated and the basis for such allocations are defined in Article 2 of the JOA. Customer related costs that are impractical to charge on a direct basis, such as customer accounting and customer service, are allocated by use of the following customer ratios based on the relationship of the preceding calendar year number of customers of RECO, and the total number of customers of O&R and RECO. For 2019 (based on calendar year 2018 data), the ratios are as follows:

A0 Ratio = RECO Customers / Total O&R and RECO Customers

73,720 / 444,150 = 16.60%

The A0 Ratio is used to allocate costs that are common to both the electric and gas operations of O&R and the electric operations of RECO.

E0 Ratio = RECO Customers / Total O&R and RECO Electric Customers

73,720 / 307,266 = 23.99%

The E0 Ratio is used to allocate costs that are common to the electric operations of O&R and RECO.

Administrative and general expenses that are impractical to charge on a direct basis are allocated by use of ratios based on the relationship of the preceding calendar year net revenues of RECO and O&R. Net revenues exclude energy cost recoveries and revenue taxes for each company. For 2019 (based on calendar year 2018 data), the ratios are (all amounts are in thousands of dollars) as follows:

A0 Ratio = RECO Revenue / Total O&R and RECO Revenue

$113,696 / $659,814 = 17.23%

The A0 Ratio is used to distribute costs that are common to both the electric and gas operations of O&R and the electric operations of RECO.

E0 Ratio = RECO Net Revenue / O&R and RECO Electric Net Revenue

$113,696 / $462,388 = 24.59%

The E0 Ratio is used to distribute costs that are common to the electric operations of O&R and RECO.

RECO owns its proportionate share of the general materials and supplies inventory. The allocation of the general materials and supplies inventory is determined as follows:

(1) General electric stock items are allocated on the ratio of the number of RECO customers to the total number of electric customers of O&R and RECO at the end of the preceding calendar year. For 2019, the electric customer ratio was 23.99%.

(2) Common stock items usable in both electric and gas operations such as gasoline, small tools, and storeroom expenses are allocated on the ratio of the number of RECO customers to the total number of electric and gas customers of O&R and its subsidiaries at the end of the preceding calendar year. For 2019, the total customer ratio was 16.60%.

The consolidated Federal income tax liability is allocated among O&R and its subsidiaries as provided for in Section 1552-1(a) (2) of the Internal Revenue Code of 1954. The liability is computed on the basis of separate returns as though the companies had always filed separate returns with the tax liability allocated to the subsidiaries never exceeding their separate return liability

<u>RATE BASE</u>

Q. Please describe the rate base Summary schedule contained in Exhibit P-3.

A. The Summary schedule shows the total electric rate base for the Test Year. The rate base is then reduced by transmission related items resulting in a rate base representative of the distribution portion of the business. The rate base includes net plant consisting of plant in service, plant held for future use, non-interest bearings construction work in progress, and depreciation reserves. It also includes working capital requirements, net deferred costs relating to storms, management audit assessments, rate case expenditures, protected federal income tax credits, and other remaining regulatory balances from amortizations approved in BPU Docket No. ER16050428, customer deposits, customer advances for construction, accumulated deferred income taxes, and a consolidated tax adjustment related to non-utility affiliates. Each schedule supporting the various items of rate base shows the allocation between transmission and distribution. This exhibit will be updated as actual results become available.

Q. Please describe Schedule 1.

A. Schedule 1 shows the derivation of gross plant, both transmission and distribution, for the Test Year. We started with the actual balances of plant in service as of March 31, 2019. We then added the budgeted plant additions and subtracted the retirements for the six months ending September 30, 2019 to calculate the projected plant in service balance as of September 30, 2019. In addition, we have reflected several post-Test Year capital additions and retirements. These post-Test Year adjustments are addressed in the direct testimony of the Capital Budget and Plant Addition Panel.

Q, Please describe the major plant additions included in this filing.

A. As described in the direct testimony of the Capital Budget and Plant Addition Panel, as well as Mr. Scerbo's testimony, by the end of the Test Year the Company will have added approximately $10 million in new plant as shown on Exhibit P-3, Schedule 1 (*i.e.,* April through September 2019 additions of $9.991 million). As noted above, these additions will help maintain the level of safe and reliable service that our customers have come to expect. The construction program will improve the reliability and security of the Company's energy distribution system for current customers while allowing for future load growth in certain areas. The Company's implementation of the AMI program will provide for proactive customer energy management, improved system efficiency and reduced duration of outages. As noted in the Capital Budget and Plant Addition Panel testimony, some of the major plant additions include the Closter Breaker Replacements and rebuilding the underground distribution facilities in the Bald Eagle Park subdivision in Ringwood covering Sweatwater Lane, Fieldstone Drive, Old Forge Road, and Copper Hill Park. In addition, the plant additions include RECO's Electric Distribution, Meter and Transformer Blankets as well as the Smart Grid Automation and Resiliency Program. In addition, as discussed in the AMI testimony, the Company expects to complete the entire New Jersey service territory mass deployment of AMI meters (*i.e.*, approximately 73,000 meters) by the end of the second quarter of 2019.

Q. Why are post-Test Year additions included in rate base?

A. As discussed in the Capital Budget and Plant Addition Panel's direct testimony, as well as Mr. Scerbo's direct testimony, RECO is undertaking several major infrastructure improvement projects that will conclude following the Test Year but meet the Board's requirements for post-test year capital additions. These projects are either underway or will commence during or shortly after the Test Year. As the Capital Budget and Plant Addition Panel testifies, these projects are critical to maintaining the reliable, safe, and secure energy supply required by the Company's customers.

Q. Why should the Board approve the inclusion of these post-Test Year additions to rate base?

A. The Capital Budget and Plant Addition Panel's testimony demonstrates that the capital additions are known and measurable changes appropriate for inclusion in rate base. If the Board suspends for eight months the rates that the Company has proposed to be effective June 2, 2019, then rates will not become effective until approximately February 3, 2020. The additions to rate base will occur within six months of the conclusion of the Test Year and be in place in the beginning of the period that new distribution rates are effective. The Capital Budget and Plant Addition Panel demonstrates that the investments are prudent and the amounts are significant for RECO, and has quantified and supported those amounts through their testimony. Several of these projects include the Allendale Breaker, Replacement, Old Tappan – Howard Drive, Oakland – Long Hill Road Conversion, Allendale 39-1 and 39-6 Reroute, and Blanche Road Underground Circuit. In addition, the Capital Budget and Plant Addition Panel discusses the need for approximately $10 million in additions by September 2019, *i.e.*, within the Test Year.

Q. Please describe Schedule 2.

A. Schedule 2 shows the balance of $209,000 in electric plant held for future use as of March 31, 2019. This balance represents the cost of land and an easement for a new distribution substation in Wyckoff and is not projected to change during the Test Year.

Q. Please describe Schedule 3.

A. Schedule 3 includes the derivation of the twelve-month average of total electric non-interest bearing construction work in progress for the twelve months ending September 30, 2019. This amount was allocated 91.68% to distribution.

Q. Please describe Schedule 4.

A. Schedule 4 shows the derivation of the accumulated depreciation reserve for Electric Plant in Service as of September 30, 2019. We started with the actual depreciation reserve balances as of March 31, 2019 and then added the budgeted depreciation accruals based on the currently effective depreciation rates and subtracted retirements of properties and the estimated net removal costs associated with those retirements. In addition, we have reflected additional depreciation related to post-Test Year capital additions and retirements mentioned earlier.

Q. Please describe Schedule 5.

A. Schedule 5 shows the actual accumulated depreciation reserve as of March 31, 2019 for Electric Plant Held for Future Use. Because the Company's Electric Plant Held for Future Use balance is comprised solely of land and an easement for the Wyckoff distribution substation, there is no accumulated depreciation related to those assets nor are there any projected changes in depreciation reserve through September 30, 2019.

Q. Please describe Schedule 6.

A. Schedule 6 details average working capital requirements for the Test Year. We divided the total working capital requirements into three parts:

- Net Cash Working Capital;
- Prepayments; and
- Materials and Supplies.

The last two components were calculated by determining the average monthly balances outstanding during the Test Year and 91.68% was allocated to RECO's distribution operations where applicable. A lead-lag study was performed to determine the first component, cash working capital, as discussed later in our testimony.

Q. Please describe Schedule 7.

A. Schedule 7 shows the deferred balances for management audit assessments, rate case expenditures, protected federal income tax credits, and for other net regulatory deferred assets and liabilities that the Company is authorized to amortize over varying periods pursuant to the Board's February 2017 Rate Order.

Q. Please describe Schedule 8.

A. Schedule 8 shows the net storm reserve under-recovery. Starting with the actual storm reserve balance as of March 31, 2019, the schedule adds the current rate allowance for the period April – September 2019 in order to estimate the net deferred balance as of September 30, 2019. The Panel did not project any storm charges in the April – September 2019 time period.

Q. Please describe Schedule 9.

A. Schedule 9 reflects the net pension and other post-employment benefits ("OPEBs") liability accrued on the Company's books as of September 30, 2019. Both the actual net pension and OPEBs liability at March 31, 2019 and the projected net pension and OPEBs liability at September 30, 2019 are $0.

Q. Please describe Schedule 10.

A. Schedule 10 shows the average balance of Customer Advances for Construction and Customer Deposits that the Company developed by using rolling twelve-month averages for the twelve months ending September 30, 2019.

Q. Please describe Schedule 11.

A. Schedule 11 shows the various deferred taxes related to plant. The Panel started with the actual balances as of March 31, 2019 and then reflected the tax effects of various plant additions and amortizations, including post-Test Year adjustments.

Q. What does Schedule 12 show?

A. Schedule 12 shows the anticipated major plant additions for the period covering April 2019 through March 2020 by calendar quarter. The Capital Budget and Plant Addition Panel provided these amounts and discusses these projects in their direct testimony.

Q. Please describe Schedule 13.

A. Schedule 13 contains the consolidated tax adjustment calculated in accordance with the methodology set forth in the Board's regulations (N.J.A.C. 14:1-5.12(a)11). The adjustment will be updated during the course of the proceeding to reflect the latest known actual data for the last five calendar years (*i.e.*, 2014, 2015, 2016, 2017, and 2018). For purpose of this filing the Panel used calendar year 2017 as a proxy for amounts to be experienced in 2018). The 2018 data will be finalized when the Company files its 2018 consolidated tax return in September 2019 and will be reflected in the Company's 12+0 Update. The total pro forma consolidated tax adjustment amounts to $0.025 million, of which 91.73% or $0.023 million, is allocable to distribution operations.

<u>CASH WORKING CAPITAL</u>

Q. Please provide an overview of your lead/lag study and describe its results.

A. The purpose of the cash working capital component of rate base is to compensate the Company for funds it provides to pay operating expenses in advance of receipt of revenue. It reflects the amount of capital over and above investment in plant and other separately identified rate base items provided by the Company to bridge the gap between the time expenditures are required to provide service and the time collections are received for that service. A lead or lag reflects the amount of time that elapses between when a party provides a product or service, and when that providing party is compensated for the product or service provided. For the purpose of this study, the Company calculated the amount of lead or lag times in days. We calculated the lag days and applied them to the cost of service inputs for the Test Year in order to determine the cash working capital requirement of RECO that is reflected in rate base. The study indicates a cash working capital requirement of $6,504,345 as shown on Exhibit P-3, Schedule 6, Page 2.

Q. Please describe the revenue component of the lead/lag study.

A. The lag on revenue collection consists of three components:

- The time between rendering of service and meter reading;
- The time between meter reading and billing of services; and
- The time between billing of services and collection of revenue.

RECO's customers are billed on a monthly cycle. The average time from the rendering of service to meter reading date is calculated to be 15.2 days. The 15.2 days was calculated by dividing 365 days by twelve months and then dividing by two to achieve the mid-point for each monthly service period (365 / 12 = 30.4 / 2 = 15.2). Based on an examination of the meter reading and billing data for the year ended December 31, 2018, on average, it took 1.5 days from the time meters were read to the time bills were generated and mailed out. Generally, billing occurs the same day the meter reading is completed for that particular cycle, with mailing occurring the following day. The billing to collection lag was determined by analyzing payments during 2018. Average lag days were generated for each revenue class of billing and weighted by their amounts. Based on this analysis, on average, bills were outstanding for 23.7 days. Combined, the total lag in revenue recovery of energy bills and miscellaneous operating revenues is 40.4 days.

Q. Please describe the treatment of cost of service in the study.

A. The cost of service was broken down into the basic components of operating expense and operating income. Operating income, which represents a return on invested capital, is included as a component of the cost of service.

Q. Please describe the treatment of purchased power expenses in the study.

A. The cost of purchased power and related expenses allocated to RECO by O&R in accordance with the terms of the PSA, as well as the BGS supply costs resulting from the BGS auction, are the basis for the lead/lag on purchased power costs. Under the PSA, there is a 45-day lag based on the payment terms included in the agreement. The PSA states that payments are due 30 days after the month in which services were rendered. The lag is measured from the mid-point of the month (30 days / 2 = 15) to the date of payment for services (30 days), totaling 45 days. For purchases made pursuant to the BGS auction, payments are due on the first business day after the 19th of each month in which services were rendered. This results in a 35.1-day lag on payments measured from the mid-point of the month to the date of payment (*i.e.*, between the 20th and the 22nd of each month).

Q. Please describe the treatment of salaries and wages.

A. The Company calculated the lag for salaries and wages, reflecting both weekly and semi-monthly employees, to be 7.7 days. Weekly employees are paid on the Thursday following the week worked resulting in an 8.5-day lag (service period 7 days / 2 = 3.5-day midpoint + 5 days until checks are received). Semi-monthly employees are paid the 15th and the last business day of every month for their prior two weeks worked resulting in a 6.7-day lag.

The two payroll schedules weighted by dollars charged to O&M expense for the 12 months ended December 31, 2018 produce a 7.7-day lag.

Q. Please describe the lag days associated with pensions and OPEBs.

A. A 30-day lag is assigned to fund pension contributions and supplemental expenses. The lag for OPEBs expense was calculated to be 79.5 days. The Company makes three payments annually to the OPEB trust, a 50% contribution on or about August 15th, 25% on or about October 15th, and the remaining 25% on or about December 15th. A mid-point was determined for each of the respective pay periods and then weighted against their payment allocation for total lag of 79.5 days.

Q. How was the lag for the JOA calculated?

A. The JOA expenditures were lagged at 45 days, consistent with the terms of the JOA. The JOA states that payments are due 30 days after the month in which services were rendered. The lag is measured from the mid-point of the month (30 days / 2 = 15) to the date of payment for services (30 days), totaling 45 days.

Q. Please describe the lag associated with uncollectible accounts expense.

A. Uncollectible accounts expense was lagged at 40.4 days, consistent with the revenue recovery lag, to reflect the portion of revenue that is uncollectible.

Q. Please describe the lag associated with other O&M expenses.

A. The lag on other O&M expenses was calculated to be 36 days. This calculation is based on an analysis of accounts payable payments made to vendors for materials and services charged to O&M expense excluding pension and employee welfare expenses. Lag days were measured from the invoice date to the payment date.

Q. Please describe the lead or lag associated with taxes other than income taxes.

A. FICA payroll taxes are submitted to ADP one day before the payroll is run, resulting in a lag of 6.7 days, which is one day less than the salaries and wages lag.

Q. Please describe the lag days associated with New Jersey sales tax ("UTUA").

A. One-half of the UTUA tax is paid on the 20th of the following month for each of the first six months of the year resulting in a lag of 35.3 days. The lag days were calculated using the 15th of each month (*i.e.*, January to June) as the service period mid-point. The remaining 50% of RECO's UTUA liability is paid on May 15th reflecting a lead of 137.8 days (also using the 15th of each month as the service period mid-point). The average for the year results in a weighted average of a 51.3-day lead for this tax.

Q. Please describe the lead or lag associated with Federal and State income taxes.

A. The Federal Income Tax ("FIT") lag assumes four annual payments (*i.e.*, April 15th, June 15th, September 15th and December 15th). We determined that there was a lag of 37.5 days by the number of days that elapsed from the mid-point of the service period (July 1) and the four payments, respectively. The New Jersey Corporate Business Tax ("CBT") 46.8-day lead was calculated by taking the mid-point of the 2015 service period (*i.e.*, July 1) and subtracting each of the three payments on April, May and June 15th, weighted to reflect the percentage of the total tax liability required to be paid on each payment date (*i.e.*, 25% on April 15th, 50% on May 15th, and 25% on June 15th) to determine the net lead.

Q. Please describe the lag days associated with deferred purchased power expense, materials and supplies, amortization expense, deferred federal income taxes, depreciation, and return on invested capital.

A. These components are properly included because they represent Company funded capital, but are assigned a zero lag to the amounts included in the cost of service because they are non-cash items.

ELECTRIC COST OF SERVICE

Q. Please describe Exhibit P-2.

A. Exhibit P-2 contains schedules that show income and rate base for the Test Year, as adjusted, and the required increase in revenue to allow RECO to earn a fair rate of return. Page 1 of 4 of the Summary shows the unadjusted income and rate base for transmission and distribution. Page 2 of 4 of the Summary shows the distribution rate requirement by category. The first column includes adjusted operating income for the Test Year, State and Federal income taxes as calculated on Schedules 21 and 22 of Exhibit P-2, respectively, electric rate base from Exhibit P-3, and the calculated rate of return. The second column provides references to the ratemaking adjustments shown in the third column. The adjustments to the Test Year data are necessary to reflect a cost of service representative of normal operations. These adjustments are described on page 4 of the Exhibit P-2, Summary. The fourth column on page 2 of Exhibit P-2, Summary, shows the cost of service for the Test Year, as adjusted. As shown in this column, RECO's overall rate of return for the Test Year is 1.87%. The fifth column includes the necessary change in distribution rates of $19.9 million required to produce an overall rate of return of 7.56%. This exhibit will be updated as additional actual results become available.

Q. Please describe the adjustments made to the Test Year results shown on pages 1 and 2, in order to arrive at the first column of the Summary.

A. The first column of Exhibit P-2, Pages 1 and 2, are based on actual revenues and expenses with the exception of the income tax calculation. State and federal income taxes were adjusted to reflect these calculations on a ratemaking basis. The interest deduction used in the income tax calculations is based on O&R's total system weighted cost of debt applied to RECO's rate base. Other adjustments were made to the Company's actual income tax calculation to eliminate normalized Schedule M additions, deductions and their related deferred income tax that do not impact the total income tax expense.

Q. Who are the witnesses responsible for the cost of service adjustments shown in the third column of Exhibit P-2?

A. We (the members of the Accounting Panel) are primarily responsible for all adjustments included in Exhibit P-2.

Q. Please begin and explain adjustment No. 1

A. Schedule 1 contains two components. The top part of the schedule shows the adjustment necessary to eliminate the effect of weather-related sales on revenue. This adjustment decreases the six months of actual distribution revenue for the period October 2018 – March 2019 by $604,000 representing weather-related sales of 10,621 MWhs. The bottom part of the schedule shows the adjustment required to annualize the Storm Hardening Surcharge approved by the Board (BPU Docket ER18101114) that went into effect on April 1, 2019. This adjustment increases the actual distribution revenue for the period October 1, 2018 through March 31, 2019 by $176,000. The Company's revenue forecast for the months of April through September 2019 includes projected revenues from the storm hardening surcharge.

Q. Please describe adjustment No. 2.

A. This adjustment to revenues reflects the annualization of revenues and related expenses to reflect the projected number of Service Class No. 1, 3 and 5 residential customers and Service Class 2 customers at September 30, 2019. The revenue annualization was calculated for each class by taking the difference between the average number of customers for the Test Year and the number of customers at the end of September 30, 2019. This difference was multiplied by the average usage for each class to determine the incremental sales associated with the Test Year customer additions. These additional sales were then multiplied by the average distribution rate (net of sales and use tax) for each class to determine the amount of revenue attributable to these sales. The revenue annualization for added new customers is $130,000. The adjustment to expenses of $45,000 reflects the customer costs developed in the Electric Rate Panel's embedded cost of service study for each class multiplied by the additional revenues added during the Test Year.

Q. Please continue.

A. Adjustment No. 3 in the amount of $185,000 reflects the three-year average level for other operating revenues for calendar years 2016 - 2018. The average was normalized to eliminate items that are reconciled with actual customer revenues (*i.e.*, Renewable Energy Credits, Societal Benefit Charge, Transitional Bond Cost, and the impact of the tax law changes).

Q. Does RECO expect an increase in wages and salaries beyond that reflected in the Test Year?

A. Yes. There will be a known and measurable increase in wages and salaries for O&R employees, a portion of which is allocable to RECO. The increases are known because they are a result of contracted wage increases pursuant to labor contracts for weekly paid employees and annual increases for semi-monthly paid employees and adjustments for new positions that were approved by the NYPSC in the last O&R electric base rate case. These employees and positions support the provision of service to RECO's customers; RECO does not have operating employees of its own. In the testimony below, we demonstrate that the amounts of the increases are readily quantifiable and reasonable.

Q. Please describe your quantification of the expected increase in wages.

A. We determined the expected increase in wages by means of two separate calculations. First, we determined the increase resulting from the projected escalation of wages as applied to historic wages (*i.e.*, twelve-month period from October 31, 2018 through September 30, 2019). The result of this calculation is shown on Exhibit P-2, Schedule 4, Page 1 of 2. Then, in a separate calculation, we determined the amount of incremental wages and wage escalation applicable to fifteen additional employee positions addressed in this proceeding. All fifteen positions, *i.e.*, nine management and six weekly positions, were approved by the NYPSC in the last O&R electric base rate case. The Order Adopting Terms of Joint Proposal and Establishing Electric Rate Plan for Orange and Rockland Utilities, Inc. issued by the NYPSC on March 14, 2019 in Case 18E-0067 ("2019 O&R Rate Order"), sets forth the reasons for the addition of these positions. The 2019 O&R Rate Order is available at:

http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={AB70D04D-917A-40A2-8E88-2D2271AD2BD5}

The RECO portion of these employees' expense, are included in this proceeding. The actual and expected hiring dates for these fifteen positions are set forth in Attachment A to this testimony. Since the hiring dates for these fifteen positions are expected to occur during the Test Year, the total twelve-month wages and benefits costs for these positions were not part of the Test Year expenditures. Our calculation accounts for the normalized twelve-month costs associated with these fifteen positions.

Q. Please describe your first calculation as summarized on Exhibit P-2, Schedule 4, Page 1 of 2, regarding the escalation of historic labor expense for projected wage increases.

A. Exhibit P-2, Schedule 4, Page 1 of 2, shows the calculation in support of Adjustment No. 4(a) in the amount of $581,000, for both weekly and semi-monthly paid employees. In developing the amount of budgeted wage increases resulting from projected wage escalation as applied to Test Year wages, we analyzed the historic labor cost of the O&R system (*i.e.*, RECO and O&R), on a consolidated basis, for the twelve months ended December 31, 2018. The analysis separately identified those wages applicable to weekly paid employees and semi-monthly paid employees. Then, using the actual and budgeted wage increase percentages applicable to each group, we calculated the amount of total wages that represent base pay versus wage increase amounts. We then focused on the wage increase amounts and calculated the portion of such wage increase that is applicable to RECO.

Q. What wage increase percentages were used?

A. The wage increases for the weekly paid employees include the effect of the actual June 1, 2018 contracted wage increase of 3.0%. This wage increase percentage was established in O&R's negotiated bargaining unit labor agreement with the Local 503 of the International Brotherhood of Electric Workers, which represents O&R's bargaining unit employees. On February 22, 2017, the Company and Local 503 reached a new collective bargaining agreement. The agreement will be in effect until May 31, 2019. The Company included an estimate for the June 2019 wage increase and will update this schedule to reflect the impact of the new bargaining unit contract when known. The wage increases for semi-monthly paid employees include the effect of wage increases of 3.0% which became effective April 1, 2019 and an expected wage increase of 3.0% to become effective on April 1, 2020. The projected semi-monthly employee increase was based on an assessment of the overall economic outlook, as well as consideration of historical increases.

Q. Please describe your calculation as summarized on Exhibit P-2, Schedule 4, Page 2 of 2, regarding the wage increase related to additional employee positions requested in this proceeding.

A. The electric rate plan approved by the 2019 O&R Rate Order covers the period January 1, 2019 through December 31, 2020. In approving this rate plan, the NYPSC approved certain additional employee positions, fifteen of which have costs allocable to RECO. The costs of six weekly and nine semi-monthly positions are allocated, in part, to RECO as a result of the functions and duties of these positions, as described below. Therefore, the normalized twelve-month costs of these positions are included in this rate filing and are set forth in Attachment A to this testimony. The wage increase amounts summarized on Exhibit P-2, Schedule 4, Page 2 of 2, in the amount of $131,000, include the portion of the salary expense of these positions that is allocated to RECO and the escalation, calculated at the wage increase rates stated above, as applied to these salaries. The Company calculated the amount of salary and escalation allocated to RECO separately for each new position based on the specific job-related duties of each position. A listing of these new positions is also set forth in Attachment A to this testimony. The wage increase amounts summarized on Exhibit P-2, Schedule 4, Page 2 of 2, also include the portion of the salary expense of these new positions that is allocated to RECO and the escalation, calculated at the wage increase rates stated above, as applied to these salaries. The amount of salary and escalation allocated to RECO was calculated separately for each new position based on the specific job-related duties of each position.

Q. What is the basis for inclusion of the costs of the fifteen employee positions that are listed on Attachment A to this testimony?

A. The fifteen positions and brief descriptions of their functions in enabling the Company to provide reliable service are as follows:

- Four Equipment Technicians – The technicians will perform work necessary to support RECO's increasing electric distribution automation and resiliency efforts. An Equipment Technician's duties include, but are not limited to, performing any work required for the operation and maintenance of all field installed reclosers, motor operated air break ("MOAB") switches, regulators, sophisticated (smart) capacitor bank controller, supervisory controls, communication systems including Supervisory Control and Data Acquisition ("SCADA"), sectionalizers, load loggers/recorders, and other meters associated with engineering studies in the overhead and underground system.
- Two Substation Operations Employees – The Substation Operations department is responsible for all the substation facilities throughout the System. Responsibilities include real time operation and maintenance,

maintaining system reliability, and physical site/security maintenance. The Substation Operations department is also responsible for addressing real time issues that arise at System substations and for investigating and responding to equipment issues as they occur. Many of RECO's Substation Operations response, maintenance, and testing requirements are driven by compliance and regulatory requirements. As the compliance and regulatory requirements have increased, there has been an increase in work load on the existing Substation Operations organization which necessitated two additional employees.

- Underground Engineer - From the distribution perspective, a growing number of projects are being designed to place portions of existing overhead circuits underground to minimize exposure to outage sources such as high winds or falling tree limbs that could affect multiple circuits simultaneously. In addition, underground distribution circuit substation outlets are significantly increasing in length to provide path diversity for circuits and to reduce exposure to outage sources to improve system reliability. These circuit outlets have gone from under 1,000 feet of total length to lengths of over one mile.

  The issues described above necessitated the addition of an Underground Engineer. This engineer will be responsible for the design, approval requirements, and construction oversight for various project installations, with dedicated focus on underground projects.

- SCADA Engineer – The Company embraces the opportunities and challenges generated as the electric industry continues to evolve, to include changes in customer desires, advancements in technology and the penetration of distributed energy resources ("DER"). As part of this transformative period in the industry, there is an increase and ongoing need for situational awareness and control which will require systems and applications to acquire data and produce actionable information in a near real-time environment. The SCADA engineer will support the Company's implementation of an Advanced Distribution Management System ("ADMS") platform, the foundational system platform that will integrate critical systems and data that will facilitate the functionality needed to implement advanced grid modernization, enhanced system reliability and efficiency.

- DER Integration Financial Analyst – The Financial Analyst responsibilities will include assisting in the development of Company strategies, policies, and operational procedures to address emerging new DER and Distributed System Platform ("DSP") technologies and projects. The Financial Analyst will also assist in developing other internal financial analysis such as customer bill impacts, as well as the regulatory reporting associated with new DER and DSP projects.
- Two Technical Programmers – When initially established, the primary responsibility of the Customer Systems department was to develop, implement, and maintain the Customer Information Management System ("CIMS"). However, over the past several years, the department's responsibilities have expanded significantly and now include developing and implementing new systems, and maintaining numerous others (*e.g.*, field order routing and design system and associated wireless applications, daily meter reading applications, a new construction project management system). The department is also responsible for customer

systems related disaster recovery preparation, Personally Identifiable Information ("PII") protections and cyber security planning. The combination of RECO's ongoing effort to implement new technologies and automate processes will continue to place additional strain on the Customer Systems department. The two Technical Programmers will have the knowledge and expertise in technical programming and will serve as an additional resource to code and test system enhancements.

- New Business Service Engineer – will be responsible for supporting the process of interconnecting and energizing DER projects, specifically, distributed generation, photovoltaic, and electric vehicle charging installations. The Company expects that the trend of new projects related to these various programs will increase in the future. The responsibility of this engineer will be to provide technical expertise, from inception to completion, for all customer project requests.
- Two Corporate Communications Network Operations Support personal – The Company is expanding its corporate fiber optic infrastructure to electric substations and radio towers across the System. The design will address major bandwidth constraints and allow for the reliable communications needed to support the increased data communications demands that will result from RECO's field automation efforts. The fiber optic infrastructure expansion will offer increased reliability, network capacity and cybersecurity controls at all fiber and data communication facilities under this plan. Once upgraded, these facilities will act as high-capacity data networking access points and will become part of the Corporate Communications Transmission Network ("CCTN"). CCTN is

comprised of the Company's fiber optic and microwave systems and is the Company's data communications backbone for high-capacity connectivity to all data centers and server farms. As the Company expands its automation programs, the CCTN will play a major support role. The Company's CCTN will support and secure sensitive data for several critical systems and functional applications, including Smart Grid, AMI, ADMS, and Energy Management System applications.

The fiber and data expansion will take place within highly restricted and secured areas where only qualified and vetted employees are permitted access. The additional work necessitated the need to hire two additional communications technicians.

- Information Technology Planning – This position will be responsible to develop the design criteria for the fiber optic expansion requirements. This position will be the sole optical design employee for the Company and will team up with the dedicated communications technicians, on all fiber optic expansion projects within Company substations and radio tower facilities. The new employee is also necessary for optical equipment and circuit design. This aspect of the position includes establishing the necessary bandwidth, redundancy, security controls, and disaster recovery specifications across the CCTN.

<u>Annual Management Compensation Program</u>

Q. Please describe the O&R Annual Management Compensation Program.

A. The O&R Annual Management compensation program is a market-based program, base compensation consists of two components, base pay and an Annual Team Incentive Plan ("ATIP") component. Management base pay compensation levels and the ATIP are designed to allow O&R to compete successfully for talent and to encourage the highest levels of performance. Base pay levels for management employees are established through market analysis, which matches Company job related duties and responsibilities with comparable positions in the New York metropolitan area job market.

Base pay is increased by an annual merit increase, which is available to all management employees. The average merit increase is determined annually at the corporate level. The merit increase percent assumed in this case for management employees is 3.0% and is based on the general economic outlook and consideration of historical increases. Merit increases are awarded to individuals based on the assessment of individual employees' performance during the year, including individual accomplishments, skill development and expanded responsibility. Employee performance assessments are made pursuant to a formal corporate performance assessment procedure. The merit increase percentage is intended to represent only part of the total targeted annual increase.

Q. Please describe the O&R ATIP.

A. The compensation of management employees may be increased by awards, if earned, pursuant to the O&R ATIP. The ATIP is an integral component of the compensation provided to management employees. ATIP awards, which are reviewed and approved by the O&R Board of Directors ("O&R Board"), are based on actual performance relative to pre-specified corporate and departmental annual goals. A portion of the costs associated for both O&R base pay and ATIP is allocated to RECO, and is reflected in the historic cost elements in this proceeding and in the labor increases described earlier in this testimony.

The annual ATIP amount allocable to RECO is included on Exhibit P-2, Summary, Page 2 of 4, in Other Operation and Maintenance Expenses. The amount of ATIP allocable to RECO in the historic test period equals $1,002,000. The wage increases for the ATIP program are included in Exhibit 2, Schedule 4, Adjustment 4 described above.

Q. Please continue with a description of the ATIP.

A. The ATIP represents the portion of the total annual base pay that is dependent upon the attainment of certain predetermined, measurable corporate and individual goals. In linking a portion of annual base compensation to defined and measurable performance criteria, the O&R compensation philosophy strives to reward each employee's contribution to the provision of reliable service to the customer and the financial and operating strength of the Company.

The ATIP is structured so that non-officer management employees must contribute to the Company's achieving specific, objective performance goals in order to earn their full base compensation. The ATIP is available to all management employees and includes a fixed team-based award and a variable individual award. The fixed team-based award represents 60% of the total available award and the variable individual award represents 40%. Each employee's individual award is based on that individual's contribution toward the departmental, organizational, or overall corporate initiatives and achievement of goals, and on his or her position in the salary structure of the Company. ATIP goals are established annually and include both financial and operating targets. The O&R Board approves the corporate goals, employee award targets, and the corporate award at the end of the plan year. The O&R Board may, at its discretion, and in consultation with the O&R Chief Executive

Officer, adjust ATIP awards plus or minus 25% to reflect strategic and other factors affecting business operations and results. The O&R Board also may make other adjustments it deems appropriate based on a participant's performance.

Q. Does the Company's compensation structure, including the ATIP, benefit customers?

A. Yes, O&R's current compensation structure, including the ATIP, plainly benefits the Company's customers, particularly as compared to a base pay only structure. Full payment of market-competitive compensation is contingent upon the employees collectively and individually achieving a comprehensive, defined set of goals that will have immediate and long-term direct and indirect benefits to customers. In our testimony below, we describe the specific goals of the ATIP and the customer benefits of each in more detail. Furthermore, the ATIP is consistent with programs offered to non-officer management employees by other companies that compete with O&R in the recruitment of management employees. The provision of safe, adequate and reliable service to customers depends on the competitively compensated, highly qualified and motivated employees that the Company has been able to hire and retain due in part to the ATIP.

Q. Please describe the ATIP goals for 2019.

A. Set forth in Attachment B to this testimony is a description of O&R's 2019 ATIP goals.

Q. How do RECO's customers benefit from the attainment of Customer Service Performance ("CSP") goals?

A. Achievement of the CSP goals benefits customers by enhancing reliability of service, safety, customer service, pro-environment practices, employee development, storm response, and completion of system enhancements and capital projects. To the extent that the CSP goals are achieved, customers will recognize direct benefits, including improved service reliability.

Q. How do RECO's customers benefit from the attainment of the Earnings, Operating Budget, and Capital Projects goal?

A. RECO's customers benefit both directly and indirectly when the Company achieves its Earnings, Operating Budget, and Capital Projects goal. Customers derive benefits from achieving the net income levels that attest to the Company's financial strength and stability. O&R (and RECO) compete for capital in a capital-intensive industry. A well-run company that attains rigorous financial and operating budget goals will ultimately benefit its customers, by allowing it to attract capital at reasonable costs.

Q. How are the customer benefits of such goal attainment reflected in the Company's operating projections in this case?

A. The financial and operating benefits of attaining these operational and financial goals are embedded in the Test Year and the forecasted data presented in this case in the form of lower costs and higher productivity. Achievement of the Capital Projects goal allows the Company to replace and enhance the system were appropriate in order to continue to provide safe and reliable service.

Q. How have the benefits of achieving the operational objectives that determine incentive compensation been reflected?

A. As we have demonstrated, the Company has achieved a higher level of customer service that is inherent in goal attainment levels. The attainment of the incentive goals contained in the ATIP, as described above, demonstrates enhanced performance (as witnessed by the level of goal attainment) translating into enhanced productivity and lower costs.

Q. Is there any other information, beyond the benefits of achievement of the goals you described above, which supports the Company's recovery of ATIP costs as part of its operating expense?

A. Yes, there are two additional considerations that demonstrate the reasonableness of the ATIP expenditures. First, the ATIP has been an integral driver of RECO's overall success in providing safe and reliable service, including significant strides in initiatives like emergency response, and maintaining a satisfied customer base, by motivating the collective efforts its management employees.

Second, the ATIP has a substantial history of being part of RECO's compensation structure. The program's costs are an inextricable part of the cost of RECO's utility service and a key component of the Company's success in delivering excellent service to customers. It would therefore be arbitrary for the Board to retain for customers the clear benefits that the ATIP has provided to them (including enhanced service at lower costs) while at the same time disallowing recovery by RECO in rates of the ATIP costs that have indisputably led to these benefits.

Q. Please address adjustment No. 5.

A. The adjustment of $123,000 for health and benefit insurance costs was made to reflect the impact of higher benefit premiums the Company is anticipating for next year. We calculated the estimated increase in 2019 health insurance premiums by applying RECO's current fringe benefit rate for health insurance and workers' compensation premiums to the wage increases shown on adjustment No 4, page 1 of 2, for the salaries for new employees as noted in the discussion regarding adjustment No. 4, page 2 of 2 above, as well as, reductions made for the number of meter readers as shown in adjustment No. 10.

Q. Please describe the Company's employee health and benefit insurance benefit plans.

A. The Company's employee benefit insurance plans include medical, dental, prescription drugs (card and mail order), vision, Health Maintenance Organizations ("HMOs"), life insurance, disability, accident and sickness, and accidental death and dismemberment. The amounts included in Exhibit P-2 are net of amounts to be (i) capitalized, (ii) billed to others, and (iii) recovered from employees and retirees.

The Company requires (i) current employees, (ii) former employees under the provision of the Consolidated Omnibus Budget Reconciliation Act of 1985 ("COBRA"), (iii) retirees, and (iv) surviving spouses to contribute to the cost of their health insurance coverage. Actual premiums, claims and reimbursements will be updated during the course of this proceeding. The Company makes several life and health insurance programs available to employees, retirees, their dependents, and spouses of deceased employees and retirees, in which the individual makes payment of the insurance premium. Spouses of deceased active employees and of retirees are offered optional continuation of benefits and are billed 50% of the premium for this coverage. Also included in this category are contributions made by employees and retirees for health coverage. For employees, the contribution amount is based upon a premium sharing depending upon the coverage elected (*i.e.*, employee only, employee plus one dependent, employee plus two or more dependents). Contributions are based on a cost share strategy determined by the Company and for hourly employees, the provisions of the Company's current Bargaining Unit Contract determine the contribution rates that are paid by the hourly employees. For the majority of bargaining unit retirees, the contribution amount is "frozen" at the rate they were paying at the time of their retirement and stops at age 65. The bargaining unit contract that was effective June 2014 and then extended through May 31, 2019, provided for contribution increases for under age 65 retirees through 2017 with no additional increases for those who retired in 2015 through 2019. Retiree contributions remained the same from January 2017 through 2019, as a result of an extension of the Local 503 collective bargaining contract. The same methodology was applied to the over age 65 retirees who retired in 2015, 2016, and 2017 as they began to contribute to the retiree health program in 2015 with increases being applied in accordance with the collective bargaining process through 2017. For management employees, it was determined that the Company would freeze their contribution levels for retiree health coverage at the 2013 rate and retirees would absorb 100% of the costs associated with any increases related to the retiree health plan.

Q. How does the Company administer its medical benefit plans?

A. Currently the Company is fully insured for the medical benefits offered to hourly employees, self-insured for the prescription and dental coverage and self-insured for the majority of health benefits offered to management employees and retirees. The bargaining unit employees are offered four plan options provided by CIGNA including a high deductible health care plan and an essential health plan with a health care savings account option. Management employees, along with the under age 65 retirees, are covered by plans currently administered by CIGNA with the management employees also having four CIGNA plan options, along with choices for an HMO plan. All retirees over age 65 are provided a Supplement to Medicare Plan that is self-insured and administered by CIGNA with a Medicare Part D prescription drug plan including a wrap plan administered by Silvercript which provides for the gaps in the Medicare Part D program.

Q. How does the Company manage its prescription, dental and vision insurance costs?

A. Prescription, dental and vision benefits for employees have been carved out of the medical plans and are handled by Caremark, MetLife and Comprehensive Professional Systems, respectively. Coverage for employees is provided through self-insured indemnity type plans and co-payments and deductibles are reviewed each year to determine if plan design changes are needed.

Q. What changes has the Company made within the benefit plans over the last several years to mitigate health and welfare costs?

A. The Company has taken numerous steps to contain and mitigate health and welfare costs. During 2013 and again in 2017 for management employees and in 2015 and 2018 for bargaining unit employees, the Company introduced consumer-driven high deductible health plans which are expected to mitigate future health care cost increases to change employee behavior toward being better consumers of health care services. The Company is placing an increasing emphasis on promoting healthy behavior to mitigate health care costs in the future. For the last several years during open enrollment, management and Local 503 employees were asked to participate in some wellness initiatives. Cigna, our hospital/medical insurance carrier, collected health information from employees to assess the general health of our employee population and recommended future wellness programs and incentives that encourage employees to participant in health improvement activities. Employees and their enrolled spouse were offered a monetary incentive to complete a health assessment. This is a tool CIGNA uses to obtain baseline health information as well as to provide employees and their spouse with insight into their health status and an action plan to address any potential health risks. Management employees receive an incentive of $5.00 per pay period credit for their own health assessment and another $5.00 per pay period credit if their spouse completes the health assessment. Under the Labor Contract, Local 503 members will receive an incentive of $3.00 per pay period for completing the health assessment and another $2.00 per pay period credit if their spouse also completes the health assessment. In addition, management employees receive an incentive of $5.00 per pay period if they take a basic medical screening that includes blood pressure, cholesterol, blood sugar and body mass index, all of which are essential for identifying potential health issues. Management employees will receive another $5.00 per pay period incentive if their enrolled spouse also takes a medical screening. Under the Labor Contract, Local 503 members will receive an incentive of $3.00 per pay period if they take a basic medical screening and another $2.00 per pay period if their enrolled spouse also takes a medical screening. The Company’s 2019 wellness initiative continues to include a surcharge for tobacco usage for both management and Local 503 members, which has a direct correlation to increased health risks leading to higher medical costs. Employee who voluntarily identify themselves as tobacco users or who do not complete the tobacco usage question during open enrollment will be required to make an additional $240 payroll contribution toward their health care coverage each year. An employee who is a tobacco user can avoid eth additional health care contribution by enrolling in a tobacco cessation program. Under the Labor Contract, Local 503 members will also be subject to a $3.00 per pay period tobacco surcharge for themselves and their covered spouses.

The Company added a new High Deductible Health Plan in 2017 for management employees and in 2018 for Local 503 employees as a medical plan choice for participants called the Essential Health Plan. It features a $2,500 deductible for individuals, $5,000 deductible for families with 80 percent coverage of expenses. There are no required monthly contributions for management employees so that all employees have a level of catastrophic coverage and minimum weekly contributions for Local 503 employees. The Company does not contribute to the HSA account, but the participant does have the ability to contribute up to the IRS limits. The Company expects that the addition of this lower cost plan option will increase participation in the High Deductible Plan options offered and encourage employees to be more prudent in evaluating medical options which will help offset future medical cost increases. Each year the Company has increased the employee cost share corresponding to each option by increasing in- and out-of-network deductibles, applying coinsurance for in-network service and increasing co-payments for primary care and specialist office visits. The healthcare contribution cost share has also been steadily increased and management employees contribute approximately 25% as of 2018 toward the cost of their healthcare coverage. The target cost sharing percentage that union employees will contribute to the cost of their healthcare is 25% as negotiated in the bargaining unit contract and is expected to be at 23% by the end of 2019. Co-payments and deductibles in the bargaining unit plans for each health plan option have also increased throughout the term of the contract. For example, the co-payment for a primary care office visit increased from $20 in 2014 to $25 in 2019 and a specialist co-payment also increased during this contract starting at $25 in 2015 to $35 for 2019 for the co-payment medical plan option. In order to control dental plan costs, the Company added deductibles for in-network dental services, as well as increased the deductibles for the out-of-network services. As a result of ongoing vendor management, the Company negotiated additional savings with regard to the prescription drug pricing it receives from its contract with CVS Health who is the administrator of the prescription drug program.

Q. Does CVS Health offer any programs to assist employees to better manage their prescription drug costs?

A. Yes, for those employees or dependents with chronic and genetic disorders, there is a separate Specialty Pharmacy program, administered by CVS Health, which manages the dispensing and use of high-cost specialty drugs. Specialty medications make up one third of the total pharmacy costs. Specialty Pharmacy programs manages numerous health conditions, including Crohn’s disease, cystic fibrosis, macular degeneration, multiple sclerosis, Hepatitis-C and other serious health conditions. The Company has also worked with CVS Health to identify prescription drug trends that increase costs, such as the use of compounds when filling certain prescriptions. CVS Health works with the Company on a regular basis to develop strategies and authorization processes for new drug trends that have the ability to increase the Company’s costs.

Q. Have all of these plan design changes been effective in the control of cost increases?

A. Yes. Through offering choice and introducing innovative plan designs such as the high deductible plan, the Company has seen a lower health care trend than in previous years. Through education and marketing efforts, the Company has been able to assist employees with their benefit choices and currently have approximately 60% of the management employees enrolled in a high deductible plan which shifts the initial medical costs including prescription drug cost to the employee. Further, significant reductions have also been achieved by capping medical payments to retirees, which we will discuss later in our testimony when we explain Exhibit P-2, Schedule 7. Nonetheless, the balance of these costs has increased and remains a significant cost of RECO's business.

Q. Please describe the term life insurance and Accidental Death & Dismemberment ("AD&D") benefits offered by Orange and Rockland.

A. For management employees, AD&D life insurance is provided in the amount of $50,000 and the union employees receive AD&D life insurance in the amount of $15,000 per employee. Hourly retirees currently receive a Company paid life insurance benefit of $12,500 and management retirees are provided a life insurance benefit of $25,000. As of January 1, 2013, retiree life insurance is only offered to management employees/retirees at retirement who were at least 50 years old as of January 1, 2013 and who meet the eligibility for retirement. Active management employees are provided group term life insurance equal to 1.5 times their salary to a maximum of one million dollars and active union employees are provide with group term life insurance in the amount of two times their salary up to a maximum of $150,000.

Q. Certain of the medical costs described above also relate to retirees such as health and life insurance, and prescription drug costs. Are these costs included in Exhibit P-2, Schedule 7?

A. Yes. Exhibit P-2, Schedule 7, contains the retiree claim payments made by the Company, net of reimbursements from the VEBA Benefit Trusts. Exhibit P-2, Schedule 5, excludes all of these payments.

Q. When did the Company introduce employee contributions?

A. For hourly employees, contributions were introduced in 1991 as a result of the 1988 contract negotiations with Local Union 503 of the International Brotherhood of Electrical Workers. For management employees, contributions were introduced in 1995.

Q. Please describe adjustment No. 6.

A. Exhibit P-2, Schedule 6, shows a net reduction for employee pension expense of $189,000. The adjustment reflects the reduction to pension costs for calendar year 2019 when compared to the Test Year based on the actuarial determination provided by the Retirement Plan actuary, Buck Consultants, dated March 2019. The Company applied the RECO common expense allocation of 17.23% to the projection of O&R pension expense for the 12 months ending December 2019. This actuarially determined level of expense was offset by the projected capitalized level of expense based on the historic ratio of 39.8% to produce $3.2 million of net pension costs for the 12 months ending December 2019. When compared to net pension expense for the 12 months ending September 2019, based on a forecast that included six months of actual data, net pension expense decreased by approximately $206,000. The distribution portion of this decrease produced a reduction of net pension expense of $189,000.

Q. Please describe the Accounting Procedures followed by the Company to record Pension costs.

A. The Company accrues its Pension obligation based on actuarial studies that are performed in accordance with SFAS 87 (ASC 715).

Q. Please explain what steps the Company has taken to limit and reduce current and future pension costs?

A. The Company's Retirement Plan is a defined benefit pension plan which originally provided vested employees with pension benefits under a Career Average Pay ("CAP") pension formula. Over time, the Company has amended the Retirement Plan several times and implemented changes to the pension formula and other plan features to mitigate the growth in future liabilities and costs. For example, the Company amended the Retirement Plan by changing from the CAP pension formula to a Cash Balance pension formula for management employees hired between January 1, 2001 and December 31, 2016 and union employees hired between January 1, 2010 and May 31, 2014. The Company closed the Retirement Plan to management employees hired on or after January 1, 2017 and union employees hired on or after June 1, 2014. Pension benefits for management employees hired on or after January 1, 2017 or union employees hired on or after June 1, 2014 are provided under a defined contribution pension ("DCP") formula in the Thrift Savings Plan. The cost of providing pension benefits to employees covered by the Cash Balance or DCP formula is lower than the cost of providing pension benefits under the traditional CAP pension formula mainly due to lower benefit accrual rates and the elimination of cost-of-living adjustments and early retirement subsidies. Another Retirement Plan change to the benefits provided under the CAP formula for management employees was made effective January 1, 2013, further reducing future pension liabilities and annual pension costs associated with subsidies for early retirement for management employees retiring after January 1, 2013. Instead of receiving an unreduced pension for retiring before age 60, employees are subject to a five percent per year reduction from ages 55 to 60.

The DCP formula is a “tax-qualified defined contribution retirement plan” and the Company will contribute each calendar quarter a “compensation credit” to a covered employee’s Thrift Savings Plan account. The compensation credit amount is based on the employee’s compensation during the quarter, age, and years of service, as shown in the following table:

Age plus years of service	Compensation Credit
Less than 35	4%
35 to 49	5%
50 to 64	6%
65 or more	7%

In addition, an employee’s compensation credit includes an additional four percent credit on compensation in excess of the Social Security Wage Base (*e.g.*, $128,400 for 2018). Under the plan, employees direct the investment of the funds in their DCP account in an array of investment options and assume the investment risk and rewards associated with long-term investing. The Company’s DCP contribution for an employee who does not make an investment election is invested in the plan’s default investment fund — currently the Vanguard Target Date Fund - that assumes the employee will retire at age 65. Employees in the DCP formula are 100% vested in the Company contribution. Employees are not permitted to receive their DCP account balance while they are employed at the Company. Upon leaving the

Company, employees can elect to receive their vested DCP account balance as either a lump sum or in installment payments made for a fixed period of time. Guaranteed lifetime annuity payments are not available. We expect that the pension cost of employees covered under the DCP formula will be slightly less than the cost under the Cash Balance Pension formula. In addition, this change positions the Company to mitigate the investment and longevity risks associated with managing the Retirement Plan and eliminates the risks associated with funding pension benefits for future employees.

Q. Please describe the costs included in Exhibit P-2, Schedule 7.

A. This exhibit shows the Company's adjustment to expense necessary to reflect known SFAS 106 OPEB costs for the 12 months ending December 31, 2019. The adjustment reflects lower OPEB costs based on the actuary letter provided by Buck Consultants dated March 2019. The Company applied the RECO common expense allocation of 17.23% to the known O&R OPEB expense for the 12 months ending December 31, 2019, as shown in Table 1 of the actuary study. This actuarially determined level of expense was offset by the projected capitalized level of expense based on the historic ratio of 39.8% to produce $9,000 of net OPEB costs for the 12 months ending December 2019. When compared to net OPEB expense for the 12 months ending September 30, 2019, based on a forecast that included six months of actual data, net OPEB expense decreased by approximately $126,000. The distribution portion of this decrease produced a reduction to net OPEB expense of $116,000.

Q. What steps has the Company taken to control OPEB costs?

A. The Company has taken a variety of steps to reduce its net periodic costs. For example, in 2006, the Company adopted the federal retiree drug subsidy

("RDS") program for its prescription drug plan for Medicare-eligible retirees. Under the RDS, the Company received a federal tax-free subsidy for maintaining a retiree prescription drug benefit that equaled or exceeded the actuarial value of standard prescription drug coverage provided under the Medicare Part D program. The RDS subsidy was used to offset Retiree Health Program OPEB costs. Later, as the Affordable Care Act eliminated the tax-free status of the RDS subsidy to employers effective January 1, 2013, the Company implemented an Employer Group Waiver Plan ("EGWP") for its Medicare-eligible retirees, which has resulted in greater OPEB cost savings than the direct RDS subsidy. Under the EGWP, CVS Health, the pharmacy benefits manager, contracts directly with the government prescription drug program. CVS Health handles all administration and federal interactions and collects the RDS subsidy for the Company's retiree drug plan. In addition, the Company receives the benefit of lower costs attributed to the Coverage Gap Discount Program and other direct subsidies provided under the Affordable Care Act.

The Company made further changes in 2013 and eliminated its retiree health program subsidy for all management employees retiring under the Cash Balance and Defined Contribution pension formulas. Management employees who meet the eligibility requirements of and enroll in the Retiree Health Program will be responsible for paying the full cost of Retiree Health coverage offered through the Company. The Company also implemented a cost-sharing formula in 2014 for management employees retiring under the CAP pension formula. Under the cost-sharing formula, the Company's contribution toward program costs is limited to its contribution in the preceding year plus inflation as measured by the change in the CPI. Contributions for retirees increase if Retiree Health Program cost increases are above CPI. Similarly, a retiree contribution change reducing OPEB liabilities and costs was also negotiated for union employees under the labor contract with Local 503. Employees hired on or after January 1, 2015 will be required to pay 50 percent of the premium cost if they are eligible and enroll for retiree health coverage when they retire. The Company also negotiated an increase in the eligibility requirements for Retiree Health coverage for future retirees from age 55 with ten years of service to age 55 with 20 years of service which is also expected to reduce future OPEB costs.

Q. Please describe the reason for the decline in the OPEB costs.

A. The decline in OPEB costs from the 12 months ending September 30, 2019 to the 12 months ending December 31, 2019, is primarily driven by an increase in the discount rate from 3.70% in 2018 (which was used for the calculation of cost for the 2018 portion of cost for the 12 months ending September 30, 2019) to 4.30% in 2019.

Q. Please describe the accounting procedures followed by the Company to record OPEB costs.

A. The Company accrues its OPEB obligation based on actuarial studies that are performed in accordance with the provisions of SFAS 106 (ASC 715).

Q. Please address adjustment No. 8.

A. This adjustment to O&M Expenses is necessary to reflect the interest on customer deposits. This expense adjustment of $55,000 reflects the Board rate of 1.87% that will be in effect for calendar year 2019 on the $2,941,000 of customer deposits included in rate base.

Q. Please continue with adjustment No. 9.

A. This adjustment to O&M Expenses reflects the recovery of costs associated with this proceeding. RECO has estimated $600,000, including legal and consulting fees and other costs, as the amount necessary to establish RECO's new base rates. In addition, RECO proposes to recover an under-recovered balance of $6,250 from BPU Docket No. ER16050428, as authorized in the February 2017 Rate Order (p. 5). RECO proposes to recover these costs over a three-year period resulting in an increase in O&M Expenses of $180,000.

Q. What is the rationale for a three-year amortization period?

A. This period reflects the Company's anticipation that it may need to refile for new rates within three years. The period is reasonable in view of the time frame between recent Company base rate cases.

Q. Please explain adjustment No. 10.

A. Adjustment No. 10 eliminates the cost of AMI expenses included in the test year in the amount of $94,000. The adjustment has two components. The first relates to planned reductions in the number of meter readers required by the Company with the implementation of AMI metering. Since October 1, 2018, the Company has reduced its meter reading staff by five positions through March 31, 2019. The Company anticipates that it will be able to eliminate approximately one meter reading position each month through September 30, 2019. The actual staffing reductions achieved will be reflected in updates. The adjustment calculates the annual salary savings applicable to the Company for the Test Year of approximately $145,000 and reflects the amount not included in the Test Year of $76,000. Corresponding adjustments to employee benefits and payroll taxes are included in Schedules 5 and 20. The second adjustment of $19,000 eliminates the costs incurred through

March 31, 2019, as a result of replacing old meter pans that could not be reused when the Company replaces old meters with new AMI hardware. The AMI Order required the Company to absorb these costs. The Company will update this adjustment for any additional cost incurred during April through September 2019.

Q. Please address adjustment No. 11.

A. Adjustment No. 11 represents RECO's actual customer uncollectible write-off experience. It was calculated as the historic three-year average of bad debt write-offs as a percentage of revenues for the five-year period ended March 31, 2019. The resultant factor of 0.178% is then applied to the forecasted revenues for the Test Year. The result of $296,000 is compared to the bad debt expense for the Test Year of $368,000, for a decrease of $72,000 from the level contained in the Test Year forecast.

Q. Please describe adjustment No. 12

A. Adjustment 12 consists of two adjustments. The first contains an increase to RECO's danger tree program to address emerald ash borer and other dead and deceased trouble spots. This adjustment is supported by the Capital Budget Panel. Their funding request reflects the fact that there are approximately 17,000 ash trees in RECO's service territory and the emerald ash borer has almost a 100% mortality rate. The Capital Budget Panel indicates that the average cost to remove an ash tree is approximately $700. As a result, the potential exposure to remove every ash tree could approach $12 million (*i.e.*, 17,000 trees x $700 per tree). To initiate the Danger Tree program, the Company is requesting initial funding of $500,000 per year. The second adjustment calculates the increase necessary to fund the Company's

Storm Reserve on an ongoing basis for anticipated major story activity, *i.e.*, from $750,000 to $1.5 million.

Q. Please describe how the Company calculated the requested increase in funding for the storm reserve?

A. The Accounting Panel reviewed actual major storm costs the Company incurred over the last five years. There were seven events that qualified for deferral under RECO's Board-approved storm deferral provision that amounted to approximately $17.6 million in total. (Storm costs for each individual storm qualify for deferred accounting if the storm caused electric disruption for 10% or more of customer in an operating area or if customers are without power for more than 24 hours and incremental costs incurred for each individual storm exceed $130,000, *See* February 2017 Rate Order, p. 5). Expenditures for one storm (Winter Storm Quinn) were viewed as extraordinary based solely on the magnitude of the costs incurred (*i.e.*, $10.1 million). Accordingly, for purposes of setting an annual storm reserve allowance, these costs were eliminated from the calculation. The net remaining costs of $7.5 million represent a level of storm costs that the Company would expect to incur over a five-year period. The annual funding requested to provide for this level of storm activity is $1.5 million annually. Please refer to Statement in Support of Adjustment Number (12b) for the analysis and calculation of the Company's proposal.

Q. What is the Panel's basis for assuming that the level of storm activity incurred over the last five years will continue?

A. As discussed earlier, the Company completed a four-year recovery of what was deemed to be extraordinary storm costs in July 2018 of approximately $25.6 million (*see* BPU Docket No. ER13111135). The rates established by the Board in the February 2017 Rate Order also included an annual funding recovery allowance for the storm reserve of $750,000. While the severity of the damage caused resulting from major storms cannot be estimated with any certainty going forward and the Company's storm hardening program should help minimize the resulting damage, it is not a question of "if" there will be more major storm events in the future, but rather a question of "when."

Q. Please discuss proposed adjustment No. 13.

A. Schedule 13 shows the adjustment required to equalize the JOA billing. The JOA billings are based on a contract ROE of 13.0%. The adjustment of $450,000 is being made to decrease the intercompany billing based on the Company's requested ROE of 10.0%, as discussed in the direct testimony of Company witnesses Vander Weide and Saegusa.

Q. Is an adjustment also required in this Case to equalize PSA Billings to the ROE request by the Company?

A. No, the ROE included in the carrying charges billed in the PSA would be for jointly used transmission plant billed between O&R and RECO, and as such does not impact the distribution revenue requirement.

Q. What is the RECO's proposal regarding the current storm reserve deficiency allowance as outlined in Schedule 14(a)?

A. RECO's Storm Reserve Deficiency is projected to be $13.3 million as of September 30, 2019, based on $17.5 million of storm costs deferred from seven different storms during the period August 2014 through March 2019, net of storm cost recoveries through September 30, 2019 of $4.2 million. The Company has not projected any additional deferred storm costs between April 1, 2019 and September 30, 2019. The Company proposes to amortize these costs over a three-year period or $4,437,000 annually. Please refer to

Statement in Support of Adjustment Number 14(a) for the analysis and calculation of the Company's proposal.

Q. Please explain adjustment 14(b).

A. Adjustment 14(b) reflects the recovery of deferred Management Audit Assessments of approximately $655,000 over three years, which is equivalent to $218,000 annually. These costs are recoverable as proper business expenses pursuant to N.J.S.A. 48:2-16.4.

Q. What is the basis for requesting a three-year amortization period for deferred storm and Management Audit Assessments?

A. As discussed previously, this time period reflects the Company's anticipation that it may need to file for new rates within three years. The period is reasonable in view of the time frame between recent Company base rate cases.

Q. Please describe adjustment No. 15.

A. The current February 2017 Rate Order that the Company is operating under provided for the amortization of a number of net deferred credits over a three-year period. Adjustment No. 15 increases expense by $18,000 to remove the current amortization from rates. While the current amortization is set to expire in February 2018, leaving a credit balance of $1,500, the Company requests permission to write-off this amount given its relatively small size and not extend the current amortization for this item.

Q. Please describe adjustment No. 16.

A. Adjustment No. 16 consists of two parts. The first part shows the calculation necessary to annualize 2019 depreciation expense based on projected plant balances as of September 30, 2019 at currently approved depreciation rates. This calculation results in an adjustment of $199,000. The second part shows the impact of applying the proposed depreciation rates, as sponsored by Company's Depreciation Panel to the annualized depreciation expense resulting in an adjustment that would increase depreciation expense by $656,000. The net of both adjustments would be an increase in annualized depreciation charges of $855,000

Q. Please describe adjustment No. 17.

A. This adjustment to depreciation expense reflects the depreciation accruals on the post-Test Year plant additions. These additions consist of the major projects discussed in the testimony of the Capital Budget Panel and summarized on Exhibit P-3, Schedules 1 and 12. The depreciation adjustment was calculated using the composite depreciation rates proposed by the Depreciation Panel.

Q. Please continue with adjustment No. 18(a) and 18(b).

A. As discussed by the Depreciation Panel, the Company proposes to reduce recovery of expiring depreciation reserve deficiencies that will be fully recovered by February 28, 2020. Please see Statement in Support of Adjustment 18(a). The Company is currently amortizing $463,056 annually. The residual balance to be amortized equates to $43,000 at January 31, 2020. Amortizing this balance over three years would amounts to $14,000 annually. Therefore, adjustment No.18(a) decreases depreciation expense by $449,000 (*i.e.*, $463,000 - $14,000).

In the 2017 Rate Order, the Company was directed to amortize a depreciation reserve surplus of $9.781 million over fifteen years or approximately $652,000 annually (*see* item 11, p. 4, in the Board's Order Docket No. ER16050428). The current amortization is shown on the bottom of Adjustment 18(a) and the

Panel is not proposing to make any changes to the current amortization, which will continue for an additional 12.4 years.

Q. Please continue with adjustment No. 18(b).

A. Adjustment 18b consists of two components. The first portion shows actual and projected negative net salvage costs from January 1, 2017 through September 30, 2019 of approximately $5.2 million. During this thirty-three month period, the Company will have recovered $2.8 million of negative net salvage in rates. This will result in a projected net under-collection of approximately $2.4 million. The Company seeks to increase its current allowance for negative net salvage by $813,000 to recover this shortfall over three years. The second adjustment requested by the Company's Accounting and Depreciation Panels is to use the thirty-three month historic average of negative net salvage (*i.e.*, plant removal costs) in the calculation of the annual level of funding for negative net salvage. In reviewing the historic spending for calendar year 2017, the Accounting and Depreciation Panels ("Panels") noted a large spike in the 2017 spending. The Panels believe that it is appropriate to eliminate negative net salvage expenditures that are not expected to be reoccurring over the next several years when calculating the level of annual spending to be included in rates. As a result, $1.7 million of expenditures related to the removal of the Grand Avenue Substation, RECO's portion of Line 73/74, and removal of the Montvale Substation Switch House were eliminated to determine a normal level of negative net salvage costs to be used in the calculation of the average annual spending levels. After making this adjustment, the Panels determined that $1.279 million would be a normal level of negative net salvage to be incurred on an annual basis. This represents an increase of $255,000 above the level currently in rates. In total the adjustment is reflected as an increase to depreciation expense of $1,068,000 (*i.e.*, $813,000 plus $255,000).

Q. Please explain the purpose of adjustment No. 19.

A. As part of the Company's program to replace existing meters with new AMI electronic equipment, approximately $5.2 million of meters and associated costs will be retired from plant in service and charged against the Company's depreciation reserve. As a result, this equipment will no longer take depreciation expense because the costs will be in the depreciation reserve. The Depreciation Panel has proposed to amortize these costs over 15 years. The resulting increase to depreciation expense amounts to $345,000.

Q. Please continue with adjustment No. 20.

A. Exhibit P-2, Schedule 20, shows the calculation of adjustment for the increase in payroll taxes. The cost was developed by applying the effective payroll tax rate of 7.74% to the amount of the wage increases reflected on Exhibit P-2, Schedule 4, and for reductions to wage expense for the elimination of meter reader positions shown in Exhibit P-2, Schedule 14.

Q. Please describe adjustments Nos. 21 and 22.

A. These two adjustments present the calculation of State and Federal income taxes for ratemaking purposes. Each calculation has two pages. The first page shows the income tax calculation for the twelve months ending September 30, 2019 for transmission and distribution. The second page shows the calculation for distribution and reflects the impact of each adjustment in Exhibit P-2. The first column on each schedule starts with Operating Income Before Income Taxes for the Test Year. Interest charges were deducted to arrive at Book Income Before Income Taxes. Income was then adjusted for those items that are treated differently for book and income tax purposes to arrive at Taxable Income. The New Jersey CBT was computed at the statutory rate and then deducted from Taxable Income to determine Federal Taxable Income.

In column 3 of the second schedules of adjustments 21 and 22, normalization adjustments have been made for the various adjustments reflected on the income statement. We have also reflected the Deferred Federal Income Taxes to be used in determining cost of service for RECO. Finally, we have reflected the Amortization of Deferred Federal Income Tax Credits for Protected Property and Non-Property contained in the TCJA Order, related to the tax rate changes enacted in the 2017 Federal Tax Cut Act, as well as the amortization of Investment Tax Credits.

Q. Please explain how the Company is currently accounting for the Protected Deferred Income Tax Balance of approximately $14.4 million that was addressed in the Paragraph 11 of the TCJA Order.

A. In accordance with the TCJA Order, the Company has reclassified the balance of Protected Excess Deferred Taxes of $14.4 million (grossed up amount) and started amortizing this balance. Since the amortization of the credits for protected property was not reflected in the amounts the Board directed the Company to pass back to customers in the TCJA Order, the Company has been deferring the monthly amortization as a regulatory liability. In addition, as indicated in the direct testimony of the Income Tax Panel, the level of deferred tax credits for non-property has increased by $1.7 million. The Income Tax Panel is proposing to amortize the increase in non-property tax credits with the start of new rates in February 2020 over five months in order to eliminate fully the deferred tax balance by June 2020. An alternative would be to use this credit balance as a partial offset to the increase the

Company is requesting and amortize this balance over three years. This change would lower the rate request by almost $600,000 (*i.e.*, $1.7 million / 3 years).

Exhibit P-3, Schedule 7, column 4, shows that by September 30, 2019 the projected deferred credit balance will be $488,000 for protected property credits. The Company will continue to update this balance during the course of this proceeding.

Q. Paragraph 11 of the TJCA Order indicated that the Company will address any change in the $14.4 million of Protected Excess Deferred Taxes in its next base rate case. Does the Company have any updates to this balance?

A. Yes. As indicated in the direct testimony of the Income Tax Panel the level of deferred tax credits related to protected property is $3.7 million higher than originally estimated (excluding amounts that have been amortized and deferred as a regulatory liability).

Q. What has the Company reflected in this filing for the amortization of protected property and non-protected property?

A. For purposes of this rate filing, the Company has reflected the amortization of $343,000 for protected property (*i.e.*, the level in the TJCA Order), in Exhibit P-2, Schedule 22, as an amortization of Deferred Tax Credits to reduce federal income tax expense. For non-protected property, the Company has also reflected the level included in the TJCA Order in Exhibit P-2, Schedule 22. The amortization of the protected property will be updated in 9+3 to reflect the updated deferred tax credit balances. The Company will also reflect a three-year amortization of protected property credit currently deferred as a regulatory liability (*i.e.*, $488,000).

Q. Please describe adjustment No. 23.

A. This adjustment shows the calculation of the interest deduction used in the tax computations (*i.e.*, adjustments 21 and 22).

Q. Please describe the adjustments shown in column 5 of Exhibit P-2, Summary, Page 2 of 4.

A. The adjustment to revenue of $19.906 million reflects the revenue increase required to produce a 7.56% rate of return calculated by Company witness Saegusa based on her proposed capital structure, as well as the cost of equity capital the Company is requesting of 10.0%. The adjustment to O&M expense reflects the increased uncollectible accounts associated with the proposed increase in revenue. The adjustment to income taxes reflects the additional New Jersey CBT and FIT associated with the proposed increase in revenue. The calculation of these amounts is shown on Exhibit P-2, Summary, Page 3 of 4.

<u>2017 and 2018 Storm Hardening Filings</u>

Q. At the bottom of Schedule 1 of Exhibit P-2 the Accounting Panel included an adjustment to annualize the revenues from the Storm Hardening rate adjustments approved by the Board in Docket Number ER1810114 that went into effect April 1, 2019. Please explain the purpose of this adjustment**.**

A. As mentioned above in describing the bottom portion of Exhibit P-2, Schedule 1, an adjustment to annualize the 2019 Storm hardening revenue is necessary in order to reflect the full annual impact of the rate adjustment in the Test Year. The associated rate base items (*i.e*., plant, depreciation reserve, and deferred income taxes) will be updated to reflect actual balances as of September 30, 2019, as well as the related book depreciation expense.

Q. How was the adjustment calculated?

A. This adjustment multiplies the average billing rate associated with the rate changes for the 2019 Storm Hardening revenue adjustment to the weather normalized Test Year sales for the period prior to its implementation date (*i.e.*, October 1, 2018 – March 31, 2019). The Storm Hardening rate adjustment went into effect on April 1, 2019 so adjustment is not needed from that month forward as the revenue will already be included in the Test Year operating revenue.

Q. What is the impact of this adjustment?

A. As a result of this adjustment, operating income will increase by $176,000.

Q. Are there any rate adjustments required after the Test Year?

A. No.

Q. With regards to storm hardening investments contained in the Company's 2017 and 2018 Storm Hardening filings is the Company requesting the Board make a prudence determination and finalize the base rate recovery for these expenditures previously approved on a provisional basis?

A. Yes. The Company is requesting a prudence determination for all Storm Hardening Program investments outlined in its 2017 and 2018 Storm Hardening filings that were not approved as prudent in the Board's 2017 Rate Order in Docket ER16050428, and to finalize the base rate recovery for these investments previously approved on a provisional basis. The prudence determination includes all investments in in the Storm Hardening filings including Harrington Park, Old Tappan, Closter, Oakland/Chuckanutt, and Smart Grid investments.

<u>Storm Reserve – Mobilization Costs</u>

Q. Are there additional clarifications associated with major storm reserve accounting that should be addressed in this proceeding?

A. Yes. As further addressed in testimony of the Company's Capital Budget and Plant Addition Panel, the final order issued in this base rate proceeding should confirm that the Company may charge to the major storm reserve costs above $50,000 per storm for mobilization efforts incurred to obtain the assistance of contractors and/or utility companies providing mutual assistance in reasonable anticipation that a storm will affect its electric operations to the degree meeting the criteria of a "major storm," but which ultimately does not do so.

Q. How will costs be allocated between Orange and Rockland and RECO for these mobilization efforts that do meet a "major storm" criteria?

A, The Company proposes that these costs be allocated based on an "EO" split developed based on the number of customers in each jurisdiction.

Q. How does the Company currently account for storm mobilization costs in those instances when a forecasted "major storm" does not materialize?

A. Storm mobilization costs would currently be expensed if a storm does not meet the established criteria for deferring these costs.

Q. What level of storm mobilization costs associated with the proposed $50,000 threshold did the Company incur in the Test Year?

A. The Company does not currently track mobilization costs for storm related events that do not meet deferral requirements. The Company is requesting the ability to defer storm mobilization costs in order to allow it to be more proactive and prepare sooner for storm events without being penalized by not being able to recover those costs, if a major storm does not occur. Early mobilization allows the Company to arrange for the resources it needs on hand, so it can respond to outages as early as possible.

"No-Fee" Debit/Credit Card Transactions

Q. Please describe the Company's current policy regarding residential customers that pay their electric and/or gas bills using a credit and/or debit card (collectively "CC/DC").

A. Under current practices, residential customers can pay their electric and/or gas bill using a CC/DC (accepted cards include MasterCard, Visa, and Discover). Though a CC/DC is accepted, residential customers are subject to a transaction fee of $3.95 each time they pay their bill using a CC/DC. These transaction fees are charged by the Company's third-party credit card processing vendor ("CC/DC Vendor"). The CC/DC Vendor assesses and collects these fees directly from customers. These fees have no impact on the Company's revenues.

Q. Is the Company proposing any changes to its policy regarding CC/DC payments for its residential customers?

A. Yes. The Company is proposing to shift to a "no-fee model" where the per-transaction CC/DC fee will be eliminated. Instead, the Company will incur the aggregate costs of processing CC/DC payments and will include the estimated annual transaction fees charged by the vendor into base rates charged to residential customers.

Q. Is the Company proposing this change for its commercial customers?

A. No. The transition to the "no-fee model" will only apply to residential customers. Commercial customers will continue to be charged a transaction fee of 2.6 percent of their bill if they pay their bill using a CC/DC.

Q. Please explain the Company's rationale for this proposal.

A. As the use of a CC/DC for transactions continues to increase, customers have an expectation that the Company will provide billing and payment options that are on par with those available when conducting other day-to-day transactions, like paying for groceries, a cell phone bill, or a medical bill. Though there are exceptions, it is becoming less common for companies to charge a separate fee for customers that use a CC/DC. Instead, any transaction costs associated with the use of a CC/DC are embedded in the price of the good/service and spread across all customers.

Over the past several years the Company has seen a 38 percent increase in residential customers that pay for their electric and/or gas bill by means of a CC/DC. In the five years ended December 31, 2018, RECO's residential customers paid $150,700 in credit card transaction fees; money that could have been used to pay for their utility bills. By moving to the no-fee model, the Company will become more aligned with other companies in increasing the convenience of using CC/DCs to conduct transactions. The Company also expects that the number of customers using the CC/DC payment option will increase as a result of this program, which will likely result in operational benefits such as a reduction in returned payments.

Q. When would the Company implement this change?

A. This change was approved by the NYPSC in Orange and Rockland's recently concluded electric base rate case. Both Orange and Rockland and RECO implemented this change effective April 1, 2019.

Q. What are the Company's estimated total annual O&M costs of transitioning to the no-fee model?

A. Based on preliminary discussions with the vendor, the Company estimates that the annual incremental O&M costs will be $60,000 in the Rate Year. These cost estimates are based on the standard projections for usage increase. The Company proposes that this amount be added as a "post-test year" adjustment to test year expense. This expense is known because it is a cost that Company does and will incur for processing the CC/DC transactions, and is measurable because it is based on vendor estimates.

Q. Does the Company propose any mechanism to address possible under- or over-collection of CC/DC fees?

A. Yes. The Company recognizes the estimated fees are based on projected acceptance rates and costs under the no-fee model. Therefore, the Company proposes to defer the difference between actual expense and the annual amount included in rates, until RECO's next base rate case, when the under- or over-collection will be refunded to or collected from customers.

Q. Does that conclude your direct testimony?

A. Yes, it does.

ROCKLAND ELECTRIC COMPANY
2019 Base Rate Case
Additional Employee Positions Requested

Accounting Panel
Attachment A

Base Rate Case No. 18-E-0067 **Weekly Positions**	Number	Hire Date	Annual Salary Per Employee	Salary Allocated To RECO O&M
Equipment Technicians	4	Sep 2019	100,173	78,824
Substation Operations Employees	2	May 2019	110,000	54,098
	6			132,922

Base Rate Case No. 18-E-0067 **Monthly Positions**	Number	Hire Date	Annual Salary Per Employee	Salary Allocated To RECO O&M
Underground Engineer	1	Apr 2019	94,500	6,971
SCADA Engineer	1	Jun 2019	108,000	5,311
DER Integration Financial Analyst	1	Jun 2019	90,000	22,131
Technical Programmers	1	Jun 2019	7,700	1,327
Technical Programmers	1	Sep 2019	7,700	1,327
New Business Service Engineer	1	Jun 2019	120,000	20,676
Information Technology Planning	1	Apr 2019	8,960	2,203
Corporate Communications Network Operations Support	2	Apr 2019	6,545	3,219
	9			63,165

Orange & Rockland Utilities, Inc.
2019 Annual Team Incentive Program (ATIP)
Goals Narrative

The ATIP goals for 2019 include a Customer Service Performance ("CSP") goal, an Earnings goal, an Operating Budget goal and a Capital Budget goal. The 2019 ATIP weightings will be: CSP 50%, Earnings 20%; O&M Budget 25%; and Capital Projects 5%. The CSP goal includes 20 distinct customer service goals, some of which require meeting multiple indices to satisfy the specific CSP goal. Each of the four ATIP goals is assigned a percent weighting, the sum of which equals 100%. A description of each of the ATIP goals is as follows:

CUSTOMER SERVICE PERFORMANCE – Weighted at 50%

The 2019 Customer Service Performance (CSP) component (Schedule A), weighted at 50%, includes 20 goals. Due to the fact the ATIP goals is administered at the O&R system level, the CSP goals are established on a system wide basis for electric and gas services, while also establishing service performance goals that apply to both electric and gas services and incorporate customer experience, safety, environmental and operational excellence. Although there a few gas specific ATIP goals, most of the goals relate to electric service and all goals motivate employees to provide cost-conscious, safe, environmentally efficient and customer-focused service to all O&R system customers.

Achievement of 16 out of the 20 goals will result in a payout of 100%, with various payout percentages available for varying number of goals achieved, ranging from 85% for achieving 13 goals to 120% for achieving all 20 goals. No payout is available if the Company achieves 12 goals or less.

The 20 customer service performance goals for 2019 are as follows:

1. Employee and Public Safety

1. **Injury/Illness Incidence Rate – Target ≤ 1.00**

   Achieve a Total Case Incident Rate of ("TCIR") of less than or equal to 1.00

2. **Significant High Hazard Injuries – Target = 0**

   Achieve a goal of zero.

   Significant High Hazard Injuries are injuries that arise from electrical or gas systems including electrical shocks, burns, exposure to asphyxiants; equipment/material impacts, or falls from heights greater than four feet, and require hospitalization for medical treatment exclusive of observation/diagnostic procedures.

3. **Motor Vehicle Collisions – Target ≤ 38**

Orange & Rockland Utilities, Inc.
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Goals Narrative

The goal is to experience less than or equal to 38 recordable motor vehicle collisions.

4. **Operating Activity Errors – Target ≤ 20**

   The goal is to experience less than or equal to 20 operating errors. n. There are three categories of operating errors – Operational Activity Errors, Work Performance Errors and Design/Process Management Errors.

5. **Damage Prevention – Target = Total Overall Damage Rate ≤ 2.20**

   The goal is to experience less than or equal to a 2.20 which is measured by the total number of damages per 1,000 One-Call tickets.

2. **<u>Environment and Sustainability</u>**

6. **Reduce Customer Emissions – Energy Efficiency – Target ≥ 43,400 MWh**

   Utilizing a portfolio of energy efficiency programs which include the Residential Efficient Products program, Small Business Direct Install (SBDI), Commercial /Industrial Existing Buildings Program (C&I), Behavioral Analytics, Upstream Lighting and Appliance, Midstream Lighting and Software Data Analytics, Customer Energy Services will strive to reduce customer electric consumption by 43,400 MWh in 2019. This reduction in MWhs equates to 23,860 tons of carbon emissions, 18.7 tons of NOx, and 21.7 tons of Sox (greenhouse gas).

7. **Reduce Customer Emissions – Gas Energy Efficiency – Target ≥ 26,860 Dth**

   Utilizing a portfolio of energy efficiency programs which include the Residential/ Commercial HVAC Midstream Program and the Residential Behavioral Program, Customer Energy Services will strive to reduce customer gas consumption by 26,860 DTh in 2019. This reduction in DTh equates to 1,571 tons of carbon emissions and is equivalent to taking 334 cars off the road.

8. **Written Notice of Violations – Target = 0**

   This goal is measured when a written violation, resulting in a monetary fine (>$1,000), issued by a state or federal environmental regulatory agency (i.e. NYDEC, EPA, NJDEP, etc.) is paid.

9. **Gas Leak Inventory (monthly average) – Target ≤ 40 and meet the two NYPSC Gas Leak Inventory performance metrics attached**

   The twelve-month average monthly inventory is calculated by summing, at year-end, the total leak backlog (Type 1, 2A, 2 and 3 as defined in PSC code) at the

Orange & Rockland Utilities, Inc.
2019 Annual Team Incentive Program (ATIP)
Goals Narrative

end of each month and dividing by 12. The year-end average monthly inventory cannot exceed 40.

10. Solar Connections – Two targets listed below – must achieve both

The target areas measure performance for solar projects that are processed in 2019 for residential and small commercial applications (less than 50kW) or Coordinated Electrical System Interconnection Reviews (CESIR) performed for any projects beginning in 2019. Successful performance would be based upon achieving and/or exceeding performance in both areas. Performance will be tracked monthly but the KPI performance will be measured on year-end results.

- Complete initial application screening within 10 business days of submittal **≥ 92%** of the time for residential and commercial customer application for installation of 50kW and less; and

CESIR studies up to 2 MW to be completed within 60 business days from the date of submission **≥ 80%** of the time. The detailed engineering study timeline is measured after payment and technical documentation from the customer is received for projects beginning in 2019. The results of the CESIR yield the financial and operational requirement to interconnect a system to O&R's grid.

3. <u>Operational Excellence</u>

11. Outage Frequency - SAIFI – Target ≤ 1.20

The annual Company-wide interruption rate cannot exceed 1.20 (excluding storms.

The System Average Interruption Index (SAIFI) represents the average number of times that a customer is affected by an outage during the year. It is calculated by dividing the total number of service interruptions experienced by customers during the year by the total number of customers served during the year.

12. Outage Duration – CAIDI – Target ≤ 115.5

The Company-wide average outage duration per incident cannot exceed 115.5 minutes (excluding major storms). .

The Customer Average Interruption Duration Index (CAIDI) is calculated by dividing the sum of all customer minutes of interruption for the year by the total number of customer interruptions.

13. Gas Made Safe Time – Target = Made safe ≥ 73% of the time within 75 minutes and meet all three NYPSC Gas Emergency Response performance metrics attached

Orange & Rockland Utilities, Inc.
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Goals Narrative

The goal is to make safe all leaks that meet the leak definition greater than or equal to 73% of the time within 75 minutes. The Made Safe goal was developed to measure the duration of time it takes to alleviate risk to the public. The goal measures from the time the odor call is received until a mechanic takes positive action to make the condition safe.

14. Cyber Security – Target = 0

The goal is no cyber intrusions or loss of data in high value networks and no violations of North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) Standards, or Personally Identifiable Information (PII), or Personal Health Information (PHI) regulations or laws.

15. Physical Security – Target = 0

The goal is no unauthorized intrusions of critical areas at critical locations. An unauthorized intrusion is a breach of the physical security measures by non-authorized personnel. Critical areas include the control room floor of the Energy Control Center (ECC), the Alternate Control Center, and locked buildings within the Pearl River Gate Station.

4. <u>Customer Experience</u>

16. Customer Service Appointments Kept – Target ≥ 95%

The goal measures how well we meet customers' expectations when we have scheduled an appointment with them. For the purposes of this goal, the appointments to be measured include, by department:

- Customer Meter Operations – Special meter reads, shared meter investigations, high bill meter tests/high bill investigation; and
- Gas Department – Shared meter investigations, high bill meter tests/high bill investigation, meter relocation; and
- Overhead Line Department – Drop services.

17. New Business Electric Services Energized ≤ 7 days – Target ≥ 94%

The goal is to improve the customer experience by managing timely installations of electric services from construction complete/site ready state to energization of services. Complete inspections, prepare and issue service/meter orders and complete energization of ≥ 94% of electric service requests/installations (excluding specialized meters, i.e. CT/PT metering and multiple meter sets and required customer requested appointment dates) within 7-business days following receipt of Fire Underwriters Inspection Certificate and a completed application from the Customer.

18. **First Call Resolution – Target ≥ 84%**

    The goal is to respond to a customer's question or concern, satisfactorily on the first call in ≥ 84% of the time. This indicator measures the percentage of customer calls handled by agents only and resolved on the initial contact.

19. **Customer Service Performance Incentive Mechanism – Target = meet all three NYPSC Customer Service performance metrics attached**

    This goal aligns a Customer Experience component of the CSP with the Customer Service Performance Incentive Mechanisms (CSPIM) from the Company's New York Rate Cases. The CSPIM establishes threshold performance levels for designated aspects of customer service. All three CSPIM performance metrics must be achieved to meet this goal.

20. **Storm Scorecard – Target ≥ 90**

    Performance on the 2019 O&R Storm Scorecard goal is based on achieving an average score of 90 points or higher for all category 2 and greater storms that occur in 2019.

Earnings Goal -- Weighted at 25%

The Earnings goal is based on the consolidated earnings of O&R and all subsidiaries. The target is equal to the approved earnings budget and achievement at the budget level would result in a payout at 100%. The Earnings goal employs a sliding scale, with a maximum payout of 120% for performance of $6.5 million over budget, to a 0% payout for performance of $8.1 million under budget.

Operating Budget Goal – Weighted at 25%

The Operating Budget goal is based on the Company's consolidated operating budget. The measurement of this goal excludes the budgeted expenses for all amortizations and reconciliations, and demand side management costs. The target for 2019 is equal to the 2019 budget, and achievement at the budget level would result in a payout at 100%. The Operating Budget goal employs a sliding scale, with a maximum payout of 120% for performance of $2.7 million under budget to a 0% payout for performance of $13.5 million over budget.

Orange & Rockland Utilities, Inc.
2019 Annual Team Incentive Program (ATIP)
Goals Narrative

Capital Budget Goal – Weighted at 5%

The 2019 capital projects component, weighted at 5%, includes 6 capital projects. Each capital project will have two goals; one for completion of the capital project on schedule; and the second for completion of the capital project on budget.

Achievement of 10 goals will result in a payout of 100%, with various payout percentages available for varying number of goals achieved, ranging from 80% payout for 8 goals to 120% for achieving all 12 goals. No payout is available for the capital projects component if less than 8 of the 12 goals are achieved.

The Company's capital investment program enables the implementation of several key electric and gas projects that provide substantial capacity and reliability enhancements to the system, as well as, improved customer service and satisfaction.

The 6 Capital Projects are as follows:

1. **Gas Main Replacement** – Replace at least 22 miles of leak prone pipe. Completed by December 31, 2019 and not to exceed the budgeted amount of $27.8M.

2. **Line 47 Underground Transmission** – Obtain all required permits, perform civil design, bid process and procurement, construction and installation of the 3.2 mile underground civil system required for the new Line 47 from Harings Corner to Closter substations, except for the two bores located adjunct to the reservoir. The work described above shall be completed by December 31, 2019 and project spending is not to exceed the budgeted amount of $12.8M.

3. **Smart Meters (AMI)** – Completion of the following four Smart Meter milestones:
   i. Complete the deployment of Smart Meters in New Jersey (99% of non-opt out meters eligible to be installed by Meter Installation vendor) by September 30, 2019;
   ii. Complete the deployment of Smart Meters in Rockland County (99% of non-opt out meters eligible to be installed by Meter Installation vendor) by December 31, 2019;

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iii. Complete the AMI Communication Network (Access Points and Relays) in Sullivan County and Orange County by December 31, 2019; and
iv. Achieve at least 50,000 AMI meter/module installations in Orange County/Sullivan County by December 31, 2019.

This project work will not exceed the budgeted amount of $29.5M by more than 5%.

4. **Ramapo Bank Upgrade** – The project consists of the following tasks: Receive Bank 1300 and set in temporary location. Receive Bank 2300 and set on permanent concrete slab. Assemble, process and complete installation of Bank 2300. Bank 2300 will be energized by September 30, 2019. The cost for the project should not exceed $9.9M[1].

5. **Port Jervis Substation** – The project consists of the following tasks: Construction and energization of the Temporary Kolmar Transformer.

   The Port Jervis Substation must complete the procurement bid process, award a purchase order, and attain the mechanical shop drawing approval milestone for the two 40MVA transformers and the switchgear.

   Lastly to obtain all required permits, perform civil design, bid process and procurement of the civil construction contractor, offloading of the existing substation, and civil construction contractor mobilization by December 31, 2019. The cost for the project should not exceed $5.8M[1].

6. **Wyckoff Distribution Automation Enhancement** – The project will enhance the Distribution Automation for the Township of Wyckoff. The first phase of installation concentrated on installing SCADA control MOAB switching devices on all "open" distribution circuit tie points and several other key locations on both circuit (ckt: 39-1-13 and ckt: 39-8-13) to assist with restoration. Construction work includes SCADA commissioning. The work described above shall be completed by October 2019 and project spending will not exceed the budget amount of $425K.

[1] Costs for any environmental remediation required and/or any subsequent capital expenditures for additional project acceleration above the scope described above are excluded; and any costs associated to the banks storage.

ROCKLAND ELECTRIC COMPANY
DIRECT TESTIMONY OF
DEPRECIATION PANEL

I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q. Would each member of the Depreciation Panel (“Panel”) please state their name and business address?

A. Matthew Kahn and my business address is 4 Irving Place, New York, New York.

Ned W. Allis and my business address is 207 Senate Avenue, Camp Hill, Pennsylvania.

Q. Mr. Kahn, by whom are you employed and in what capacity?

A. I am employed by Consolidated Edison Company of New York, Inc. (“Con Edison”) as Section Manager of the Tax Department. I manage the functions related to book and tax depreciation for Con Edison and its regulated affiliates, including Rockland Electric Company (“RECO” or the “Company”). I also support the income tax compliance and accounting functions for Con Edison and its regulated affiliates.

Q. Mr. Kahn, please briefly outline your educational background and business experience.

A. I graduated from Bentley College (now Bentley University) in 2004 with an undergraduate degree in accounting, and completed a master’s degree in taxation at Bentley University in 2010. I have been employed by Con Edison since 2010. Prior to my employment at Con Edison, I worked in various roles within the accounting industry and in the field of taxation with PricewaterhouseCoopers, LLC, and subsequently as an analyst with American Tower Corporation. I am a member of the Society of Depreciation Professionals ("SDP").

Q. Mr. Allis, by whom are you employed and in what capacity?

A. I am employed by Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming"), where I am Vice President. I am responsible for conducting depreciation, valuation and original cost studies, determining service life and salvage estimates, conducting field reviews, presenting recommended depreciation rates to clients, and supporting such rates before state and federal regulatory agencies. I am also responsible for Gannett Fleming's proprietary depreciation software, training of depreciation staff, and the development of solutions for technical issues related to depreciation.

Q. Mr. Allis, please briefly outline your educational background and business experience.

A. I have a Bachelor of Science degree in Mathematics from Lafayette College in Easton, PA. I am a current member and past president of the SDP. I am certified as a depreciation expert by the SDP, which has established national standards for certification via an examination that I passed in September 2011. I was re-certified as a depreciation professional in March 2017.

I became employed by Gannett Fleming in October 2006 as an Analyst. My duties included assembling basic data required for depreciation studies, conducting statistical analyses of service life and net salvage data, calculating annual and accrued depreciation, and assisting in preparing reports and testimony setting forth and defending the results of the studies. In March 2013, I was promoted to the position of Supervisor, Depreciation Studies. In March 2017, I was promoted to Project Manager, Depreciation and Technical Development. In January 2019, I was promoted to my current position of Vice President.

Q. Have any members of the Panel previously provided testimony before the New Jersey Board of Public Utilities ("Board")?

A. **(Kahn)** Yes. I have previously submitted testimony on behalf of the Company in BPU Docket No. ER16050428. I have also testified before the New York State Public Service Commission.

(Allis) Yes. I have previously submitted testimony on behalf of the Company in BPU Docket No. ER16050428 and have submitted testimony on behalf of the Atlantic City Electric Company in BPU Docket Nos. ER18060638 and ER18080925. I have also testified before eight other regulatory commissions, including the Federal Energy Regulatory Commission.

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

A. The Panel's direct testimony:

- Presents the Depreciation Study performed by Gannett Fleming for the Company's electric plant;
- Presents annual depreciation accruals based on the Company's existing rates, as well as the proposed depreciation rates recommended by the Depreciation Study;
- Addresses the Company's net salvage recovery, including the Board's annual allowance for net salvage, as well as a true-up to that allowance; and
- Discusses the Company's recovery of unrecovered costs for legacy meters due to the implementation of its Advanced Metering Infrastructure ("AMI") Program.

Q. Is the Panel sponsoring any exhibits in this proceeding?

A. Yes, the Panel is sponsoring the following three exhibits, all of which were prepared under the Panel's supervision and direction:

- Exhibit ___ (P-7, Schedule 1) entitled: "Proposed Depreciation Rate Changes for Electric Plant at December 31, 2017;"
- Exhibit ___ (P-7, Schedule 2) entitled: "Computation of the Annual Net Salvage Allowance at December 31, 2017;" and
- Exhibit ___ (P-7, Schedule 3) entitled: "2017 Depreciation Study" (*i.e.*, the Depreciation Study).

Q. Are there any subjects addressed in the Panel's direct testimony that are not, and should not be construed to be, sponsored by all members of the Panel?

A. Yes, there are four: the annual net salvage allowance, the unallocated reserve, the true-up to the annual net salvage allowance, and the recovery of legacy meter costs. While an annual net salvage allowance was calculated in the Depreciation Study, the Company calculated the net salvage allowance, unallocated reserve and true-up for the net salvage allowance for the test year in this proceeding. Accordingly, for the purposes of the initial filing in this proceeding, the Company has considered these subjects and the recovery of legacy meter costs to be within the sole purview of Company management as ratemaking approaches rather than Depreciation Study topics. Mr. Allis and Gannett Fleming Valuation and Rate Consultants, LLC have no responsibility for the Company’s decisions on these subjects whether in testimony, discovery responses or pleadings of any nature and express no view on them. Mr. Allis and Gannett Fleming Valuation and Rate Consultants, LLC reserve the right to present or join in testimony on any of these subjects at a later stage in these proceedings if proposals are made by Board Staff and/or other parties that would produce results materially different from the Company’s filing.

Q. What effect will all of your proposed changes have on the Company’s annual depreciation expense?

A. As summarized on Exhibit P-7, Schedule 1, based on existing rates, the Company’s annual depreciation expense relating to the Company’s total electric and general plant, excluding the unallocated accounts, is approximately $7.1 million. This amount will increase by approximately $0.6 million based on the Company’s proposed rates, and result in an annual depreciation expense of approximately $7.7 million.

II. RECOMMENDED DEPRECIATION RATES AND DEPRECIATION STUDY

Q. Please define the concept of depreciation.

A. Depreciation refers to the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the Company is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, and action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and the requirements of public authorities.

Q. In preparing the recommended depreciation rates based on the Depreciation Study, did the Panel follow generally accepted practices in the field of depreciation?

A. Yes.

Q. Are the methods and procedures used for the recommended depreciation rates and accruals consistent with RECO’s past practices?

A. Yes, with the exception of the technique used in the calculation of depreciation rates. The Depreciation

Study proposes to use the remaining life technique instead of the whole life technique used in previous RECO depreciation studies. The remaining life technique is widely used in the industry and is used by many other New Jersey utilities, including New Jersey’s three other electric distribution utilities. For example, the remaining life technique was adopted by the Board for Jersey Central Power & Light Company in BPU Docket No. ER12111052 and was used in recent depreciation studies for Public Service Electric and Gas Company and Atlantic City Electric Company.

For the calculation of annual depreciation rates and accruals, the Panel employed both the straight line method and the broad group average service life procedure.

Q. Please describe the presentation of the Depreciation Study in your exhibits.

A. The Panel’s recommended depreciation rates are provided in Exhibit P-7, Schedule 1. Exhibit P-7, Schedule 2, provides the calculated net salvage allowance.

The Depreciation Study supporting the recommended survivor curves is presented in Exhibit P-7, Schedule 3. This study is presented in six parts. Part I, Introduction, presents the scope and basis for the

Depreciation Study. Parts II through V include descriptions of the methods and procedures used for the estimation of survivor curves, the calculation of the net salvage allowance, and the calculation of annual depreciation and the theoretical reserve. Part VI, Results of Study, presents a description of the results and a summary of the estimated survivor curves. Parts VII and VIII present graphs and tables that relate to the service life analyses and the detailed depreciation calculations.

Q. How did you determine the recommended annual depreciation accrual rates?

A. First, we developed estimates of the average service life and retirement dispersion curves for each depreciable group - that is, each plant account or subaccount identified as having similar characteristics. We then calculated the annual depreciation accrual rates using the applicable survivor curves. Finally, the Company calculated the net salvage allowance based on RECO’s experienced net salvage.

Q. Please describe the first phase of the estimation of depreciation for RECO, in which you estimated the average service life and dispersion curve for each plant account or subaccount.

A. The Depreciation Study consisted of compiling historical data from records related to the Company’s plant; analyzing these data to obtain historical trends of survivor characteristics; obtaining supplementary information from management and operating personnel concerning practices and plans as they relate to plant operations; and interpreting these data and information along with the service lives used by other utility companies to form judgments of service lives applicable to the Company’s plant and equipment.

Q. What historical data did you analyze for the purpose of estimating service lives?

A. We analyzed accounting entries that record plant asset transactions during the period 1952 through 2016. The transactions included additions, retirements, transfers and the related balances.

Q. What method did you use to analyze these data?

A. We used the retirement rate method. This is the most appropriate method when retirement data covering a long period of time is available because this method determines the average rates of retirement actually experienced by the Company during the period of time covered by the Depreciation Study. It is also the method used in past depreciation studies performed by

RECO and is the predominate approach used in depreciation studies across the country for public utilities and other companies when aged data is available.

Q. Please describe how you used the retirement rate method to analyze the Company's service life data.

A. We used the retirement rate method to analyze each different property group, generally a particular plant account, in the Depreciation Study. For each property group, we used the retirement rate method to form a life table which, when plotted, shows an original survivor curve for that property group. Each original survivor curve represents the average survivor pattern experienced by the vintage groups during the experience band studied. The survivor patterns do not necessarily describe the life characteristics of the property group. Therefore, interpretation of the original survivor curves is required in order to estimate future average service lives properly. Standard survivor curves, such as the Iowa-type survivor curves are used to perform these interpretations.

Q. What is an “Iowa-type survivor curve” and how can such curves be used to estimate the average service life characteristics for each property group?

A. Iowa-type curves are a widely-used group of survivor curves that contain the range of survivor characteristics usually experienced by utilities and other industrial companies. The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observing and classifying the ages at which various types of property used by utilities and other industrial companies had been retired.

Iowa-type curves are used to smooth and extrapolate original survivor curves determined by the retirement rate method. The Iowa-type curves can be used to describe the forecasted rates of retirement based on the observed rates of retirement and the outlook for future retirements.

The estimated survivor curve designations for each depreciable property group indicate the average service life, the family within the Iowa system to which the property group belongs, and the relative height of the mode.[1] For example, the Iowa 50-R1.5 indicates an average service life of 50 years; a

[1] The mode describes the height of the frequency curve, which is a plotting of the percentage of assets retired in a given year. The lower the mode, the wider the dispersion pattern for the survivor curve (*i.e.*, a smaller percentage of retirements will occur at ages closer to the average service life). The higher the mode, the more narrow the dispersion pattern for the survivor curve (*i.e.*, a larger percentage of retirements will occur at ages closer to the average service life).

right-moded, or R, type curve (the mode occurs after average life for right-moded curves); and a relatively low height, 1.5, for the mode (possible modes for R type curves range from 1 to 5).

We more fully describe survivor curves in Part II of Exhibit P-7, Schedule 3.

Q. What is the h-system of survivor curves?

A. The h-system of survivor curves was developed in 1947 by Bradford Kimball of the New York State Department of Public Service. Similar to the Iowa curves, the h-curves are labeled in accordance with the relative height of the modes of the associated retirement frequency curves. While the h-system of curves had been used in the past by New York utilities, there are currently very few utilities in the country that still use h-curves. Indeed, h-curves are, to our knowledge, not used anywhere outside of the state of New York. Further, the h-curves tend to have long "tails," meaning that these curves forecast that a portion of property will survive much longer than the average service life of a given depreciable group. These types of life characteristics are not common for most types of utility property.

Q. What type of survivor curves have you proposed to use in the Depreciation Study?

A. For the Depreciation Study, we recommend the use of Iowa type survivor curves. This represents a change from the h-type curves used in the Company’s previous study. However, the Iowa curves are, to our knowledge, used in every U.S. jurisdiction, including New Jersey. In addition, the Iowa curves typically provide a more reasonable retirement dispersion pattern for most types of utility assets. For these reasons, it is appropriate to use Iowa type survivor curves for RECO.

Q. Please provide an example of how you estimated the annual depreciation accrual rate for a particular plant account.

A. We will use electric Plant Account 362, Station Equipment, as an example because it is one of the largest depreciable accounts. We used the retirement rate method to analyze the survivor characteristics of this property group. We compiled aged plant accounting data from 1952 through 2016 and and we analyzed each account over a period that best represents the overall service life of the property in the account. For most accounts, we used the full period of time (1952-2016). For certain accounts, we used shorter periods to adjust for anomalies and other account-specific factors. The life table for the 1952-2016 experience band is presented on pages VII-43 through VII-45 of

Exhibit P-7, Schedule 3. The life table displays the retirement and surviving ratios of the aged plant data exposed to retirement by age interval. For example, page VII-43 shows $357,761 retired at age 0.5 years, with $225,085,951 having been exposed to retirement. Consequently, the retirement ratio is 0.0016 ($357,761 / $225,085,951) and the survivor ratio is 0.9984 (1 – 0.0016). We calculated the percent surviving for the next age interval (*i.e.*, age 1.5) of 99.84 percent by multiplying the percent surviving of 100.00 percent at age 0.5 by the survivor ratio at age 0.5 of 0.9984. We plotted this life table, or original survivor curve, along with the estimated smooth survivor curve, the 45-S0, on page VII-42.

The calculation of the annual depreciation related to original cost of Account 362, Station Equipment, at December 31, 2017, is presented on pages VIII-15 and VIII-16 of Exhibit P-7, Schedule 3. We based the calculation on the 45-S0 survivor curve, the attained age, and the allocated book reserve. The tabulation sets forth the installation year, the original cost, calculated accrued depreciation, allocated book reserve, future accruals, remaining life, and annual accrual. These totals are brought forward to Table 1 on page VI-4. In addition, on Table 2 we calculated the net salvage allowance as of December 31, 2017 based on the normalized expense method for this account.

III. UNALLOCATED RESERVE AND NET SALVAGE ALLOWANCE

Q. You have referred to the unallocated depreciation reserve. Please explain what it represents and why you have excluded it from your analysis.

A. In BPU Docket No. ER02100724, the Board ordered the Company to allocate to customers all net salvage costs (*i.e.*, gross salvage proceeds less removal costs spent) already collected from customers but not yet spent to physically remove assets. At the same time, in lieu of recovering ongoing net salvage costs through the annual depreciation rate, the Board established an annual allowance to be collected through base rates. This annual allowance is to be computed by averaging the Company's annual actual expenditures for net salvage costs. In addition, the Board allows the Company in subsequent rate filings to true-up differences between the allowance provided for in rates and the actual level of net salvage costs incurred since the allowance was last trued up in the Company's previous base rate case (*i.e.*, BPU Docket No. ER16050428). In order to track these costs properly, it was necessary for the Company to establish a number of accounts.

Q. Please discuss the unallocated accounts individually.

A. The Company currently has four unallocated depreciation reserve accounts and they are summarized on Exhibit P-7, Schedule 1. As of December 31, 2018, the first unallocated depreciation reserve account (account 399100) held a remaining credit balance totaling $8.6 million for an excess reserve variation originally established in February 2017 at $9.8 million.

Q. Please describe the second unallocated depreciation reserve account.

A. The second unallocated depreciation reserve account (account 399030) holds the Company’s current reserve for net salvage, the balance of which represents costs either over- or under-collected from customers since the last time the Company’s rates were reset by the Board. For instance, if the level of net salvage costs actually spent exceeds the amount being collected via the net salvage allowance, the account balance will represent an amount the Company has under-collected from customers. Conversely, if the allowance in rates exceeds the actual amount the Company has spent for net salvage costs, the Company has over-collected from customers.

Q. Please describe the third and fourth unallocated depreciation reserve accounts.

A. Similar to what I just described for account 399030, accounts 399080 and 399090 represent the true-up amounts regarding under-recoveries of net salvage costs from the Company's 2015 and 2017 base rate proceedings.

Q. What is the plan for recovery of these balances?

A. As provided for in Exhibit P-2, Schedule 18, the annual amortizations in accounts 399080 and 399090 are set to expire. The Company proposes that the remaining balance of $8.1 million in account 399100 be amortized over approximately 12.4 years, in an annual amount of $0.7 million beginning in the Rate Year.

Q. Please discuss the annual net salvage allowance.

A. The Board moved away from the traditional approach of recovering net salvage through depreciation rates in BPU Docket No. ER02100724. Instead, the Board approved an allowance for net salvage based on an average of historical costs. That is, the Board's current approach does not recover future net salvage prospectively over an asset’s service life. Instead, net salvage costs are recovered after they are incurred. Consistent with the Board’s approach for net salvage used in RECO’s last base rate case, the Company has computed a new allowance based on a three-year average of net salvage amounts spent by the Company for the calendar year period 2016 through 2018.

Q. Have you prepared an exhibit that summarizes your proposed revised net salvage allowance?

A. Yes. The Company has prepared an exhibit entitled ROCKLAND ELECTRIC COMPANY, COMPUTATION OF THE ANNUAL NET SALVAGE ALLOWANCE (Exhibit P-7, Schedule 2). This exhibit summarizes the annual net salvage charged per books and computes the average amount for the period. It then compares that average to what is currently allowed in rates and computes the incremental increase or decrease in the allowance. This exhibit indicates the need to increase the existing net salvage allowance from $1,024,404 to $1,784,000 annually, or an incremental increase in the annual allowance of approximately $760,000. Such an increase will allow the Company to recover net salvage costs in accordance with the average of historical costs method.

Q. Did the Accounting Panel make an adjustment to your net salvage allowance calculation?

A. Yes. Based on the Accounting Panel's review of projects that incurred negative salvage in 2017, they indicated that there were several major substation related projects that were retired. The type of work that was done at these facilities is not expected to be recurring in the next three years and there are no similar retirements in the Company's Capital Budget. As a result, the Accounting Panel "normalized" the historic average annual expenditures for purposes of setting the rate allowance in this case. The adjustment is discussed in more detail in the Accounting Panel's direct testimony.

Q. Do you agree with the Accounting Panel's adjustment?

A. Yes. We believe it is important to calculate the allowance for negative net salvage on a consistent basis in each base rate case. Negative net salvage is difficult to forecast; major storms and other unforeseen events can significantly impact the level of annual spending. However, given the non-recurring nature of the substations retired in 2017, we believe it is appropriate in this instance to normalize the level of spending as reflected by the Accounting Panel in their adjustment.

Q. Is there a required true-up for differences between the allowance provided for in rates and the actual level of net salvage costs incurred since the true-up in the Company's last base rate proceeding?

A. Yes. As set forth in Exhibit P-2, Schedule 19, the Company incurred an additional amount of net salvage costs above the Board-approved rate allowance.

Q. Please summarize the Company's proposed true-up.

A. Over the course of the 33 months through September 30, 2019 (*i.e.*, the end of the test year), the Company will have charged approximately $5.3 million of net salvage expense, while the allowances during that period provided $2.8 million. Consistent with prior practice and Board approvals, the Company proposes to amortize and recover this shortfall of $2.5 million over three years, which is an annual amount of approximately $800,000.

IV. UNRECOVERED LEGACY METER COSTS DUE TO THE IMPLEMENTATION OF AMI

Q. Please discuss the Company’s proposal to recover its investment in “legacy” meters due to its implementation of the AMI Program.

A. As discussed by Company witness Scerbo, AMI is a technology for improving efficiencies related to meter reading and providing other system and customer benefits including storm recovery related benefits. These initiatives involve installing electric AMI meters across RECO’s service territory, necessitating the removal of the older, “legacy” technology (*i.e.*, electro-mechanical and solid state meters) before they are fully depreciated. According to the current schedule, the Company expects to complete the installation of AMI meters by the end of June, 2019, as discussed in the direct testimony of Mr. Scerbo. Depreciation accruals on the book costs of the legacy meters cease upon their retirement even though they have not been fully depreciated. As a result, a separate cost recovery vehicle for the undepreciated basis is required.

Q. What is the level of unrecovered book cost associated with the legacy meters?

A. Upon completion of the installation of AMI meters, the Company currently projects that there will be $5.2 million of unrecovered book costs associated with the legacy meters.

Q. What is the Company's proposal for addressing the remaining unrecovered investment in legacy meters upon completion of the implementation of AMI?

A. The Company proposes that the net remaining unrecovered costs would be deferred to a regulatory asset. The Company would amortize the remaining unrecovered costs of the legacy meters over a 15-year period. The Company believes a shorter period can be justified for recovery of these legacy meter costs that it has already incurred in the provision of service to its customers. However, a 15-year period will serve to moderate the rate impact to customers for recovery of the Company's remaining undepreciated investment in legacy meters

Q. How has the Company determined the estimated unrecovered cost of those legacy meters?

A. As of December 31, 2018, the net book value for electric meters that will be replaced during the implementation of the AMI program was approximately $5.8 million. As noted, the Company projects that upon completion of the AMI implementation plan, the remaining unrecovered costs will be approximately $5.2 million for electric meters. The reduction from the current net book value to the projected unrecovered costs is the result of continuing to recover the meter costs that remain in service at current depreciation rates.

Q. What is the annual level of expense associated with a 15-year period for recovery of the unrecovered meter costs?

A. As provided for in Exhibit P-2, Schedule 20, a 15-year straight-line recovery would result in an annual depreciation expense of approximately $350,000.

Q. Does that conclude your direct testimony at this time?

A. Yes, it does.

ROCKLAND ELECTRIC COMPANY
DIRECT TESTIMONY OF
CAPITAL BUDGET AND PLANT ADDITION PANEL

NJBPU Docket No. _____________

Q. Would the members of the Capital Budget and Plant Addition Panel ("Panel") please state their names and business addresses?

A. **(Regan)** Angelo M. Regan, 390 West Route 59, Spring Valley, New York 10977.

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

(Coffey) John F. Coffey, 390 West Route 59, Spring Valley, New York, 10977.

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

A. **(Regan)** I am employed by Orange and Rockland Utilities, Inc. ("Orange and Rockland"), the corporate parent of Rockland Electric Company ("Rockland Electric," "RECO," or the "Company"), as Director of Electrical Engineering.

(Banker) I am employed by Orange and Rockland as Chief Engineer of Distribution Engineering.

(Coffey) I am employed by Orange and Rockland as Chief Engineer of Transmission and Substation Engineering.

Q. Please briefly describe your educational and business experience.

A. **(Regan)** I received a Bachelor of Science degree in Electrical Engineering in 1985, and a Master of Science degree in Industrial Engineering Management Science in 1987, both from Fairleigh Dickinson University, in Teaneck, New Jersey. I am a licensed Professional Engineer in the State of New York. I have worked for Orange and Rockland for over 31 years as an overhead and underground Systems Engineer, as Manager of the Distribution Engineering Department, and then as Chief Distribution Engineer, prior to assuming my present position and responsibilities as Director of Electrical Engineering.

(Banker) 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 licensed Professional Engineer in the State of New York. I joined Orange and Rockland in 1990 and have held positions for Orange and Rockland as an underground Distribution and Transmission Engineer, as Divisional Field Engineer for the Electrical Operations Department, and my present position, which I assumed in 2005, as Chief Engineer of Distribution Engineering. This position oversees the planning, engineering and design of underground transmission and distribution projects included in the capital improvement budget.

(Coffey) I received a Bachelor of Science degree in Electrical Engineering from Manhattan College in 1988. I am a licensed Professional Engineer in the State of New York. 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. I have over 30 years of electrical engineering experience and have worked for Orange and Rockland for over 29 years. I have served in my current position since 2010. This position oversees the planning, engineering and design of transmission and substation projects included in the capital improvement budget.

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

A. **(Regan)** Yes, I have testified in various proceedings before the Board, including RECO's 2009 base rate case, Docket No. ER09080668.

(Banker) Yes. I previously submitted testimony in the Company's last base rate case, Docket No. ER13111135, regarding plant additions and capital budget and in the Company's storm hardening proceeding, Docket No. ER14030250 ("RECO Storm Hardening Proceeding'), as part of the Storm Hardening Panel.

(Coffey) Yes. I previously submitted testimony in the Company's last base rate case, Docket No. ER16050428, as part of the Electric Infrastructure Grid Panel and in other cases.

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

A. The purpose of our testimony is to present and support RECO's electric distribution plant additions and capital budget included in this base rate case. The Panel will also discuss routine Electric Blankets (*i.e.*, projects necessary to maintain RECO's distribution system). We will discuss the status of the Company's Storm Hardening Program. In addition, the Panel will provide the basis for certain updated unit charges set forth in the Electric Rate Panel's testimony. Finally, the Panel will discuss RECO's Danger Tree Program and a proposed modification to the Company's major storm cost reserve.

<u>Plant Additions and Capital Budget</u>

Q. Are you familiar with planned plant additions and the construction budget for RECO?

A. Yes. This information is set forth in Exhibit P-3, Schedule 12, which was prepared under our direction.

Q. Please discuss the plant additions set forth in Exhibit P-3, Schedule 12.

A. Exhibit P-3, Schedule 12, shows the major plant additions that RECO proposes for inclusion in rate base in this proceeding, along with their in-service dates and the quantified expenditures for each project (including associated Allowance for Funds Used

During Construction ("AFUDC") and excluding the Cost of Removal). These plant additions fall into the following categories: (1) those already underway that have been completed or are scheduled to be completed during the test year ending September 30, 2019 ("Test Year"), (2) those that are scheduled to be completed Post-Test Year (through March 2020), and (3) various blanket programs. Each of these projects will be discussed in more detail later in this testimony.

Q. Does RECO have a robust electric delivery system planning process that effectively evaluates its system growth and capacity requirements?

A. Yes.

Q. Please describe the Company's electric delivery system planning process.

A. Each year, the Company performs detailed planning studies that determine electric load growth and assess the performance of the electric delivery system throughout a future forecast period with respect to its electric distribution design standards. The Company's electric planning design standards provide guidance in prioritizing various electrical infrastructure projects for the RECO electric delivery system. The design standards are developed to balance the costs of infrastructure investment versus the benefit of mitigating the risk of significant outage events, as measured by both the amount of load or number of customers impacted and the anticipated duration of the outage. These standards are a key to the capital planning process, both short- and long-term, as they provide a process by which future risk mitigation investments are identified and prioritized. The electric design standards primarily incorporate a risk assessment methodology that provides criteria to assess if the electric facilities are, or will be, operating outside of acceptable tolerances for equipment loading, operating parameters and customer exposure. The Company completes a ten-year assessment as part of its annual planning process.

Q. Please describe in more detail RECO's forecasting and risk assessment processes.

A. The annual planning process commences with forecasting the overall system load including loads for all of the distribution lines and distribution transformer banks. Also included are forecasts for each individual substation transformer bank, and all of the distribution circuit loads for the upcoming summer peak. The impact of photovoltaics ("PV"), distributed generation ("DG") or distributed energy resources ("DER") and other demand-side management ("DSM") measures, such as energy efficiency programs and voluntary or program-structured load reductions, are also included in forecasted growth rates. Substation transformer banks and substations are grouped into specific load regions based on logical switching capabilities between adjacent stations and banks. Mathematical regression models leverage historical peak loads for each region, along with other relevant variables, to forecast weather-normalized loads through a future forecast period for each region. The Company then utilizes a process to apportion the regional growth and expected demands through the forecast period to each substation transformer bank and distribution circuit within the region. Any known block loads or transfers in the region are then accounted for and applied to the affected infrastructure accordingly.

The Company uses all of the projected loads determined through its forecasting process to perform operating reviews on each of its major assets. These reviews cover transmission lines and banks down through their distribution circuits, for both normal operating conditions and for the failure or removal of those components through a detailed contingency analysis. The results of the contingency analysis are then evaluated against RECO's design standards to assess if the electric facilities are, or will be, operating outside of acceptable tolerances. If any of the assets do not meet their respective design standards at some point during the forecast period, a solution is determined, scheduled and prioritized as part of the Company capital budget development process.

Q. Once the high-level solution is identified by the initial output of the planning process, is that the end of the process?

A. No. As part of its annual planning processes, the Company periodically evaluates the need for, and appropriate timing to implement, its identified capital projects. The Company initially investigates if alternative and less costly traditional infrastructure investments can substantially defer, reprioritize, or even eliminate more costly major capital infrastructure investments. Some of these traditional solutions include constructing lower cost distribution projects to defer upgrades or new builds, using new technologies and distribution automation for improved asset utilization, reprioritizing and accelerating the construction of lower cost distribution and substation investments, or simply deferring the planned construction period and accepting the associated risk for projects with less exposure in order to accelerate construction of higher-risk projects. This is part of RECO's planning process and system review, and the Company evaluated all of these alternative traditional infrastructure solutions to determine where it could appropriately defer higher cost major capital investments as Exhibit P-3, Schedule 12, was developed.

Q. Once an optimal solution is determined, does RECO have a formalized process to prioritize its projects?

A. Yes. The Company has a two-step process for prioritizing its major electric capital infrastructure projects. The first is completed within the system planning process, and then these projects are prioritized against other Company projects through a corporate-wide prioritization methodology.

Q. Please explain both of these prioritization processes.

A. After all methods of alternate solutions are exhausted, the final project solutions are initially prioritized by Electrical Engineering. Multiple drivers determine the priority of a project and each driver has several possible components that contribute a weighted value. The key drivers include load, existing condition towards satisfying design standards, condition of equipment, relationship with respect to sequential project needs, reliability, customer needs, and construction window availability. Other drivers, such as operating conditions, safety, system losses and voltage improvements that provide additional benefits are considered. The total weight sets the priority of the project relative to other projects. Once the proposed portfolio of corporate projects is selected based on technical and economic screening, the portfolio is analyzed using the Company's strategic alignment prioritization methodology and process. The projects are ranked relative to each other based on their impact on:

- Improve Public and Employee Safety;
- Reduce Cost to Customers;
- Provide Reliable Service;
- Improve Customer Experience;

- Enhance External Relationships;
- Reduce and Manage Risk;
- Strengthen and Develop Employees;
- Strengthen Company Processes; and
- Sustain Environmental Excellence.

The final project portfolio is then selected by the respective department managers and directors, and ultimately approved by the Company's executive management team.

Q. Please describe the process and procedures used to monitor and evaluate individual project milestones and cost objectives against actual and expected outcomes and benefits.

A. The Company's Project Controls Group tracks project performance on all large capital projects. The Project Controls Group is part of the Company's Project Management Department and is responsible for the development and tracking of project schedules, estimates and contract documentation for all large capital projects. This group is comprised of schedulers, estimators and contract documentation specialists. The Project Controls Group and individual project teams utilize standardized project schedules to track schedule performance and milestone achievement. The Company's cost analysts and project managers use Oracle Business Intelligence software to track actual costs and expenditure details.

Q. What projects are included in the Major Plant Additions set forth in Exhibit P-3, Schedule 12?

A. The plant additions shown in Exhibit P-3, Schedule 12, predominantly reflect electric distribution system improvement projects that provide upgrades to existing plant or add new distribution circuitry. The majority of these projects are line extension and reconductoring projects. These projects are aligned with the substation system improvements that the Company has identified which support increased substation capacity and improved reliability of the Company's electric delivery system. The plant additions also include planned distribution and substation projects and upgrades.

Test Year Major Capital Projects (through September 2019)

Q. Please describe the major electric capital projects (over $250,000) that have been or are projected to be completed and booked to plant in-service through September 30, 2019.

A. A description of these projects follows, including a tdiscussion of additional information such as the project background, project history, screening for alternatives, and project benefits.

Reserve at Franklin Lakes Phase 1

Project Description – This new business project is to install underground distribution facilities for a new subdivision in Franklin Lakes. The project includes over 9,000 feet of trench, 26,000 feet of 15kV cables, thirty-four (34) single phase transformers, and six (6) padmounted switches. The underground system will be installed as a joint trench among electric, telephone, and gas. The estimated cost for this project is $350,000.

Project Background – The Reserve at Franklin Lakes, is a one-hundred forty eight (148) unit subdivision comprised of one (1) clubhouse, one (1) pump house, twenty eight (28) single family homes, fifty five (55) apartments and sixty-five (65) town-homes. The site is located on Ewing Ave in Franklin Lakes.

Alternative Solution Screening – The job was designed by the Company's Line Technical Services and Distribution Engineering departments in the most cost-effective manner to serve the customers' requirements. The electric facilities are required to be underground for this new subdivision.

Project Benefits – This project will install electric facilities required to serve a new subdivision located in Franklin Lakes with 148 customers. These new facilities will have the ability to serve all current and future electric needs for this new development.

Closter Breaker Replacements

Project Description – This project calls for the replacement of the three Closter 69kV oil circuit breakers with new SF6 gas insulated circuit breakers ("GCBs"), also known as a "puffer" breaker, along with the associated control cables. In addition, associated relay protection and the existing RTU/SCADA system will be upgraded as well, to bring the station to current technology. The breakers and associated relay protection were replaced by December 2018 but there are still remaining RTU/SCADA upgrades that are currently scheduled to be replaced in May 2019. The estimated cost for this project is $1,545,000.

Project Background – The three breakers at Closter are oil insulated circuit breakers that were manufactured in 1960 and 1970 and have been in service since that time. As the breakers have reached their useful life of 59 and 49 years, it is appropriate to replace the breakers to minimize and avoid any future risks to the system should the breakers fail.

Alternative Solution Screening – The project is driven by the age, condition and obsolescence of the assets and there are no other viable solutions except for replacement.

Project Benefits – Proactively replacing breakers before failure will reduce risk to the system and the potential for future customer outages. In addition, GCBs minimize failures and this project will remove approximately 4,000 gallons of oil from the system. This will improve safety for Company personnel working within the substation environment and limit the Company's environmental liability from potential spills and leaks. In addition, as the Company is preparing to expand the existing Closter substation, these upgrades to the existing station would improve the overall reliability of the substation and help allow the transition of new technology proposed for the expansion.

Ringwood Breaker 983/984-78-2

Project Description – The Ringwood Substation currently has two remaining oil circuit breakers in service. This project calls for the replacement of the Ringwood 983-78-2 and 984-78-2 oil circuit breakers with new SF6 GCBs, along with the associated control cables. The estimated cost for this project is $601,000.

Project Background – The Ringwood Substation currently has five 69kV breakers - four line breakers and one bus tie breaker. Three of the five breakers were replaced to gas circuit breakers in the early 1990's and in 2016. The remaining two oil filled breakers were installed in 1954 and 1975. Breaker 983-78-2 is a 69kV Westinghouse G0-4B oil filled breaker manufactured in 1954 and has been in service for approximately 64 years. Breaker 984-78-2 is a 69kV ITE 69KSB oil filled breaker manufactured in 1975 and has been in service for approximately 43 years. The remaining two oil filled breakers have exceeded their service life and it is appropriate that the Company replace these breakers with gas filled circuit breakers. Breaker 983-78-2 is experiencing issues with the compressor system.

Alternative Solution Screening – The project is driven by the age, condition and obsolescence of the assets and there are no other viable solutions except for replacement.

Project Benefits – Proactively replacing the breakers before failure will reduce risk to the system and the potential for future customer outages. In addition, GCBs minimize failures and this project will remove approximately 1,800 gallons of oil from the system. This will improve safety for Company personnel working within the substation environment and limit the Company's environmental liability from potential spills and leaks.

Sweetwater Lane, Ringwood

Project Description – This project is to rebuild the underground distribution facilities in the Bald Eagle Park subdivision in Ringwood that will cover the following streets: Sweetwater Lane, Fieldstone Drive, Old Forge Road, and Copper Hill Park. The total trench footage is approximately 6,700 feet and all existing cable will be replaced with #2 Al 15kV cables. Cable fault indicators and lightning arrestors will also be installed. The estimated cost for this project is $809,000.

Project Background – The Company has reviewed the outages and cable no flow sections that have affected customers in the Bald Eagle Park subdivision and determined the cable has reached the end of life and needs to be replaced. This rebuild project will remove five previously faulted cable sections, an existing faulted section and address a safety issue associated with the corroding neutral on the cable. This rebuild will remove 1/0 AAC, CN cables which were installed in 1976.

Alternative Solution Screening – One alternative solution for this project was to use silicone fluid injection into the cable to re-establish the insulation levels of the existing cables. This was tried in 2005 but was unsuccessful due to conductor blockage. With the recent developments of corroded cable neutrals, the only viable solution would be a total cable rebuild project.

Project Benefits – This project will replace the cable system for the 88 customers that are served from the Bald Eagle Park subdivision and will reduce the likelihood of future cable faults from occurring. This rebuild will improve system reliability and ultimately reduce O&M expenditures related to underground operations response to system faults.

Additional Projects That Will Be Completed Post-Test Year (Through March 2020)

Q. Has the Company proposed to include other major capital projects (over $250,000) to be completed following the end of the Test Year in rate base.

A. Yes. RECO has proposed to include several projects that fall into this category.

Q. Please explain why the Company proposes these projects for inclusion in rate base in this case.

A. These projects represent major rate base additions that the Company forecasts to be in service within six months of the end of the Test Year (*i.e.*, by March 31, 2020). These projects are known, because the Company is committed to making these capital additions and has commenced project development, and they are measurable because their costs can be substantiated with reliable data. The Company has quantified the forecasted costs through an analysis of recent spending for material, equipment and labor costs that have been experienced on similar projects that are in progress or recently have been completed by the Company. RECO is planning to purchase and receive materials for these projects by the end of the Test Year.

Further, these projects are scheduled to be in service and used in the provision of electric service to customers during the time when new rates are in effect. As discussed above, these are major projects that are critical for maintaining the level of service reliability that the Company's customers require.

Wyckoff Automation/Resiliency

Project Description – This project has been designed to enhance the distribution automation in the Wyckoff area by the installation of eight SCADA control MOAB switching units. These devices will allow faults to be isolated quickly and customers to be restored before any crews arrive on location. This will greatly improve the restoration time for customers who have experienced a power loss. In addition, by isolating faults quicker, safety is greatly improved as well. The estimated cost for this project is $416,000.

Project Background - After the storm outages experienced by the Township during the March 2018 winter storms, the Company committed to the officials in Wyckoff, NJ and to the BPU, that the Company would storm harden the circuits feeding the Wyckoff area by expanding the installation of Smart Grid devices.

Alternative Solution Screening –There were no other viable alternatives for this project.

Project Benefits - The existing overhead distribution system contained manual operated switching devices, this project through enhance automation will have a positive impact on the service reliability and restoration of the distribution system associated with service outages during storms. The project will be critical during storm conditions as multiple paths of the overhead system can be damage at a time.

Allendale Breaker T588-239 Replacement

Project Description – This project calls for the replacement of the Allendale Breaker T588-239 oil circuit breaker with a new SF6 GCB, along with the associated control cables. The estimated cost for this project is $350,000.

Project Background – The breaker at Allendale is a G.E oil insulated circuit breaker that was manufactured in 1978 and has been in service since that time. The air tank currently has a leak. To get a new tank would cost about $10,000. As the breaker has reached its useful life of 41 years, it is appropriate to replace the breaker to minimize and avoid any future risks to the system should the breaker fail.

Alternative Solution Screening – The project is driven by the age, condition and obsolescence of the assets and there are no other viable solutions except for replacement.

Project Benefits – Proactively replacing the identified problematic breaker before failure will reduce risk to the system and the potential for future customer outages. In addition, GCBs minimize failures and this project will remove approximately 2,400 gallons of oil from the system. This will improve safety for Company personnel working within the substation environment and limit the Company's environmental liability from potential spills and leaks.

<u>Old Tappan – Howard Drive</u>

Project Description – This project will establish a main line overhead distribution tie between Harings circuit 30-4-13 and Closter circuit 28-3-13 on Howard Drive in Old Tappan. This is the third and final project to complete the tie between Old Tappan Road and Blanchard, the previous two projects were completed in 2017 (reconductor Old Tappan Rd and Russell Ave). This project requires the installation of three (3) additional Motor Operated Air Break switches ("MOABs") to provide enhance switching via SCADA control. The project was designed for the installation of 2800 feet of new overhead Hendrix Spacer Cable construction. To limit the impact of the tree trimming associated with this project, the Company employed a three-phase spacer cable assembly. Older, smaller, and lower class poles that do not meet current construction standards will be replaced as part of this project and all open wire secondary will be replaced with more tree resistant 4/0 triplex wire. The estimated cost for this project is $470,000.

Project Background – Currently 471 customers are served via a radial overhead feed from circuit 30-4-13 on Old Tappan Road (east of Central Avenue), some of the critical customers include Old Tappan Municipal Building, large shopping center, Fire and Police Station, Department of Public Works and two (2) area schools. In addition, there are another 138 customers on a radial feed from circuit 28-3-13 on Blanche Ave, in Harrington Park. The new project will fill in the gap between Old Tappan Road and Blanche Ave and will facilitate restoration and enhance reliability to the area by providing a new circuit contingency.

Alternative Solution Screening – The Company considered the installation of an open wire system but the cost to complete the required tree trimming and the amount of customer impacts were too severe. This alternative was not selected as it did not provide the reliability improvements of the proposed project.

Project Benefits – In total, the project will improve restoration for 609 customers on a radial feed and will benefit both the 30-4-13 and 28-3-13 feeders. The new distribution tie will provide switchable back up for customers in Old Tappan and Harrington Park areas. The project will be critical during storm conditions as multiple paths of the overhead system can be damage at a time.

Montvale – Main Street 4kV Conversion

Project Description – This project is designed to convert Main Street, Phyllis Drive and Ladik Place in Montvale from 4.16 kV to 13.2 kV served from an existing step bank located on Main Street in Montvale. To improve overall reliability, approximately 20 poles will be replaced and 1300 feet of #4 copper primary conductor will be replaced as part of the project. All open wire secondary will be replaced with 4/0 triplex. The estimated cost for this project is $325,000.

Project Background - Currently seventy (70) customers are served from 1-250kva step bank and have experienced multiple outages in the past as of a result of a step-down bank failure, motor vehicle and multiple tree contacts. Many of the poles and transformers are over 50 years old; converting this area will significantly increase restoration times and improve overall reliability to the area.

Alternative Solution Screening – The Company also considered keeping the area at 4.16kV and replacing the #4 copper primary conductors. This alternative was not selected as it did not provide the reliability and voltage improvements of the proposed area.

Project Benefits - Removal of the step bank will improve service reliability and voltage to 70 customers along Main Street, Phyllis Drive, Erie Street and Ladik Place. Replacing this conductor will reduce the probability of a failure due to tree or animal contacts. Total system losses will be reduced with the upgraded of the conductor and the elimination of core losses associated with the step-down transformer.

Franklin Lakes – Old Mill Road Wyckoff Support

Project Description **–** This project will establish a new mainline distribution tie from Old Mill Road to West Main Street in Wyckoff. To execute this project will require the installation of 900 feet of three-phase overhead distribution on Old Mill Road, extending a double circuit Hendrix construction for approximately 450 feet, and relocating 450 feet of overhead conductor to refeed Merck Medco. The project also calls for the installation of a three-phase regulator, capacitor bank, and two MOAB switches. The estimated cost for this project is $550,000.

Project Background - The Township of Wyckoff is served from the tail-end of five (5) long distribution circuits supplied by two different substations: Allendale and Franklin Lakes. These two substations are responsible for serving approximately 4,550 Wyckoff customers. Due to the length of the existing distribution circuits (39-1-13 & 39-8-13) and loading, the circuits have a high exposure that result in poor performance during storm conditions, as a result of vegetation contact and/or equipment failure. When an event occurs on circuits from the Allendale substation, there is limited capacity during peak periods to restore all the customers in Wyckoff as a result of loading. In Franklin Lakes there is one distribution circuit (ckt: 35-9-13) that is operating at 120 amps (20% of its design capacity) that can provide capacity relief and an alternate feed to serve a portion of the Wyckoff load. The feeder is located on Old Mill Road and this new project will create a new distribution tie from Old Mill Road to West Main Street in Wyckoff.

Alternative Solution Screening – Using an open wire primary design verse spacer cable design was elevated as a possible alternative. The spacer Hendrix conductor will be able to withstand both tree and miscellaneous branch contacts, eliminate temporary faults, and provide enhance lightning protection (via a shield wire). The Company selected a spacer design as it will enhance overall resiliency and will have a positive impact on the reliability for Wyckoff area customers.

Project Benefits - The project will improve restoration for 1021 customers and will benefit both the 39-1-13 and 39-8-13 feeders. The new distribution tie will provide switchable back up for customers in Wyckoff.

Oakland – Long Hill Road Hendrix

Project Description – This project requires replacement of 2700 feet of three phase open wire conductor with 477 AAC Hendrix constructions between Martha Place and Breakneck Road in Oakland, NJ. In addition to the reconductor project, this project supports enhanced distribution automation with the installation one additional MOAB switch. The estimated cost for this project is $350,000.

Project Background - The project will improve service reliability, address aging poles, and conductors. This project will also replace multiple automatic sleeves indicative of past damage and repairs. This project will resolve a known problem area, as a result of a heavy tree canopy, approximately 1600 feet on length. These are mature trees and would be very difficult to remove. As a result of the tree canopy, this general area experiences outages throughout the year and during storm events.

Alternative Solution Screening – The Company considered an open wire system but due to the tree condition a spacer design was identified which will be able to withstand both tree and miscellaneous branch contacts, eliminate temporary faults, and provide enhance lightning protection (via a shield wire).

Project Benefits - The project will enhance overall resiliency for over 550 customers and will have a positive impact on the reliability for Oakland area customers. This includes several commercial establishments that serve downtown Oakland area including a large shopping center.

Orangeburg Road UG Circuit 30-7-13

Project Description – This underground project will take advantage of a larger construction project (Line 47) that will be constructed on the same path as Orangeburg Road, in Old Tappan and provide storm hardening benefits. Combining both major capital projects using the same trench will reduce overall construction cost on Orangeburg Road between the Harings Corner Substation and Old Tappan Road in Old Tappan. This project will eliminate a double circuit overhead distribution path on Orangeburg Road for approximately 1,100 feet before they separate and feed their respective load pockets in Old Tappan and Norwood. The underground system will be installed in concrete encased conduits with manholes utilizing 3-750kcm copper cables. The estimated cost for this project is $410,000.

Project Background - This project will address reliability issues associated at the head end of the circuit (Ckt: 30-7-13) near the Haring Corner Substation. This portion of the circuit is served from a double circuit overhead construction, the project will convert a portion of circuit to an express underground distribution feeder starting at the Haring Corner Substation and rising on Orangeburg Road (400 feet west of Old Tappan Road).

Alternative Solution Screening – The existing system consists of a double circuit overhead construction and the only viable solution to increase reliability would be to install one of the circuits underground. No other solution was identified for this area.

Project Benefits - This selective undergrounding project will enhance overall resiliency and will have a positive impact on the reliability for Old Tappan and Norwood area customers. This is a project that will provide storm hardening benefits to 1600 customers. The cost of this project is greatly reduced as it will be installed in conjunction with a larger transmission project that is currently being construction in the area.

Allendale 39-1 & 39-6 Reroute

Project Description –   This underground project will address a number of issues including swapping two distribution circuits (39-1-13 & 39-6-13) to alternate substation transformer banks. This project will construct a new 2,400 feet dual underground distribution feeder between the Allendale Substation and new station exit riser poles to be located on Franklin Turnpike and East Crescent Avenue. The underground system will be installed in concrete encased conduits with manholes utilizing 3-750kcm copper cables. The estimated cost for this project is $1,650,000.

Project Background - The Allendale Substation is a two bank (Bk 139 & 239) station with 35MVA 69/13.2kV transformers that serve eight 13.2kV distribution circuits and 9200 customers. Distribution contingency analysis identified several issues associated with Allendale Substation, including bank contingency, station bank loading (Bk 239), distribution circuit ties with other substations, and a storm hardening project to eliminate a double circuit condition on two streets (Heights Road and Crescent Place). In addition, the project will solve some causes associated with the performance of the circuit (39-8-13).

Alternative Solution Screening – Due to the geographic area, rerouting circuit 39-1-13 and 39-6-13 was the only option. In addition to bank loading and bank contingency, circuit 39-1-13 and 39-8-13 which are currently served from the same substation bank (Bk 239), run parallel to each other along Brookside Ave to serve the majority of the load (approximately 3,000 customers) in Wyckoff will now be served from alternate banks.

Project Benefits - The project will resolve a number of issues such as substation bank loading, eliminating two separate double circuit configurations and enhance our overall switching capabilities both in the distribution system and in the event of station bank failure.

<u>Blanche Road UG Circuit 28-3-13</u>

Project Description – This underground project will be constructed to take the opportunity of a larger construction project (Line 47) that will be constructed on the same path as Blanche Avenue, in Norwood and provide storm hardening benefits. Combining both major capital projects using the same trench will reduce overall construction cost on Blanche Avenue between the Closter Substation and Tappan Road in Norwood. The scope of this project is to eliminate a double circuit overhead distribution path on Blanche Avenue for approximately 4,500 feet before they separate and feed their respective load pockets. The underground system will be installed in concrete encased conduits with manholes utilizing 3-750kcm copper cables. The estimated cost for this project is $1,590,000.

Project Background - This project will address service reliability issues associated at the head end of the circuits 28-3-13 & 28-8-13 near the Closter Substation. This portion of the circuits are served from a double circuit overhead construction, the project will convert a portion of one of the circuits to an express underground distribution feeder starting at the Closter Substation and rising on Blanche Avenue. When an event occurs as a result of a Motor Vehicle Accident ("MVA"), vegetation contact or equipment failure on this portion of Blanche Ave both circuits are in jeopardy of being off-load loaded that affects 2,600 customers.

Alternative Solution Screening – The existing system consists of a double circuit overhead construction along a single route and the only viable solution to increase reliability would be to install one of the circuits underground. No other solution was identified for this area.

Project Benefits - This selective undergrounding project will enhance overall resiliency and will have a positive impact on the reliability for Closter and Norwood area customers. This is a project that will provide storm hardening benefits to 2,600 customers. The cost of this project is greatly reduced as it will be installed in conjunction with a larger transmission project that is currently being construction in the area.

<u>Harrington Park – Hackensack Ave Hendrix</u>

Project Description – This project will address defective and substandard poles both on Hackensack Ave and various streets located in Harrington Park, NJ. This project will include replacement and installation of larger standoff brackets to accommodate 25kV Hendrix spacer brackets to provide added clearance between phases and messenger, installation of anti-sway brackets, enhance pole grounds associated with bonding of spacer messenger, replace open wire secondary (#4 or #6cu.), replace pole guys, sub-standard transformers, and defective poles with Class 2 poles. The estimated cost for this project is $300,000.

Project Background - The area was originally constructed in the early 1970's with a "spacer" construction designed with three-phase 477 AAC conductor, small porcelain spreader spacer brackets (with rubber ties), short standoff brackets, and substandard forty-foot (class 3) poles. This project will address service reliability, obsolescence equipment due to age/end of life, and re-enforce for storm resiliency. During a previous storm (Feb 2019), the area experienced an extended outage due to multiple pole damage and the work involved to make repairs.

Alternative Solution Screening – Replacing the existing obsolescence spacer system with an updated open wire system was considered but due to the tree condition an updated spacer design was identified which will be able to withstand both tree and miscellaneous branch contacts, eliminate temporary faults, and provide enhance lightning protection (via a shield wire).

Project Benefits - This is a reliability project to replace aging infrastructure to enhance overall resiliency for over 290 customers on Hackensack Ave with multiple sides streets fed directly from our main-line on Lafayette Avenue.

Q. Should the Board consider an alternative method for timely reflection of the post-test year projects in rates if it determines not to reflect them in rates at the conclusion of this base rate case?

A. Yes. Preliminarily, we emphasize that the costs of these known and measurable projects should be included in rates at the conclusion of this base rate proceeding for all of the reasons discussed above. For a utility the size of RECO, it is imperative that its major investments be reflected in rates in a timely manner and recovered during the period when those investments are being used to provide service to customers, and these investments will be in service within six months following the end of the Test Year. It is our understanding that this base case would be concluded in February 2020 or earlier, if the Board concludes it within the typical nine-month period from the filing date during which filed rates are suspended. If that schedule is followed, and if the Board determines not to allow inclusion of these costs in rate base at the conclusion of this case (which it should not do, for all the reasons above), the Board should provide for the immediate commencement of a Phase II proceeding directly before the Board that is limited to the review of the final costs of these projects and the adjustment of rate base and rates to reflect the recovery of these costs. Such a Phase II proceeding should be promptly commenced and expeditiously processed so that Phase II rates may go into effect on or about June 30, 2020, since all the projects will have already been placed into service by that date. The Board has previously considered RECO's Darlington Substation project in such a Phase II proceeding in Docket ER02080614 and Docket ER02100724.

Multi-Year Capital Projects (2019 – 2020)

Q. Do any of the Company's proposed capital projects span more than one year?

A. Yes. Electric Blankets that cover projects in the field necessary to properly maintain RECO's distribution system. Expenditures for these projects are captured in six blanket categories:

i. Distribution Reliability Blanket;
ii. Electric Distribution Blankets;
iii. Electric Meter and Transformer Blankets;
iv. Smart Grid Automation and Resiliency Program
v. U/G Circuit Relocation and Rebuild Blanket; and
vi. All Other Electric Blankets.

Each of these is described further below.

Q. What is included in each of the Electric Blankets categories set forth in Exhibit P-3, Schedule 12?

A. The electric blankets include a variety of work, including all materials and labor, which must be performed so that the Company can continue to provide reliable service. Blankets are an accounting convention, long accepted by the Board and its Staff, whereby, for the sake of convenience, the costs of certain labor and equipment are grouped together. There are blankets for work to be concluded within the test year and within the six months following the test year included in Exhibit P-3, Schedule 12. These include:

a. Distribution Reliability Blanket – This blanket is for the replacement of defective poles and incremental lightning protection for enhanced circuit reliability.

b. Electric Distribution Blanket – This blanket covers project work associated with new business installations, as well as work on the overhead distribution system.

c. Electric Meter and Transformer Blankets – This blanket is for the purchase of utility meters and transformers.

d. Smart Grid Automation and Resiliency Program -– This blanket is focused on installing and upgrading field devices with command and control schemes which will result in improved storm resiliency and system reliability. The philosophy is a three-tiered approach: circuit optimization, field automation and centralized automation control.

- Circuit Optimization - Design an efficient system through the use of Smart Capacitors, Phase balancing and Power Quality monitoring (sensors).
- Field Automation - Automatic fault isolation via recloser auto loop schemes which automatically reduce customer outages.
- Centralized Automation Control - Monitoring and Control from the Distribution Control Center (DCC)

The Company's forecasted plan for January 2019 through March 2020 includes the installation of mid-point reclosers and additional SCADA operable switches (MOABs).

e. U/G Circuit Relocation and Rebuild Blanket - This blanket covers project work associated with the replacement of underground distribution cable systems that have been subjected to repeat failures. These projects will replace aged underground cable systems with new cable to increase service reliability in underground subdivisions.

f. All Other Electric Blankets – This blanket is for the purchase of small tools for operations, substation transformer metering upgrades, substation paving and drainage improvements, load research meter purchases, smart grid device purchases and the operations distribution capacitor installation program.

As is apparent from Exhibit P-3, Schedule 12, expenditures for these blankets will occur throughout the test year, and during the six-month post-test year period where capital expenditures may be included in revenue requirements. These costs are major, are known (they continue Test Year expenditures), and are measurable. Indeed, the forecasted blanket costs are based on recent costs for the same or similar material, equipment and labor as has been experienced on similar blanket projects that are in progress or recently have been completed by the Company. The post-test year portion of the Electric Blanket should be included in rates in this proceeding. However, if the Board determines not to allow inclusion of these costs in rate base at the conclusion of this case (which it should not do, for all the reasons above), the Board should address them in the Phase II proceeding discussed above.

Unit Charges Applicable to Extension of Lines and Facilities

Q. Are, you familiar with the Electric Rate Panel's testimony regarding the proposed updates to the unit charges applicable to extensions of lines and facilities to reflect current costs in General Information Section No. 17?

A. Yes.

Q. What is the purpose of your testimony regarding these changes?

A. We will be providing the basis for the updated unit charges.

Q. Please explain.

A. The unit charges are used to develop a design and cost estimate for the construction of the Company's electric distribution and service facilities. These unit charges have a labor and/or material component. The labor component for a specific work unit is a target that represents the average reasonable expected time to perform a specific task or work unit that has been established from field time studies of line crews performing these tasks. The material component represents the average unit price for the current materials used for construction of the electric distribution and service facilities as specified by the Company's Electric Distribution Standards.

Q. What is the primary cause for the changes in the unit charges?

A. The changes in the charges are primarily related to changes to the labor rates and material costs that have been updated for wage increases and inflation over the past several years (*i.e.*, since 2017, when the rates were last updated). In addition, revisions to the regulations (N.J.A.C. 14:3-8.2) that defined the costs allowed in the development of the unit charges have disallowed for the recovery through these charges for supervision and general clerical functions. As a result, we have removed these costs from the unit charges.

Q. How are these rates applied?

A. The Electric Rate Panel covers the application of these unit costs in their direct testimony.

<u>Storm Hardening Program</u>

Q. Please describe the Company's Board-approved Storm Hardening Program ("SHP").

A. The Board approved RECO's SHP in its Order dated January 28, 2016 in BPU Docket Nos. AX13030197 and ER14030250 ("Storm Hardening Order"). In that Order, the Board adopted a Stipulation ("SHP Stipulation") that explicitly authorizes the Company to implement a SHP consisting of the capital investment level of up to $15,724,100 to be recovered through a stipulated SHP Revenue Adjustment Mechanism which includes periodic base rate roll-ins, on a provisional basis. The Storm Hardening Order noted that the Company anticipated making storm hardening capital investments over a three-year (36-month) period, beginning on the effective date of the Storm Hardening Order (*i.e.*, February 6, 2016). Specifically, RECO would invest in the following incremental storm hardening and system resiliency subprograms with initial levels up to the following amounts to be recovered through the SHP Revenue Adjustment Mechanism: (a) $5,089,900 for Selective Undergrounding (*i.e.*, the West Milford project); (b) $2,334,200 for Overhead System Construction Projects; (c) $300,000 for Substation Flood Mitigation (*i.e.*, the Muscle Wall System); and (d) $8,000,000 for Distribution Automation/Smart Grid Expansion.

Q. Has the SHP concluded, and what was the final cost of the SHP?

A. Yes, by its terms the SHP has concluded. The final cost of the SHP capital investment recovered through the SHP Revenue Adjustment Mechanism, including SHP capital investments approved in the Company's last electric base rate case (BPU Docket No. ER16050428) ("2017 Base Rate Order ") was $14,469,100. See Attachment A. Notwithstanding the conclusion of the SHP, the Company is continuing to make certain capital investments (i.e. distribution automation/smart grid) though the Test Year as part of its base operations, as discussed below, to be recovered through base rates.

Q. Did the Board reserve the right to review the prudency of these SHP investments?

A. Yes. As noted in the Storm Hardening Order (p. 5), the Board will review the prudence of specific SHP investments in the next base rate case that is filed by the Company after those investments are placed into service. As discussed below, the Board approved the prudency of several of the Company's SHP investments in the 2017 Base Rate Order such that they need not be reviewed, and a prudency determination is not required in this case.

Q. Please discuss the status of the above-listed four storm hardening and system resiliency subprograms.

A. The status of these subprograms and the projects in these subprograms is set forth below.

Selective Undergrounding

The Selective Undergrounding sub-program consists of a single project located in West Milford, New Jersey, which the Company completed and placed in service as of December 31, 2016. The total project costs were rolled into the Company's electric rate base during its last electric base rate case pursuant to the Board's 2017 Base Rate Order.

Accordingly, in this proceeding, the Company is not seeking a prudence determination regarding its investment in this specific SHP investment.

Overhead System Construction Projects

Under the Overhead System Construction subprogram, the Company has undertaken the following five enhanced overhead system construction projects:

<u>Harrington Park-Harriet Ave (Schraalenburgh to Bogert Mill)</u>

This project involves the replacement of approximately 5,500 feet of 3/0 ACC overhead primary with higher capacity mainline spacer cable construction (477 conductors) and the installation of Class 2, 50-foot poles. Project construction has been completed and the system placed in service on October 27, 2017. The total project costs were $781,900. As set forth in the SHP Stipulation, the projected capital costs for this project were $830,000. These costs were included for recovery in electric base rates on a provisional basis pursuant to the Board's Decision and Order Approving Stipulation, issued March 26, 2018 I/M/O the Petition of Rockland Electric Company for Approval of Electric Base Rate Adjustments Pursuant to Storm Hardening Program (BPU Docket No. ER17101066) ("2018 SHP Order"). In light of the final cost of this project, combined with the fact that it has been placed in service and is fully operational and is being used to provide service to customers, the Board should find this project prudent and finalize the inclusion of its costs in rate base and base rates.

<u>Old Tappan-Old Tappan Road Reconductor</u>

The project involves replacement of approximately 2,500 feet of 3/0 ACC overhead primary with mainline 477 conductors, several additional switches, and the installation of

Class 2, 50-foot poles. Project construction has been completed and the system placed in service on June 30, 2017. The total project costs were $102,500. As set forth in the SHP Stipulation, the projected capital costs for this project was $331,600. These costs were included for recovery in electric base rates pursuant to the 2018 SHP Order. In light of the final cost of this project, combined with the fact that it has been placed in service and is fully operational and is being used to provide service to customers, the Board should find this project prudent and finalize the inclusion of its costs in rate base and base rates.

<u>Closter-Cedar Lane (Tie to Schraalenburgh Road)</u>

This project involves the replacement of 500 feet of overhead primary with mainline spacer cable construction (477 conductors), installation of two additional automated switch points, and the installation of Class 2, 50-foot poles to establish a new, and additional distribution circuit tie (28-5-13 and 28-8-13). Project construction has been completed and the system placed in service on June 28, 2018. The total project costs were $153,800. As set forth in the SHP Stipulation, the projected capital costs for this project was $300,200. These costs were included for recovery in electric base rates on a provisional basis pursuant to the Board's Decision and Order Approving Stipulation, issued March 13, 2019 I/M/O the Petition of Rockland Electric Company for Approval of Electric Base Rate Adjustments Pursuant to Storm Hardening Program (BPU Docket No. ER18101114) ("2019 SHP Order"). In light of the final cost of this project, combined with the fact that it has been placed in service and is fully operational and is being used to provide service to customers, the Board should find this project prudent and finalize the inclusion of its costs in rate base and base rates.

Oakland-Chuckanutt Drive Tie

This project involves the replacement of approximately 1,800 feet of single-phase construction with new three phase construction (477 conductor), additional switches, and installation of Class 2, 50-foot poles to establish a new and additional distribution circuit tie (35-10-13 and 35-5-13). Project construction has been completed and the system placed in service on October 11, 2018. The total project costs were $513,200. As set forth in the SHP Stipulation, the projected capital costs for this project was $420,300. The projected capital costs were based on a high level engineering estimate and the final cost was based on the actual design for the project and actual construction costs. Further, the Board-approved SHP Stipulation (at ¶ 23) expressly provided that "The Parties recognize that it may be difficult to precisely budget each overhead project. Accordingly, the Parties agree that a process enabling the Company to make adjustments to overhead project budgets in response to real conditions is justified, so that investment may be reallocated among the five overhead projects as set forth in this paragraph with an Overhead System Construction Sub-Program Investment Cap of $2,234,200." As shown in Attachment A, the final costs of the Overhead System Construction Sub-Program were $2,003,500, which is below the Sub-Program Cap. The costs of the Oakland-Chuckanutt Drive Tie project were included for recovery in electric base rates on a provisional basis pursuant to the 2019 SHP Order. In light of the final cost of this project, combined with the fact that it has been placed in service and is fully operational and is being used to provide service to customers, the Board should find this project prudent and finalize the inclusion of its costs in rate base and base rates.

Wyckoff-Godwin Avenue Mainline

This project involves the replacement of approximately 2,600 feet of #2 ACSR overhead primary conductors with higher capacity mainline open wire construction (477 conductors) and the installation of Class 2, 50-foot poles. This project has been completed and was placed in service as of December 31, 2016. The total project costs were rolled into the Company's electric rate base during its last electric base rate case pursuant to the 2017 Base Rate Order. Accordingly, the Company is not seeking a prudence determination regarding its investment in this specific SHP investment.

Substation Flood Mitigation

This subprogram involves the Company's purchase of a Muscle Wall Flood and Containment Solution ("Muscle Wall") that it will store and pre-position as needed to divert flood water away from the Cresskill and Upper Saddle River substations. The Company purchased and received this equipment in 2016. The total project cost of $300,000 was approved for inclusion in the Company's electric rate base during its last electric base rate case pursuant to the 2017 Base Rate Order. Accordingly, the Company is not seeking a prudence determination regarding its investment in this specific SHP investment.

Distribution Automation/Smart Grid Expansion

As of December 31, 2018, RECO has installed 273 SCADA operable devices since receiving Board approval in the Company's Storm Hardening Proceeding to accelerate its automation plan. The devices installed include seven (7) auto-loops (16 new reclosers), ten (10) new mid-point reclosers, and 142 SCADA operable switches (MOABs). In addition, 105 devices were updated with remote control functionality. As set forth in the SHP Stipulation, the projected capital cost for this subprogram was $8,000,000. As set out in Attachment A, the spending on this subprogram through December 31, 2018, and recovered through the SHP Revenue Adjustment Mechanism (including capital investments approved in the 2017 Base Rate Orderwas $7,075,700. This project has been placed in service and is fully operational and is being used to provide service to customers. The Board should find this project prudent and finalize the inclusion of its costs in rate base and base rates.

Q. What are the Company's plans for Smart Grid going forward?

A. During the Test Year and beyond, the Company plans include the installation of mid-point reclosers and additional SCADA operable switches ((MOAB). The ultimate goal for distribution automation/smart grid is to have all applicable circuits in auto-loop configuration and to have SCADA operable switches (MOABs) installed at strategic locations such that the Control Center can isolate and restore outages remotely, reducing the affected segments to no more than 250 customers.

Danger Tree Program

Q. Please explain the Danger Tree Program

A. Orange and Rockland retained BioComplance to complete a study on the trees in the Orange and Rockland and Rockland Electric service territories titled "Utility Forest Condition Assessment of Orange and Rockland Utilities Service Territory". This study, noted the number of ash trees and that the Emerald Ash Borer has a nearly 100% mortality rate. There are approximately 17,000 ash trees in RECO's service territory. The average cost to remove an ash tree is approximately $700. As a result, the potential exposure to remove every ash tree in RECO's service territory could approach $12 million (i.e., 17,000 trees x $700 per tree). In addition to the Emerald Ash Borer issue, RECO will need to remove trees that have succumbed to the stress of overhang removal work. To initiate the Danger Tree program, the Company is requesting initial funding of $500,000 per year.

Major Storm Cost Reserve

Q. Does the Company's most recent base rate order include a storm cost reserve?

A. Yes. Consistent with prior RECO base rate orders, and subject to various terms and conditions, the 2017 Base Rate Order (at p. 5) provides for the Company to charge costs to the reserve. Specifically, storm costs for each individual storm qualify for deferred accounting if the storm caused electric disruption for 10% or more of customer in an operating area or if customers are without power for more than 24 hours and incremental costs incurred for each individual storm exceed $130,000, The Company proposes that the major storm cost reserve be continued, with one modification to the storm cost reserve.

Q. What modification to the major storm cost reserve does the Company propose?

A. As discussed in the Accounting Panel's direct testimony, the Company proposes that it be allowed to charge to the major storm cost reserve for costs the Company incurs to obtain the assistance of contractors and/or utility companies providing mutual assistance in reasonable anticipation that a Major Storm will affect its electric operations, but which ultimately does not do so, either at all or to the extent forecasted.

Q. Explain when this type of charge to the major storm cost reserve would apply.

A. In order to expedite restoration efforts when a Major Storm is forecast, the Company's Electric Emergency Response Plan may call for the pre-staging of contractors and/or mutual assistance crews, taking into consideration the forecasted regional weather impact and pre-determined minimum staffing requirements. However, weather forecasting is not an exact science, and storms that the Company reasonably expects to require contractors and mutual aid may turn out to be less severe than predicted, or not materialize at all. Because such contractor and mutual aid mobilization costs are reasonably incurred, the Company is proposing to charge the costs associated with pre-staging contractors and/or mutual assistance crews to the major storm cost reserve when these costs exceed $50,000 per event.

Q. Why is it an appropriate time to make this modification to the storm reserve?

A. The pre-staging of contractors and/or mutual assistance crews to expedite restoration efforts when a Major Storm is forecast, is consistent with the Board's Order and Staff's Report regarding storm preparedness and the March 2018 storms in BPU Docket No. EO18030255.

Q. Does this conclude your testimony?

A. Yes, it does.

Summary of Storm Hardening Program ("SHP")
(Thousands of Dollars)

Program Type	**Program Name**	**Projected Capital Investments**[1]	**2017 Base Rate Order**[2]	**BPU Docket No. ER17101066**[3]	**BPU Docket No. ER18101114**[4]	**Total SHP Investments**
Selective Undergrounding	West Milford UG Ckt 2 & Ckt 5	$5,089.9	$5,089.9			$5,089.9
Overhead System Construction	Harrington Park - Harriot Ave (Schraalenburgh To Bogert Mill)	830.0		$781.9		781.9
Overhead System Construction	Old Tappan - Old Tappan Rd Reconductor	331.6		102.5		102.5
Overhead System Construction	Closter - Cedar Lane (Tie to Schraalenburgh Road)	300.2			$153.8	153.8
Overhead System Construction	Oakland - Chuckanutt Drive tie	420.3			513.2	513.2
Overhead System Construction	Wyckoff - Godwin Ave mainline	452.1	452.1			452.1
Substation Flood Mitigation	Substation Flood Mitigation	300.0	300.0			300.0
Smart Grid Expansion	Distribution Automation / Smart Grid Expansion Program	8,000.0		3,165.1	3,910.6	7,075.7
	Total Storm Hardening Programs	$15,724.1	$5,842.0	$4,049.5	$4,577.6	$14,469.1

[1] The Storm Hardening Program consisted of capital investments of up to $15,724,100 over a period of three years pursuant to the Board's Decision and Order Approving Stipulation, issued January 28, 2016 *I/M/O the Verified Petition of Rockland Electric Company for Establishment of a Storm Hardening Surcharge* (BPU Docket No. ER14030250).

[2] The total project costs were rolled into the Company's electric rate base during its last electric base rate case (i.e., BPU Docket No. ER16050428) pursuant to the Board's February 22, 2017 Order Approving Stipulation ("2017 Base Rate Order").

[3] The total projects costs were included for recovery in electric base rates pursuant to the Board's Decision and Order Approving Stipulation, issued March 26, 2018 *I/M/O the Petition of Rockland Electric Company for Approval of Electric Base Rate Adjustments Pursuant to Storm Hardening Program* (BPU Docket No. ER17101066).

[4] The total projects costs were included for recovery in electric base rates pursuant to the Board's Decision and Order Approving Stipulation, issued March 13, 2019 *I/M/O the Petition of Rockland Electric Company for Approval of Electric Base Rate Adjustments Pursuant to Storm Hardening Program* (BPU Docket No. ER18101114).

ROCKLAND ELECTRIC COMPANY
DIRECT TESTIMONY OF
ELECTRIC RATE PANEL

BPU Docket No. ____________

Table of Contents

I. INTRODUCTION

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

A. Cheryl Ruggiero, Lucy Villeta, and Shajan Jacob, 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. **(Ruggiero)** We are all employed by Consolidated Edison Company of New York, Inc. ("Con Edison"), the corporate affiliate of Rockland Electric Company ("RECO" or the "Company"). I am Department Manager of the Orange and Rockland ("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 submitted testimony before the New Jersey Board of Public Utilities ("BPU"), the Pennsylvania Public Utility Commission ("PAPUC") and the New York Public Service Commission ("NYPSC").

(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 submitted testimony before the BPU, PAPUC, and NYPSC.

(Jacob) I am a Project Manager in the O&R Rate Design section of the Rate Engineering Department. I received a Bachelor of Science Degree in Chemistry from the University of Kerala in 1977, a Bachelor of Business Administration from Saint Leo University in 1998, and a Master of Business Administration Degree in Finance from Rollins College in 1999. I began my employment with Con Edison in 2006 in the Rate Engineering Department as a Senior Analyst and, since then, I have held positions with increasing responsibility. I was promoted to my current position in July 2013. I am a Certified Energy Manager, which I earned from the Association of Energy Engineers in 2003, and I am also a Registered Gas Distribution Professional, which I earned from the Gas Technology Institute in 2010. I have submitted testimony before the NYPSC.

II. PURPOSE OF TESTIMONY

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

A. We will present:

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

(2) The Staff-endorsed ECOS study, which is a variation of the Company-sponsored ECOS study developed in compliance with the BPU's February 22, 2017 Order Approving Stipulation in BPU Docket No. ER16050428 ("2017 Rate Order").

(3) The Company's proposed revenue allocation and rate design, including the impact of the proposed rate changes on customers' bills;

(4) The revenue allocation and rate design associated with the use of the Staff-endorsed ECOS study;

(5) Proposed changes to standby rate provisions;

(6) Proposed changes to the Company's lighting service classifications ("SCs"); and

(7) The Company's other proposed tariff revisions.

III. 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 2016" and identified as Exhibit P-8, Schedule 1.

Q. Was the Company-sponsored ECOS study prepared under your direction and supervision?

A. Yes.

Q. What time period does the Company-sponsored ECOS study cover?

A. It covers RECO's operations for calendar year 2016.

Q. What is the scope of the Company-sponsored 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 excluded from this study.

Q. What electric revenues are reflected in the Company-sponsored ECOS study?

A. Electric revenues reflect 2016 billing determinants priced at April 2019 rates.

Q. What customer classes are analyzed in the Company-sponsored ECOS study?

A. A description of the type of customers served under each SC is shown on pages 8 through 9 of the Explanation of Costing Methods and Tabular Results ("explanatory notes") in Schedule 1. These classes are incorporated in the Company-sponsored ECOS study starting in column (7) on each Table on pages 2 through 4.

Q. How are the results of the Company-sponsored ECOS study expressed?

A. The results 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 the Company-sponsored ECOS study?

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

Q. What are the class rates of return shown in the Company-sponsored ECOS study?

A. The following class rates of return are shown on Table 1, Pages 1 - 2, and Line 16:

- Total Residential – 2.24%;
- Total C&I – 10.98%;
- Municipal Lighting – 11.45%;
- Private Lighting – 1.38%; and
- Total Primary – 13.17%.

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 Company-sponsored ECOS study contain an analysis of customer costs by class of service?

A. Yes. Please refer to Table 6, Pages 1-2, and Line 14, of the Company-sponsored ECOS study. The monthly customer costs by class are as follows:

- Total Residential – $23.08;
- Total C&I – $54.55;

- Municipal Lighting – $1,940.61;
- Private Lighting – $46.21; and
- Total Primary – $681.34.

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 the Company-sponsored ECOS study. Please describe the procedures followed in preparation of this study.

A. There are two main steps in the preparation of the Company-sponsored 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 the Company-sponsored 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 caused 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. Revenue-related costs are general costs associated with conducting utility operations, such as the state income tax expense incurred by the Company.

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 the methodology used in the Company-sponsored ECOS study differ from the study RECO filed in BPU Docket No. ER16050428?

A. No. The Company employed the same methodology in preparing both studies.

IV. STAFF-ENDORSED ECOS STUDY

Q. Please describe the Staff-endorsed ECOS study.

A. In the Stipulation of Settlement in ER16050428, the Company agreed to provide a cost of service study prepared using the Average and Peak methodology described in paragraph 19 of the Stipulation of Settlement in RECO’s 2006 base rate case (BPU Docket No. ER06060483). The Company reserves and retains the right to oppose the methodology or results of the Staff-endorsed 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 2016” and identified as Exhibit P-8, Schedule 2. Please note that, although in this testimony we refer to the Staff-endorsed ECOS study as “Staff-endorsed” or “Staff method” or “Staff advocated” based on the prior Stipulation of Settlement, we are unaware of whether Staff continues to endorse this method at this time for rate setting in this case.

Q. How does the Staff-endorsed ECOS 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 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, it does not.

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, for 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-sponsored 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 study materially differ from the Company-sponsored ECOS study?

A. Staff's method significantly alters the use of the model's output in calculating customer costs. Specifically, the Staff method entirely excludes Uncollectibles and Customer Service from customer costs and reassigns these costs to the revenue and energy function, respectively. The Staff method 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 study 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.

V. <u>REVENUE ALLOCATION AND RATE DESIGN</u>

Q. What is the basis for the distribution revenue increase for the test year, *i.e.*, the 12 months ending September 30, 2019 ("Test Year"), that you used in your proposed rate design?

A. The distribution revenue increase of $19,906,000, excluding sales and use tax ("SUT"), was provided by the Accounting Panel. 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. Before allocating the proposed distribution revenue increase among the various SCs, we realigned Test Year distribution revenues, excluding SUT, for each SC 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 and SC No. 5 Residential Space Heating 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. 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. 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 distribution revenue increase 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 large revenue impacts for the following classes: SC No. 1, SC No. 3, and SC No. 6 (Private Overhead Lighting Service - Dusk to Dawn). 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.

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

A. In addition to the mitigation adjustments described above, we implemented mitigation adjustments to limit the distribution revenue changes so that no class received a revenue decrease. SC No. 2 General Service Primary, SC No. 7 Large General Time-Of-Day Service – Primary, and SC No. 7 High Voltage Distribution 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 revenues with costs, while limiting the customer bill impacts associated with the changes.

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

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 March 31, 2019, *i.e.*, the historical period for which detailed billing data are available.

Q. How did you compute the distribution revenue increases by class applicable to the historic period?

A. We computed revenue ratios for each class by dividing the historical period distribution revenues, excluding SUT, 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. Before applying the distribution revenue increases to each SC, did you make any revenue neutral changes?

A. Yes, we made changes to the following SCs: SC Nos. 1 and 5 and SC No. 2 – General Service Secondary Demand Billed.

Q. Please describe your changes to SC Nos. 1 and 5.

A. As approved in the 2017 Rate Order, the Company, to begin the process of moving all SC No. 5 customers to SC No. 1, changed the rate structure from a three block structure in the summer and a two block structure in the winter to a two block structure in the summer and a flat rate structure in the winter so that the SC No. 5 block thresholds matched those of SC No. 1. Such a move was proposed since the special rates for these SC No. 5 space heating customers have no cost basis and do not promote statewide energy efficiency objectives.

In this proceeding, we have proposed to set equal the block rates paid by SC No. 1 and SC No. 5 customers. This change to SC No. 1 and SC No. 5 was performed on a revenue-neutral basis prior to applying the combined class-specific increase. These proposals are fully explained in the Electric Rate Panel’s "Analysis of the Impacts of Combining the Rate Structures of Service Classification Nos. 1 and 5" included in Exhibit P-5, Schedule 5.

Q. Did you propose tariff changes to eliminate the SC No. 5 class since SC Nos. 1 and 5 share the same distribution rate structure?

A. Not at this time. For full-service customers, there are different Basic Generation Service – Residential and Small Commercial Pricing (“BGS-RSCP”) charges for SC Nos. 1 and 5. The BGS-RSCP charges are determined as part of the annual statewide auction process and become effective on June 1 of each year. The Company will include a proposal to combine the SC No. 1 and SC No. 5 BGS-RSCP rates in the RECO Company Specific Addendum it files for the 2020 Statewide BGS Auction. In addition, there are different Transmission Surcharges for SC Nos. 1 and 5. The Company will include a proposal to combine the SC No. 1 and SC No. 5 Transmission Surcharges in the first Transmission Surcharge filing made immediately following Board approval of the combination of the SC No. 1 and SC No. 5 rate classes. Once there is a common set of BGS-RSCP and Transmission Surcharge rates for SC Nos. 1 and 5, the Company will make a tariff filing to eliminate SC No. 5.

Q. Please describe your changes to SC No. 2 - General Service Secondary Demand Billed.

A. As approved in the 2016 Rate Order, we continued the process of eliminating declining block rates for the SC No. 2 - General Service Secondary Demand Billed rate class. In this case, we are proposing to continue the gradual elimination of the declining block rates for this class. Specifically, we propose to eliminate 25% of the current usage rate differentials and eliminate a corresponding portion of demand rate differentials and to shift 2% of usage revenues to demand revenues. This change was performed on a revenue-neutral basis prior to applying the class-specific increase. These proposals are contained in the Electric Rate Panel’s "Analysis of the Impacts of Eliminating Block Usage Rates and Shifting Usage Revenue to Demand Revenue in Service Classification No. 2 – Secondary Demand Billed" included in Exhibit P-5, Schedule 6.

Q. Before applying the distribution revenue increase, did you revise customer charges?

A. Yes. We first compared the current customer charges for each SC to the customer costs shown on Table 6, Pages 2-4, Line 14 of the Company-sponsored ECOS study. In general, the Company-sponsored ECOS study shows customer costs that are well above the current customer charges. As such, the Company increased customer charges to be more reflective of customer costs, consistent with the Company-sponsored ECOS study, while limiting bill impacts. For example, even though the Company-sponsored ECOS study shows an embedded customer cost of $23.08 (excluding SUT) per month for SC No. 1, we increased the current customer charge from $4.25 (excluding SUT) to $6.10 (excluding SUT) considering the bill impact of the increased customer charge on low usage residential customers. We increased customer charges in the other SCs in a similar manner to better reflect customer costs while limiting bill impacts.

Q. Were there any exceptions to this approach of increasing customer costs?

A. Yes. The Company-sponsored ECOS study results for the SC No. 7 High Voltage Distribution class indicate a customer cost that is below the current customer charge. Therefore, we kept the SC No. 7 High Voltage Distribution class customer charge at its current level.

Q. After making revenue neutral changes and increasing the customer charges as described above, how were the remaining distribution revenue increases applied to each SC?

A. For non-demand billed classes, the remainder of the distribution revenue increase was applied uniformly to usage rates or, in the case of lighting classes, to luminaire charges. For demand-billed classes, the Company applied the remainder of the distribution revenue increase uniformly to demand rates only. Because the majority of distribution costs are fixed or demand-related, increasing the amount of revenue recovered through demand charges more closely aligns how costs are incurred and collected from customers.

Q. Please describe Schedules 2 through 4 of Exhibit P-5.

A. 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 9.6%.

VI. 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 2017 Rate Order required that RECO perform a rate design based on the Staff-endorsed 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 the Staff-endorsed 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. They are presented as Schedules 8 through 11 of Exhibit P-5.

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

A. No. The 2017 Rate Order references a requirement from RECO's 2006 base rate case in BPU Docket No. ER06060483 that the Company perform a rate design based on the Staff-endorsed ECOS study that allocates the requested revenue change in accordance with the classes' cost responsibilities (p. 5). We interpret this requirement to mean that no mitigation should be performed.

Q. Please describe the information contained in Schedules 8 through 11 of Exhibit P-5.

A. Based on the results of the Staff-endorsed ECOS study, Schedule 8 contains illustrative distribution rates. Schedule 9 shows the calculation of the illustrative distribution rates, including SUT. Schedule 10 shows bill impacts using the Staff-endorsed ECOS study for SC Nos. 1, 2, 5 and 7 customers at various levels of consumption. Schedule 11 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.

VII. <u>STANDBY RATES</u>

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 the Company proposed in the on-going Standby Proceeding in BPU Docket No. GO12070600, <u>I/M/O the Act Concerning the Imposition of Standby Charges Upon Distributed Generation Customers Pursuant to N.J.S.A. 48:2-21 et seq.</u>

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 proposes that standby rates would be applicable not only to 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 New Jersey. 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 during the same month. 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, to allow customers to remain being served under SC No. 2 if they are to take standby rates, the Company proposes to move the standby rate provisions out of SC No. 7 and include them as a Rider to the tariff that will be applicable to demand-billed customers served under either SC No. 2 or SC No. 7.

VIII. LIGHTING SERVICE CLASSIFICATION CHANGES

Q. What changes are you proposing to the Company's lighting service classifications, SC Nos. 4 and 6 related to light-emitting diode ("LED") luminaires?

A. Under SC Nos. 4 and 6, the Company currently offers two LED and five induction luminaires. Due to the rapidly-developing industry surrounding lighting technology, these offerings have become obsolete as newer LED luminaires have become available. Therefore, the Company is proposing to: (1) introduce new LED dusk-to-dawn luminaires under SC Nos. 4 and 6; (2) remove the current induction and LED luminaires from the list of available luminaires for installation since they are no longer available from the manufacturer; and (3) remove certain induction luminaires from the tariff because there are no current installations and the luminaires are no longer available from the manufacturer.

Q. Please describe the new luminaires you are adding.

A. The Company proposes to add seven LED street light fixtures, three LED flood light fixtures, and three LED power bracket fixtures under SC No. 6. The LED street light and flood light fixtures will also be added under SC No. 4.

Q. Please describe how you determined the rate for these new luminaires.

A. RECO developed its proposed LED rates based on a fixed charge study. The fixed charge study used the average price per fixture of each lumen class to calculate the annual cost of providing service over the life of the LED luminaire. The annual cost of providing service was levelized over the average service life of the LED luminaire to arrive at the proposed LED rates. The Company intends to use a competitive bidding process to purchase the LED luminaires. The proposed LED rates reflect the lowest quote provided to the Company. The Company assumed an average service life of 20 years for the LED luminaires and 40 years for the mast arm and the conductor.

Q. Did the Company factor operation and maintenance ("O&M") costs into its calculation of the new LED fixture rates?

A. Yes. LED luminaires generally require less maintenance than non-LED fixtures. The primary reason for this is that High Pressure Sodium and other traditional lighting fixtures require re-lamping when bulbs burn out, every four to five years. As such, in developing the annual cost of providing service, the Company reflected a reduced level of O&M costs by only including expenses associated with the replacement of a photocell on an LED luminaire. The O&M costs comprise an average of approximately 1.4% of the total LED luminaire costs. The costs for the fixture arm and wire were also included in the calculation per luminaire, but were amortized over 40 years and include O&M of 5.7% annually.

Q. Did the Company include a discount rate in its calculation?

A. Yes. In calculating the annual cost for the LED lights, RECO included an amount for return on rate base at its currently authorized pre-tax rate of return of 9.3%. This rate provides for recovery of the return on rate base required by debt and equity investors and the associated income tax incurred in providing this return to equity investors.

Q. How will these new LED fixtures be presented in the Company's tariff?

A. Because LED technology will continue to improve and RECO will be purchasing the new LED fixtures from various vendors whose specifications and prices can vary from the Company's initial purchase, the luminaire prices in the tariff for each newly proposed fixture are displayed to represent a range of wattages which fall within a respective lumen class.

Q. Would you please describe Schedule 6 of Exhibit P-5?

A. Yes. Schedule 6 lays out the new luminaires and the price per luminaire that have been included in SC Nos. 4 and 6.

Q. Is the Company proposing any other changes to SC Nos. 4 and 6?

A. Yes. The Company is proposing to remove all obsolete luminaires which do not have any current field installations from the electric tariff.

Q. Why did the Company propose this change?

A. Many of the older vintage luminaire offerings in the Company's electric tariff are no longer in use in the service territory and are currently not available for installation under SC Nos. 4 and 6 because they are no longer available for purchase from the manufacturers. Therefore, there is no need to keep these luminaires in the Company's tariff.

IX. OTHER TARIFF CHANGES

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

A. We are proposing the following: (a) updates to the extension of lines and facilities fees contained in General Information Section No. 17; and (b) extension of the applicability of SC No. 3.

Q. Please describe the proposed changes to General Information Section No. 17, Extension of Lines and Facilities – Appendix A.

A. As explained in the testimony of the Capital Budget and Plant Addition Panel, to reflect current costs, the Company has updated the charges applicable to extensions of lines and facilities. Specifically, the unit charges contained in Exhibits I, II, III and IV of General Information Section No. 17 have been updated to reflect current costs.

Q. Please describe your change to the applicability of SC No. 3.

A. Currently, SC No. 3 is a voluntary time-of-day ("TOD") SC applicable to residential customers where an approved electric storage heater is used for the customer's entire water heating requirements and/or permanently installed electric space heating equipment is the sole source of space heating, excluding fire places, on the premises. The Company has had inquiries from customers with plug-in electric vehicles ("PEVs") who are looking to take service under a TOD residential rate structure. Currently, there is no such residential rate structure; therefore, the Company proposes to extend the availability of SC No. 3 to all residential customers, including those customers with PEVs. For such customers with PEVs, the customer would be required to move their entire household usage to SC No. 3. The Company has also changed the title of SC No. 3 to reflect this proposed expansion.

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

A. Yes, Exhibit A to the Petition shows all tariff language changes and Exhibit B to the Petition shows these 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 SCs and construction charges included in General Information Section No. 17.

Q. Does this conclude your direct testimony?

A. Yes, it does.

I. INTRODUCTION AND PURPOSE OF TESTIMONY

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

A. Jeffrey Kalata and my business address is 4 Irving Place, New York, New York.

Matthew Kahn and my business address is 4 Irving Place, New York, New York.

Michael Rufino and my business address is 4 Irving Place, New York, New York.

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

(Kalata) We are all employed by Consolidated Edison Company of New York, Inc. ("Con Edison") with responsibilities for all tax aspects of Con Edison's New Jersey utility affiliate, Rockland Electric Company ("RECO" or the "Company"). I am Vice President of Tax at Con Edison. I earned a Bachelor of Science degree in Business Administration with a concentration in accounting from Bowling Green State University. I joined Coopers & Lybrand LLC in 1986 and held a number of financial and audit positions before leaving as Senior Manager of Business

Assurance in 1997 to serve as Group Accounting Manager for North American Refractories Co. with responsibilities for all financial reporting, accounting and tax functions. I joined FirstEnergy Corp. and was named Assistant Controller in October 1999. At FirstEnergy, I had responsibilities for various accounting areas (accounts payable, payroll, property accounting and budgeting/planning), and was responsible for oversight of the external financial reporting and accounting research activities for FirstEnergy and its subsidiaries. In 2007, I transferred to FirstEnergy's tax department as Director, Tax, to head the tax accounting function over income taxes and general taxes. In 2013, I joined Con Edison's tax department as Director, Tax, and am responsible for direct activities over the income tax accounting and compliance groups, as well as the book and tax depreciation groups.

I have testified as an expert witness in utility rate cases in Ohio and assisted in the preparation of rate cases in New York, Pennsylvania, New Jersey and West Virginia. I took an active role in implementing the provisions of the Federal Tax Cuts and Job Act of 2017 ("TCJA") for RECO in the Board's proceeding addressing the TCJA and RECO's TCJA filing in *I/M/O The New Jersey Board Of Public Utilities' Consideration Of The Tax Cuts And Jobs Act Of 2017; I/M/O the Petition of Rockland Electric Company For Approval Of Revised Rates (Effective on an Interim Basis April 1, 2018) To Reflect The Reduction Under The Tax Cuts And Jobs Act Of 2017,* BPU Docket Nos. AX18010001 and ER18030236 ("RECO TCJA Proceeding"). I am an active member of the Edison Electric Institute Taxation Committee and American Gas Association Taxation Committee. I am a Certified Public Accountant in the State of Ohio and a member of the American Institute of Certified Public Accountants, the Ohio Society of Certified Public Accountants and Chartered Global Management Accountants.

(Kahn) I am a Section Manager in the Tax Department at Con Edison, with responsibility for the book and tax depreciation functions. I graduated from Bentley College (now Bentley University) in 2004 with an undergraduate degree in accounting and completed a master's degree in taxation at Bentley University in 2010. I have been employed by Con Edison since 2010. Prior to my employment at Con Edison, I worked in various roles within the accounting industry and in the field of taxation with

PricewaterhouseCoopers, LLC, and subsequently as an analyst with American Tower Corporation. I am a member of the Edison Electric Institution Taxation Committee, American Gas Association Taxation Committee and the Society of Depreciation Professionals.

I submitted testimony as an expert witness in utility rate cases in New York and New Jersey. In addition, I was an active participant in responding on behalf of RECO in the RECO TCJA Proceeding.

(Rufino) I earned a Bachelor of Science degree in Business Administration with a concentration in accounting from Pace University. I am currently pursuing a master's degree in taxation from Rutgers University. I have been employed by Con Edison since 2011 and am responsible for all income tax accounting matters, including monthly and quarterly tax provisions and financial reporting. Prior to joining Con Edison, I held various positions in the income tax and financial accounting sections at PricewaterhouseCoopers, LLC, Plainfield Asset Management, and Deloitte.

Q. What is the purpose of the Panel's direct testimony in this proceeding?

A. The Panel discusses the impact of an event subsequent to December 31, 2017 (a “Subsequent Event”) that adjusts the amount of excess deferred federal income taxes (“EDFIT”) in RECO’s electric revenue requirements to be refunded to customers, due to the TCJA. The Panel also addresses the elimination of a duplicate tax deduction included in the Company’s regulatory filings for cost of removal.

TCJA

Q. Please discuss the requirement for consideration of Subsequent Events that may have a potential impact on the amount of EDFIT to be refunded by RECO to its customers.

A. The Board issued its Decision and Order Approving Stipulation dated June 22, 2018 (“June 2018 TCJA Order”) in the RECO TCJA Proceeding. Among other things, the June 2018 TCJA Order (pp. 3-4) established balances for protected EDIT and unprotected EDIT, and addressed the manner of amortizing and refunding those balances, respectively, as discussed further in our response to the next question. In each case, the June 2018 TCJA Order (pp. 3-4, ¶¶11, 16) provided that any changes in these balances will be addressed in the next base rate case, *i.e.*, this proceeding.

Q. Please describe the nature of any potential changes that would impact the amount of EDFIT to be refunded by RECO to its customers.

A. As noted above, there are two components of the EDFIT balances to be refunded to customers pursuant to the June 2018 TCJA Order. First, protected EDFIT amounts are subject to the normalization rules under the Internal Revenue Code, and are required to be refunded over the remaining life of the plant assets. These amounts are reversing subject to Average Rate Assumption Method ("ARAM") rates. This annual amortization of protected EDFIT amounts will be updated every time the Company calculates its deferred taxes associated with its investment in plant. Generally, the Company updates these amounts quarterly in calculating the provision for federal income tax expense. Second, there are unprotected EDFIT balances that, pursuant to the June 2018 TCJA Order (p.4, ¶11), the Company is refunding over a three-year amortization period. Both protected and unprotected balances of EDFIT are currently based on the 2017 year-end income tax provision estimates and were trued-up to actual amounts upon filing the 2017 federal income tax return for the Company. For details on the amounts reflected in the Company's calculation of the revenue requirement, please see the Accounting Panel's Exhibit P-2, Schedule 22, Page 2.

Q. Please describe the impact of the 2017 true-ups on the Company's EDFIT balances.

A. As a result of filing the 2017 federal income tax return, the Company increased its unprotected EDFIT balances to be refunded to its electric distribution customers. The balance increased by approximately $1.7 million. The Company will refund this additional $1.7 million over the remaining period of the three-year amortization established in the June 2018 TCJA Order commencing with the effective date of the rates established in this proceeding. The protected EDFIT balance increased by approximately $3.7 million and will continue to be refunded to customers over the remaining life of the assets via ARAM.

REMOVAL COSTS

Q. Please explain the update to address the elimination of a duplicate tax deduction included in the Company's regulatory filings for removal costs.

A. In this filing, the Company has made changes regarding how removal costs are reflected as flow through income tax deductions in its calculation of federal income taxes.

Q. Please explain that change and why it is necessary.

A. The Company recovers removal costs for its plant assets over the life of the plant assets via a separate allowance, as a component of book depreciation expense. Book depreciation is treated as a Schedule M “add back” to book income when determining taxable income because book depreciation, including the allowance for recovery of future removal costs, is not deductible for tax purposes. The Company also flows through the tax benefit of the tax deduction for the actual removal costs incurred each year. In other words, the Company provides an income tax benefit to its current customers for the actual expenditures incurred, while recovering an amount for removal costs.

However, the Company has inadvertently flowed through to its current customers, as a component of its flow through tax depreciation, an additional deduction from taxable income for those same actual removal costs. In calculating the flow through component of tax depreciation, the Company has historically offset its book depreciation with an amount of tax depreciation that incorrectly neutralizes the Company's current collection of the income tax expense associated with future removal costs.

Q. Is the allowance for removal costs recovered as part of book depreciation currently deductible for income tax purposes?

A. No, these removal costs are not deductible for income tax purposes. Rather, removal costs are tax deductible when actually incurred, which is normally at the end of the useful life of a plant asset.

Q. By including removal costs as part of flow through tax depreciation calculation and including the actual expenditures for removal costs incurred, was the methodology overstating the tax deduction that the Company actually has taken on its federal income tax returns?

A. No, the actual tax depreciation deducted on the Company's federal income tax returns was correct and did not factor in removal costs.

Q. How should flow through tax depreciation be calculated?

A. Flow through tax depreciation should be calculated by multiplying the tax basis for each asset by the composite book depreciation expense, <u>excluding</u> the allowance for removal costs. The flow through depreciation is then subtracted from total tax depreciation generated on plant assets that the Company can deduct on its tax returns in order to calculate the level of tax depreciation normalized.

Q. Does the Company propose to correct the error in accounting for removal costs?

A. Yes. The elimination of the removal cost component has been included in the Company’s current rate filing in order to prospectively correct for the error in accounting for removal costs. The separate allowance in book depreciation expense related to removal costs requires no offset, as the Company must recover these costs in order to finance the costs incurred to remove those assets from service. In doing so, and under a flow through method of accounting, the Company will generate a credit in its accumulated provision for depreciation for this recovery, with the actual expenditures for removal cost generating a charge to the provision for accumulated depreciation to debit the reserve and make the Company whole for its expenditures incurred for removal cost.

Q. Please describe any additional areas of concern related to the current accounting method for removal costs.

A. In calculating a flow through component of tax depreciation and offsetting the removal cost component of book depreciation, the Company is misclassifying its tax depreciation expense between a flow through and normalized temporary difference. There should be no offset to the removal cost allowance in book depreciation. In offsetting the allowance for removal cost in book depreciation by allocating too much tax depreciation as flow through, the Company has historically understated its normalized tax depreciation, and its deferred income tax expense, related to accelerated methods and flowed through benefits of accelerated depreciation and understated deferred tax obligations.

Q. As part of this rate filing, is the Company proposing to correct its accounting practice for removal costs?

A. Yes. The current method of accounting, while neutralizing the recovery of removal costs through book depreciation, is improperly flowing through tax benefits too quickly to customers and reducing the effective tax rate paid by the Company. The result is a regulatory asset that has increased on behalf of removal costs incurred and flowed through, with no consideration provided for recovery of such costs to substantiate a regulatory liability. The Company is requesting regulatory permission to prospectively correct its accounting for income taxes for removal costs. The immediate impact of this change would be to no longer neutralize the allowance for removal costs as a component of book depreciation expense in the calculation of its federal income tax expense. As a result, the Company will recognize an increase in the level of normalized accelerated depreciation and reflect higher deferred income tax liabilities that will further reduce its rate base.

Q. Please summarize the impact to customers of the correction in the Company’s accounting for removal costs in its computation of federal income tax expense in the revenue requirement.

A. There are two impacts to customers, as a result of the prospective correction in the accounting for income taxes for removal costs. First, as a result of no longer offsetting the add-back for the allowance of removal costs as a component of book depreciation expense, there is an increase in federal income tax expense in the amount of $269,000. In addition, the Company will recognize an increase of $269,000 to its electric service accumulated deferred income tax liability that will reduce the Company’s rate base. Please see the Company’s Accounting Panel exhibits (Exhibit P-3 Distribution Rate Base, and Exhibit P-2, Schedule 22, Calculation of Federal Income Tax Expense).

Q. Does that conclude your direct testimony at this time?

A. Yes, it does.

ROCKLAND ELECTRIC COMPANY
DIRECT TESTIMONY OF
KEITH C. SCERBO

Q. Please state your name and business address.

A. Keith C. Scerbo and my business address is 390 West Route 59 Spring Valley, New York 10977.

Q. What is your current position at Orange and Rockland Utilities, Inc. ("Orange and Rockland"), Rockland Electric Company's ("RECO" or the "Company") corporate parent?

A. I am the Director of Advanced Metering Infrastructure ("AMI") and Customer Meter Operations.

Q. Please describe your educational background.

A. In 1991, I graduated from the Juniata College with a Bachelor of Science Degree in Business Management.

Q. Please describe your work experience.

A. I joined Orange and Rockland in 1991 as a Customer Accounting Representative. I have since held the positions of Customer Systems Analyst – Customer Accounting, Business Analyst - Customer Information Management System ("CIMS"), Lead Business Analyst - CIMS, Sr. Specialist - CIMS, Section Manager – CIMS, and Director of New Business Services, prior to my present position.

Q. Please generally describe your current responsibilities.

A. I am responsible for projects and processes associated with Orange and Rockland's and RECO's implementation of AMI, as well as all aspects of metering.

Q. Have you previously testified before the New Jersey Board of Public Utilities ("Board") or other regulatory bodies on energy matters?

A. Yes, I submitted rebuttal testimony in BPU Docket Number ER14030250 (RECO's Storm Hardening Surcharge proceeding), and direct testimony in BPU Docket Number ER16050428 (RECO's previous electric base rate case). I also provided pre-filed and live testimony in RECO's Advanced Metering Program proceeding in BPU Docket Number ER16060524 ("RECO AMI Proceeding").

Purpose

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

A. The purpose of my testimony is to discuss the Company's progress in implementing its AMI Program in the RECO service territory, as well as the benefits provided by the AMI Program. I will address the prudency of the AMI Program, as well as the prudency of the costs associated with the AMI program. I will discuss the recovery of the costs of the legacy meters replaced by AMI meters. Finally, I will discuss the cost-based justification of RECO's opt-out fees (*i.e.*, meter reading and meter change out fees.)

Background

Q. Has the Board approved the Company's AMI Program?

A. Yes. The Board approved the Company's AMI Program in its Decision and Order, dated August 23, 2017 ("AMI Order"), in the RECO AMI Proceeding. By letter dated September 19, 2017, RECO notified the Board of its intention to proceed with the AMI Program. As directed by the AMI Order, on December 11, 2017, RECO filed with the Board (1) an AMI Implementation Plan, (2) an AMI Customer Education Plan, and (3) final AMI metrics.

Q. What is the purpose of the AMI metrics?

A. As described in the AMI Order (pp. 23-24), the AMI metrics are a mechanism providing reporting on various benefits produced by the implementation of the AMI Program and on the Company's management of the implementation of the AMI Program. The AMI Order also required the Company to provide the Board with quarterly updates on these AMI metrics.

Q. Has RECO filed quarterly metrics updates with the Board?

A. Yes. The Company has filed quarterly AMI metrics update reports ("Quarterly Reports"), including the metrics tracker (*i.e.*, the numerical list of metrics being reported on) dated April 30, 2018, July 31, 2018 (data as of June 30, 2018), October 31, 2018 (data as of September 30, 2018), January 31, 2019 (data as of December 31, 2018), and April 30, 2019 (data as of March 31, 2019). These reports provide a detailed AMI Project Plan Update, and report on numbered metrics in the areas of: Customer Engagement, Billing, Outage Management, System Operations and Environmental Benefits, Meter Deployment, Major Events, and Project Management Report. The most recent update is attached hereto as Exhibit P-6.

Q. Please describe the AMI System that the Company has deployed across its service territory.

A. The Company has deployed an AMI System comprised of three major components: (1) AMI meters, (2) an AMI communication network, and (3) AMI Information Technology ("IT") platform systems to manage two-way communications. The Company's AMI System leverages an open, standards-based architecture provided by Silver Springs Networks ("Silver Springs"). Silver Springs' open standards protocol is an industry leading solution that delivers flexibility and optimizes the benefits of the AMI platform. This technology provides the flexibility to support multiple meter vendors and multiple utility service types. Communication is managed using a two-way point-to-point mesh communication technology protocol, which will enable meters to converse directly with two-way wireless communication devices across the network. This robust network is comprised of Access Points, Relays and AMI meters. The robust nature is a result of AMI meters having the ability to find numerous paths back to the communications network including talking to neighboring AMI meters to transmit data in order to get closer to an active Access Point or Relay. In addition, there is redundancy in the cellular communications within the Access Points where the Company uses both the Verizon and AT&T networks. AMI meters will be able to transmit data directly to and receive data from the Company’s IT systems, and the consumer’s home area network which is all facilitated by the communications network. Communications will be seamless with Company systems such as the Company’s Outage Management System (“OMS”) and CIMS.

Q. What technologies and services support the Company’s AMI System?

A. They include:

- AMI Technology and Services: The AMI technology includes electric AMI meters, the two-way communications network, and the AMI “head end” IT system responsible for the coordination of the communication to all of the devices.
- MDMS Technology and Services: The Meter Data Management System (“MDMS”) is the central repository

of meter data for a number of applications across the Company and is responsible for providing complete valid data to other systems, such as CIMS, in the format and frequency they require. The MDMS is also the integration hub for AMI meter data where multiple systems can access validated data. The MDMS will support advanced meter data management requirements associated with complex rates, extensive customer engagement, and market animation in the distribution grid.

- MAMS Technology and Services: The Meter Asset Management System ("MAMS") manages the AMI meter and related metering components of the AMI System. MAMS provides the ability to manage the transfer, configuration, testing, and reporting of metering system field assets. It is designed to optimize asset tracking and manage maintenance efforts associated with the meters and communication system equipment.

Q. Please summarize the Company's progress in implementing its AMI Program, as reported in the Quarterly Reports.

A. RECO spent much of the first four months of 2018 finalizing the planning for field deployment of AMI communications equipment (*i.e.*, pole mounted Access Points and Relays) and

AMI meters. The Company began deploying communication devices in April 2018 and completed this installation (a total of 142 communication devices) in August 2018. To date, these communication devices installed in RECO's service territory have been working well with no devices powering off since being installed, even with several small storms having passed through the RECO service territory. As part of the AMI Program, the Company developed an "extended" battery solution to support communication devices. The standard battery for these devices provides up to eight hours of battery backup power. The extended battery provides up to six days of battery backup. The Company expects to commence the installation of these extended batteries in its service territory in May 2019 and be complete by August 2019.

In May 2018, the Company began AMI electric meter deployment in the Mahwah area of Bergen County. As of March 31, 2019, the Company had deployed 70,590 AMI meters or 97.47% of the meters to be deployed. The Company expects to complete the entire New Jersey service territory mass deployment of AMI meters (*i.e.*, approximately 73,000 meters) by the end of the second quarter of 2019.[1] The Company's AMI team is actively monitoring installation safety, quality, customer interaction, customer engagement and the opt-out process. New Jersey meter deployment is being managed from a warehouse leased by the Company's meter installation vendor ("MIV"), Aclara. The MIV warehouse is located in Allendale, New Jersey, in close proximity to the Route 17 corridor. In 2018, there were zero accidents/injuries as a result of AMI meter installations. This is a direct result of a safety-first approach, emphasizing safety for our customers, safety for the public and safety for our installers.

The backbone of any AMI project is the technology. The Company, in collaboration with Orange and Rockland and Consolidated Edison Company of New York, Inc., deployed the AMI Head End System, MAMS (associated data conversion and inventory KIOSKS), MDMS, Profield Meter installation system (for mobile workforce management) and customer system changes in 2017. The Company continues to monitor closely

[1] The very small category of complex billing meters for large power accounts, consisting of 84 meters, will be addressed separately outside the AMI Program's mass meter deployment. These 84 accounts/meters are aligned with a much greater number of their large power account counterparts in Orange and Rockland's New York service territory (approximately 600 meters) that are not scheduled for deployment until June 2020. It is necessary to install the meters for these customers in June 2020 to coordinate the New Jersey/New York large power account deployment effort.

these system changes, which are working well in support of the meter deployment, billing and customer engagement efforts.

The AMI Program is being managed through software updates and system enhancements (“Releases”) to increase AMI functionality. The first release occurred in May 2016 under the New York Smart Meter program and consisted of standing up the AMI Head End System, MDMS and MAMS. The second Release of AMI functionality occurred on May 7, 2018. This Release included automated meter hot socket alarms and utility-initiated meter interactions such as Power Status Verification, On Demand Reads and Remote Connect/Disconnect. The Company deployed the third Release of AMI functionality on September 30, 2018. This third Release included automated remote meter connect/disconnect and AMI data integration into the Outage Management System. A Release labeled 3.5 will be ready by June 2019. It will integrate power-off and power-on messages from AMI meters directly into the Company’s Outage Management System.

Q. Is the Company’s AMI Program fully deployed and used and useful?

A. Yes. The Company’s AMI Program related to the mass installation of AMI meters will be fully deployed and used and useful by June 30, 2019, shortly after the date of this base rate filing and well within the test year ending September 30, 2019. In addition, the installation of other AMI technology (the two-way communications network, "head end" IT system, MDMS and MAMS) has been deployed effective January 2018.

Prudency – AMI Program Benefits

Q. Please discuss the prudency of the costs the Company incurred to deploy the AMI Program.

A. As the Board recognized in the AMI Order (pp. 19-20), the AMI Program provides a variety of undisputed benefits to customers, the Company and New Jersey including those discussed below.

(1) RECO is leveraging economies of scale in contract pricing obtained by Orange and Rockland to complete the project within budget. RECO has benefited from the various AMI related contracts that Orange and Rockland has secured. The pricing contained in these contracts, based on the volumes deployed in Orange and Rockland's service territory, has been extended to RECO. Further, the IT infrastructure and IT system integration costs for integrating the Customer Information Management System and Outage Management System for Orange and Rockland's AMI deployment have been employed for RECO's customers

resulting in additional capital and labor cost savings. In addition, RECO has had the benefit of the operational experience gained from the deployment of AMI in New York in advance of the RECO deployment.

(2) The AMI Program enables customers to view granular usage data, leading to proactive customer energy management. As of March 31, 2019, 13,285 RECO customers have logged into the online customer portal (*i.e.*, the My Account Portal on oru.com) to view their detailed AMI usage information. This represents 20% of the RECO customer base with AMI meters at this early stage of the Program. Customers with commissioned AMI meters will be receiving a welcome letter six weeks post commissioning. As of March 31, 2019, the Company has sent out 51,673 welcome letters. In addition, as of March 31, 2019 RECO has given 65,642 customers access to near real time data and made it available through the My Account portal on oru.com. The number of customers viewing available usage data and engaging in proactive energy management is expected to grow over time with increased customer education and awareness.

The availability of usage data also will enable the development of third-party products and incentive programs that will further empower customers. One such product, Green Button Connect ("GBC"), is being made available for RECO's customers. GBC will give the Company's customers the ability to grant third-party vendors access to their usage data for energy management product offerings. This increased control, choice and convenience will enable our customers to better manage their energy usage.

(3) Data gleaned from the AMI Program will enable improved voltage/VAR optimization and equipment usage analysis, thereby promoting both increased system efficiency and longer equipment life and it will also reduce the duration of outages at critical facilities and allow the Company to provide information which will support New Jersey's energy efficiency efforts.

The AMI communication network will have the ability to connect to devices behind the customer's meter so that customers can start receiving signals such as for critical peak or voluntary load reductions on in-home displays or even to mobile devices thus allowing for more effective demand response programs. The AMI communication network can also be leveraged to control load at customer premises, thereby providing a new avenue for addressing periodic distribution network constraints. As the Company develops additional energy efficiency programs, the use of granular usage data will inform what the best programs may be to serve customer groups. Traditionally, a significant part of energy efficiency programs is measurement and verification. Having granular usage data will provide for more accurate measurement and verification to determine the success of programs.

(4) The AMI Program will facilitate the identification of potential problems, the detection of and response to outages (particularly during major storms) and modernize the distribution infrastructure. The integration of AMI meter messages for power on/power off, as well as the ability to ping meters, allows for faster and more accurate analysis of outages across the service territory. Also, the ability to isolate and identify single service and nested outages will allow for faster restoration. In addition, the AMI communications network will enable additional functions, such as the integration of a variety of sensors to improve the Company's knowledge of its distribution networks. This improved knowledge will facilitate the identification of potential problems or issues that may impact the grid. The data provided by AMI will help modernize the distribution infrastructure and enable more distributed energy resources (“DERs”).

(5) The AMI Program will provide a more accurate picture of its system's electrical performance which will benefit its planning and forecasting processes, as well as facilitating the incorporation of more DERs by using interval data from the AMI Program. The data from AMI will enable the Company to obtain, store and analyze actual 15-minute interval energy usage and power quality data from customer premises. By using this data as input for the Company's Integrated System Model ("ISM") and coupling it with the Company's sophisticated analysis tools, RECO will realize a more accurate simulation of system electrical performance. This will benefit the Company's electric planning and forecasting processes. Also, greater granularity within those processes improves integrated planning analysis to incorporate more DERs and potentially defer or eliminate, major capital expenditures. Simply knowing the actual voltages for every single meter along a circuit, including the very last meter on each circuit, allows for better management of the electric distribution system from the substation out to the last customer served.

(6) AMI metering will enable the Company to review the entire system as well as to monitor closely and model load characteristics, local voltage, and power quality. With

the AMI input, the entire system and generation profile can be integrated and reviewed for peaks, demand reduction, contingencies and monitoring (and future controlling) of generation sources such as solar and microgrids. Data can be summarized or aggregated to provide real-time operational awareness in the control center.

As these innovative technologies are implemented, AMI metering will enable the Company to monitor closely and model load characteristics and local voltage and power quality, so that these technologies are safely integrated with the use of smart devices in the field for the benefit of the consumer. Locational problems, even down to the secondary level, will be identified and resolved more quickly.

Q. Are there benefits associated with the automated connect/disconnect functionality of AMI and AMI meters?

A. Yes. The Company can employ this automated connect/disconnect functionality to support residential and small commercial AMI meters that have remote switch capability. The Company can now provide more timely connection or disconnection of service to those customers who are moving in or moving out of premises, thereby allowing for more timely service. Customers can now schedule connection and disconnection of service in advance with RECO. For example, a customer can call two weeks in advance of selling their home and request the specific date/time that they wish the service to be terminated. That request will sit in a pending state waiting for that date/time to arrive. When it does arrive, the automation of the AMI systems and communication network will communicate to that meter to open the switch disconnecting service. This not only provides an improved customer experience but also reduces unaccounted for usage that may occur on a “soft locked” meter while the Company awaits a new customer to contact RECO for service. Conversely, a customer who knows they will be purchasing a new home can contact RECO in advance and request service to be turned on for a certain date/time to coincide with their arrival at the home. RECO has encountered several examples, to date, where customers were on the phone with customer service representatives requesting service at a home and while standing in the home the representative was able to send a signal to those meters and turn the service on. These real-time, on demand, service activation are some of the best customer experiences a utility can provide. In addition, this functionality is being used to support collections work in the field. Customer meter technicians continue to make contact in person with customers who are eligible to have their service terminated for non-payment. However, if payment arrangements cannot be made the technician can now leave the premise instead of disconnecting the service. Once the technician completes the paperwork in the automated system a signal is sent over the air to open the switch in the meter thereby disconnecting service. Similarly, when payment is made by a customer who was disconnected for non-payment, an over the air signal is sent to the meter to close the switch in the meter thereby re-connecting service. While disconnection and reconnection of service for non-payment is not a pleasant interaction, this new remote functionality provides a marked customer experience improvement. For customers who make payment and need their service turned back on, they no longer need to wait for a technician to arrive at their home. The customer service representative can initiate an order that will send a signal to the meter to close the switch thereby providing power to the premise. As of March 31, 2019, the Company utilized remote switch functionality approximately 1,250 times.

Q. Please discuss the Company’s integration of the AMI system into the Company’s OMS, and the resulting benefits.

A. The Company completed the first round of AMI meter data integration into its OMS on September 30, 2018. This integration allows any and all AMI meters associated with an outage to be “pinged” by Company resources prior to dispatching crews to the field to investigate and effectuate repairs. The ability to “ping” a meter enhances the Company’s outage detection capability by providing confirmation that power is on or off at a particular premise. This information allows the Company to manage field crews more efficiently during restoration. During “Blue Sky” days and small-scale events from October 2018 through March 2019 the Company was able to use the “ping” capability to determine that power to customer locations was active 71 times. That is 71 distinct truck rolls that were avoided. As the Company becomes more skilled at performing a “ping” of AMI meters and the fact that the service territory will be fully deployed with AMI meters, the Company fully expects this number to grow. I would note that because the Company has not experienced a major storm since March 2018, RECO cannot yet report on the AMI system’s performance during such an event.

Q. Are there additional benefits from reduced truck rolls?

A. Yes, in addition to providing customers with accurate analysis of their power issues faster, there are environmental benefits (*i.e.*, reduced emissions) from not sending Company vehicles to those locations to determine the same result. In addition, Company vehicles can then be dispatched to locations where they can provide services to other customers.

Q. Has the Company performed any quantitative analysis of benefits and costs?

A. Yes. The Company provided a cost benefit analysis in the AMI Business Plan it submitted to the Board in the RECO AMI Proceeding, which analysis was referenced in the Board's AMI Order approving the AMI Program. That analysis reviewed project costs and benefits over a 20-year period and demonstrated benefits substantially exceeding costs.

Q. Have there been any changes to the Company's cost benefit analysis since the AMI Order (dated August 23, 2017) with regard to costs or benefits?

A. No. As indicated below, the actual project costs are well within the originally estimated project costs. The Amortization of Outmoded Assets is now $3.0 million less than what it was in 2016 but that is only due to legacy meter depreciation over the last three years. The Company continues to expect the level of benefits that were forecasted to occur in that analysis based on AMI deployment. As discussed above, the mass deployment of AMI meters is just now being completed such that there is no reason to adjust the projected benefits.

Q. What were the results of the cost benefit analysis previously submitted to the Board and referenced in its AMI Order?

A. Please see the Table 1 below showing costs and benefits in millions of dollars.

Table 1: Financial Highlights and Summary ($ in millions)

Business Case Financial View Over 20 Years	Costs
A. Costs (20 Year Total Costs)	(millions)
O&M Expense for AMI System	$12.0
Net Capital Depreciation Expense for AMI System	$12.6
Amortization of Outmoded Assets	$8.2
Sub-Total	$32.8
B. AMI Benefits (20 Year Total Benefits)	
AMI Cost Reduction Benefits	$65.0
Customer and Societal Benefits	$17.0
Sub-Total	$82.0
C. Total (20 Year Net Total)	
Benefits Less Costs	$49.2
Utility Simple Payback Period	7.2 years
Utility Discounted Payback Period	15.5 years

Prudency – Costs

Q. Please discuss the prudency of the costs the Company incurred to deploy the AMI Program.

A. As noted in the AMI Order (p. 4), the Company estimated that it would cost $16.5 million to deploy the AMI Program in the RECO service territory. The actual cost of the AMI program as of April 30, 2019 is $11,324,290 and the projected final cost is $16,200,000. The Company has implemented the AMI Program in an orderly and efficient fashion in accordance with the Implementation Plan, as demonstrated in the Quarterly Reports. The AMI Program's capital investment has been completed on schedule and under budget.

Q. What is the level of AMI expenditures are you projecting will be added to RECO's plant between April 2019 and March 2020?

A. As shown on Exhibit P-3, Schedule 12, I am projecting that approximately $1.6 million of AMI expenditures will be added to plant-in-service through March 2020. The balance of approximately $3.3 million (*i.e.,* $16.2 million less $11.3 million less $1.6 million), will be recorded on Orange and Rockland's books as part of "Joint Use Plant."

Legacy Meters

Q. What has the Board stated regarding the recovery of the costs of the legacy meters (*i.e.*, those meters replaced by AMI meters)?

A. In the AMI Order (p. 19), the Board authorized the Company to defer, in a regulatory asset, the remaining net book value of the legacy meters. The Board directed the Company in its next base rate case, *i.e.*, this base rate case, to file testimony addressing the amount of the deferral for the legacy meters and a proposal for the amortization of the deferred costs.

Q. What is the amount of the Company's remaining undepreciated, deferred investment in legacy meters?

A. As set forth in the direct testimony of the Depreciation Panel, the Company projects that upon completion of the AMI meter installation, the remaining unrecovered legacy meter costs will be approximately $5.2 million.

Q. Please explain why the Company should be authorized to recover the unrecovered legacy meter costs.

A. In the absence of the AMI Program, the costs of the legacy meters would have been recovered from customers in rates via depreciation. Indeed, the recovery of the investment in the legacy meters has been repeatedly approved in prior base rate cases. In the AMI Order, the Board authorized the Company to implement the AMI Program (and remove the existing meters), upon finding that the Program had the potential to "enable a host of benefits" (p. 20) and further the Energy Master Plan goals (p. 18). In order to implement the Board-approved AMI Program, and achieve the associated benefits, it was absolutely necessary to remove the legacy meters which resulted in the unrecovered legacy meter costs. As discussed above, the Company has demonstrated the undisputed benefits from and prudency of the AMI Program. Accordingly, the Company has included a proposal for the recovery of these legacy meter costs in this base rate filing.

Q. What is the Company proposing?

A. As discussed in the testimony of the Company's Depreciation Panel, the Company is proposing to amortize the net book value of the legacy meters over 15 years.

Opt-Out Fees

Q. Has the Company implemented the AMI opt-out fees approved by the Board in the AMI Order?

A. Yes. As authorized by the AMI Order (p. 21), the Company implemented the AMI opt-out fees via a tariff filing in June 2018. Specifically, the Company charges two fees related to customer opt-outs from the AMI Program: (1) a monthly meter reading fee of $15 monthly charge for those customers who choose not to have an AMI meter installed at their premise; and (2) a $45 meter change out fee for customers who opt-out after the AMI meter has been installed. The AMI Order authorized these fees after finding that the Company demonstrated they were in line with fees in other jurisdictions, and that the meter reading fee is consistent with basic causation principles since the fee would cover the incremental costs of manual meter reading. The Company does not propose to change the amount of either of these two fees in this rate filing.

Q. How much has the Company collected from these two fees?

A. Through March 31, 2019, the Company has collected a total of $36,225 from the opt-out fee. Through March 31, 2019, the Company has not had to perform meter change outs and has therefore collected $0 from the meter change out fee. The Accounting Panel discusses how these amounts are treated for ratemaking purposes.

Q. Should the Board continue to allow the Company to assess these two fees?

A. Definitely. The Company incurs actual costs associated with the provision of service to the customers against whom the fees are assessed that must be recovered. The monthly meter reading fee allows RECO to recover the incremental costs it incurs by manually reading the customer's meter. Similarly, the meter change-out fee allows RECO to recover the incremental costs that it incurs in changing out an AMI meter. Charging these fees to those very customers who require the Company to incur these incremental costs is consistent with fundamental cost causation principles.

Q. Does the current opt-out monthly manual meter reading fee of $15.00 cover the cost of the actual work associated with the manual meter reading?

A. No, the level of the opt-out fee is below the actual costs for the work of manual meter reading for the opt-out customers. The actual cost is now $17.00 per month per meter. This current higher cost of monthly manual meter reading is driven by increases in labor costs since the time of the issuance of the AMI Order. The determination of the $17.00 cost per read is based on meter reader labor costs per hour divided by six reads per hour.

Q. Is the Company requesting an increase in the monthly manual meter reading fee for opt-out customers?

A. No. The Company believes it would be reasonable to wait until a future rate filing to adjust the fee because the mass deployment of AMI meters is nearing completion. The Company believes it would be better to review this charge after meter readers have had additional experience focusing on reading the final number of opt-out meters monthly following removal of legacy meters and deployment of AMI meters.

Q. How many RECO customers have opted-out of the AMI Program?

A. As of March 31, 2019, 644 accounts have opted-out of RECO’s AMI Program.

Q. Does that conclude your direct testimony at this time?

A. Yes, it does.

ROCKLAND ELECTRIC COMPANY
RATE OF RETURN

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BEFORE THE
NEW JERSEY BOARD OF PUBLIC UTILITIES

ROCKLAND ELECTRIC COMPANY

BPU DOCKET NO. __________

DIRECT TESTIMONY OF JAMES H. VANDER WEIDE
ON BEHALF OF
ROCKLAND ELECTRIC COMPANY

I. INTRODUCTION AND PURPOSE

Q. Please state your name, title, and business address.

A. My name is James H. Vander Weide. I am President of Financial Strategy Associates, a firm that provides strategic and financial consulting services to business clients. My business address is 3606 Stoneybrook Drive, Durham, North Carolina 27705.

Q. Please describe your educational background and prior academic experience.

A. I graduated from Cornell University with a Bachelor's Degree in Economics and from Northwestern University with a Ph.D. in Finance. After joining the faculty of the School of Business at Duke University, I was named Assistant Professor, Associate Professor, Professor, and then Research Professor. I have published research in the areas of finance and economics and taught courses in these fields at Duke for more than thirty-five years. I am now retired from my teaching duties at Duke. A summary of my research, teaching, and other professional experience is presented in Appendix 1.

Q. Have you previously testified on financial or economic issues?

A. Yes. As an expert on financial and economic theory and practice, I have participated in more than five hundred regulatory and legal proceedings before the public service commissions of forty-five states and four Canadian provinces, the United States Congress, the Federal Energy Regulatory Commission, the National Energy Board (Canada), the Federal Communications Commission, the Canadian Radio-Television and Telecommunications Commission, the National Telecommunications and Information Administration, the insurance commissions of five states, the Iowa State Board of Tax Review, the National Association of Securities Dealers, and the North Carolina Property Tax Commission. In addition, I have prepared expert testimony in proceedings before the United States District Court for the District of Nebraska; the United States District Court for the District of New Hampshire; the United States District Court for the District of Northern Illinois; the United States District Court for the Eastern District of North Carolina; the United States District Court for the Northern District of California; the United States District Court for the Eastern District of Michigan; the United States Bankruptcy Court for the Southern District of West Virginia; the Montana Second Judicial District Court, Silver Bow County; the Superior Court, North Carolina; and the Supreme Court of the State of New York.

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

A. I have been asked by Rockland Electric Company ("RECO" or the "Company") to prepare an independent appraisal of the required rate of return on equity for the Company's regulated utility operations in New Jersey and to recommend an allowed rate of return on equity ("ROE") for these operations that is fair, that allows the Company to attract capital on reasonable terms, and that allows the Company to maintain its financial integrity. RECO is a wholly-owned subsidiary of Orange and Rockland Utilities, Inc. ("O&R"), and O&R is a wholly-owned subsidiary of Consolidated Edison, Inc. ("CEI").

II. SUMMARY OF TESTIMONY

Q. How do you estimate RECO's required rate of return on equity?

A. I estimate RECO's required rate of return equity by: (1) applying several standard cost of equity estimation methods to financial data for a proxy group of electric utilities of comparable risk; and (2) calculating the average expected rate of return on book equity for the group of electric utilities.

Q. Why do you apply cost of equity methods to a proxy group of comparable risk utilities rather than solely to the Company?

A. I apply my cost of equity methods to a proxy group of comparable risk utilities because: (1) the Company is not publicly-traded; and (2) standard cost of equity methods such as the discounted cash flow ("DCF"), risk premium, and capital asset pricing model ("CAPM") require inputs of quantities that are not easily measured. Because these inputs can only be estimated, there is naturally some degree of uncertainty surrounding the estimate of the cost of equity for each company. However, the uncertainty in the estimate of the cost of equity for an individual company can be greatly reduced by applying cost of equity methods to a large sample of comparable companies. Intuitively, unusually high estimates for some individual companies are offset by unusually low estimates for other individual companies. Thus, financial economists invariably apply cost of equity methods to one or more proxy groups of comparable companies. In utility regulation, the practice of using comparable companies, called the comparable company approach, is further supported by the United States Supreme Court standard that the utility should be allowed to earn a return on its investment that is commensurate with returns being earned on other investments of comparable risk.[1] I note that the Board has previously accepted the practice of calculating the Company's required rate of return on equity by applying cost of equity methods to a proxy group of comparable risk utilities in the Company's prior rate cases (for example, BPU Docket No. ER16050428 and BPU Docket No. ER1311135).

Q. Why do you believe it is important to use more than one analytical approach to estimate the Company's cost of equity?

A. Because the cost of equity is not directly observable, it must be estimated based on both quantitative and qualitative information. When faced with the task of estimating the cost of equity, analysts and investors gather and evaluate as much relevant data as reasonably can be analyzed. As a result, a number of models have been developed to estimate the cost of equity. However, as a practical matter, all models available for estimating the cost of equity are subject to limiting assumptions or other methodological constraints.

Financial models simply are tools to be used in the ROE estimation process, and strict adherence to any single approach, or to the specific results of any single approach, can lead to flawed or misleading conclusions. This position

[1] *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923) ("Bluefield Water Works")*; Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("Hope Natural Gas")

is consistent with the finding in both *Bluefield Water Works* and *Hope Natural Gas* that it is the analytical result, as opposed to the methodology, that is controlling in arriving at ROE determinations. Thus, a reasonable ROE estimate appropriately considers alternate methodologies and the reasonableness of their individual and collective results.

Consequently, I believe it is prudent and appropriate to use multiple methodologies in order to reduce the uncertainty that may be associated with the assumptions and inputs of any single approach. It is further appropriate to apply reasoned judgment in considering the results generated by each individual approach.

Q. What required rate of return on equity do you find for the utility operations of RECO in this proceeding?

A. On the basis of my studies, I find that the required rate of return on equity for the utility operations of RECO is 10.4 percent. This conclusion is based on my application of standard cost of equity estimation techniques, including the DCF model and the CAPM, to a proxy group of electric utilities of comparable risk and my calculation of the average expected rate of return on book equity for that group of electric utilities.

Q. Do you have exhibits accompanying your testimony?

A. Yes. I have prepared or supervised the preparation of Exhibit ___(JVW-1), which consists of ten schedules and five appendices that accompany my direct testimony.

III. ECONOMIC AND LEGAL PRINCIPLES

Q. What is the economic definition of the cost of capital?

A. Economists define the cost of capital as the return investors expect to receive on alternative investments of comparable risk.

Q. What role does the cost of capital play in the allocation of capital in the capital markets?

A. The cost of capital is a hurdle rate, or cut-off rate, for investment in a company or project. Investors will only invest in a company or project if they expect to earn a return on their investment that is at least as large as the return they expect to receive on other investments of comparable risk.

Q. Do all investors have the same position in the company?

A. No. Debt investors have a fixed claim on a company's assets and income that must be paid prior to any payment to the company's equity investors. Because the company's equity investors have only a residual claim on the company's assets and income, equity investments are riskier than debt investments. Thus, the cost of equity exceeds the cost of debt.

Q. What is the overall or average cost of capital?

A. The overall or average cost of capital is a weighted average of the cost of debt and cost of equity, where the weights are the percentages of debt and equity in a company's capital structure.

Q. Can you illustrate the calculation of the overall or weighted average cost of capital?

A. Yes. Assume that the cost of debt is 7 percent, the cost of equity is 13 percent, and the percentages of debt and equity in the company's capital structure are 50 percent and 50 percent, respectively. Then the weighted average cost of capital is expressed by 0.50 times 7 percent plus 0.50 times 13 percent, or 10.0 percent.

Q. How do economists define the cost of equity?

A. Economists define the cost of equity as the return investors expect to receive on alternative equity investments of comparable risk. Because the return on an equity investment of comparable risk is not a contractual return, the cost of equity is more difficult to measure than the cost of debt. However, as I have already noted, there is agreement among economists that the cost of equity is greater than the cost of debt. There is also agreement among economists that the cost of equity, like the cost of debt, is both forward looking and market based.

Q. How do economists measure the percentages of debt and equity in a company's capital structure?

A. Economists measure the percentages of debt and equity in a company's capital structure by first calculating the market value of the company's debt and the market value of its equity. Economists then calculate the percentage of debt by the ratio of the market value of debt to the combined market value of debt and equity, and the percentage of equity by the ratio of the market value of equity to the combined market value of debt and equity. For example, if a company's debt has a market value of $25 million and its equity has a market value of

$75 million, then its total market capitalization is $100 million, and its capital structure contains 25 percent debt and 75 percent equity.

Q. Why do economists measure a company's capital structure in terms of the market values of its debt and equity?

A. Economists measure a company's capital structure in terms of the market values of its debt and equity because: (1) the weighted average cost of capital is defined as the return investors expect to earn on a portfolio of the company's debt and equity securities; (2) investors measure the expected return and risk on their portfolios using market value weights, not book value weights; and (3) market values are the best measures of the amounts of debt and equity investors have invested in the company on a going forward basis.

Q. Why do investors measure the expected return and risk on their investment portfolios using market value weights rather than book value weights?

A. Investors measure the expected return and risk on their investment portfolios using market value weights because: (1) the expected return on a portfolio is calculated by comparing the expected value of the portfolio at the end of the investment period to its current value; (2) the risk of a portfolio is calculated by examining the variability of the end-of-period return on the portfolio around the expected value; and (3) market values are the best measure of the current value of the portfolio. From the investor's point of view, the historical cost, or book value of their investment, is generally a poor indicator of the portfolio's current value.

Q. Is the economic definition of the weighted average cost of capital consistent with regulators' traditional definition of the average cost of capital?

A. No. The economic definition of the weighted average cost of capital is based on the market costs of debt and equity, the market value percentages of debt and equity in a company's capital structure, and the future expected risk of investing in the company. In contrast, regulators have traditionally defined the weighted average cost of capital using the embedded cost of debt and the book or accounting values of debt and equity shown on a company's balance sheet. A company's market value capital structure generally differs from its book value capital structure because the market value capital structure reflects the current values of the company's debt and equity in the capital markets, whereas the company's book value capital structure reflects the values of the company's debt and equity based on historical accounting costs.

Q. Will investors have an opportunity to earn a fair return on the value of their equity investment in the company if regulators calculate the weighted average cost of capital using the book value of equity in the company's capital structure?

A. No. Investors will only have an opportunity to earn a fair return on the value of their equity investment if regulators either calculate the weighted average cost of capital using the market value of equity in the company's capital structure or adjust the cost of equity for the difference in the financial risk reflected in the market value capital structures of the proxy companies and the financial risk reflected in the company's rate making capital structure.

Q. Are the economic principles regarding the fair return for capital recognized in any United States Supreme court cases?

A. Yes. These economic principles, relating to the supply of and demand for capital, are recognized in two United States Supreme Court cases: (1) *Bluefield Water Works*; and (2) *Hope Natural Gas Co*. In the *Bluefield Water Works* case, the Court stated:

> A public utility is entitled to such rates as will permit it to earn a return upon the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit, and enable it to raise the money necessary for the proper discharge of its public duties. [*Bluefield Water Works and Improvement Co. v. Public Service Comm'n.* 262 U.S. 679, 692 (1923).]

The Supreme Court recognizes here that: (1) a regulated company cannot remain financially sound unless the return it is allowed to earn on the value of its property is at least equal to the cost of capital (the principle relating to the demand for capital); and (2) a regulated company will not be able to attract capital if it does not offer investors an opportunity to earn a return on their investment equal to the return they expect to earn on other investments of similar risk (the principle relating to the supply of capital).

In the *Hope Natural Gas* case, the Supreme Court reiterates the financial soundness and capital attraction principles of the *Bluefield Water Works* case:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock... By that standard the return to the equity owner should be commensurate with returns on investments

> in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. [*Federal Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 591, 603 (1944).]

The Supreme Court recognizes that the fair rate of return on equity should be: (1) comparable to returns investors expect to earn on other investments of similar risk; (2) sufficient to assure confidence in the company's financial integrity; and (3) adequate to maintain and support the company's credit and to attract capital.

IV. RECO'S REQUIRED RATE OF RETURN ON EQUITY

Q. How do you estimate the required rate of return on equity for RECO's electric utility operations?

A. I estimate RECO's required rate of return on equity by applying several cost of equity estimation methods to a group of comparable-risk electric utilities and by calculating the average expected rate of return on book equity for the comparable group of electric utilities.

Q. What methods do you use to estimate the cost of equity for RECO's electric utility operations?

A. I use the DCF model and the CAPM. The DCF model assumes that the current market price of a company's stock is equal to the discounted value of all expected future cash flows. The CAPM assumes that the investor's required rate of return on equity is equal to the expected risk-free rate of interest plus the product of a company-specific risk factor, beta, and the expected risk premium on the market portfolio.

Q. How do you use the comparable earnings method to calculate RECO's required rate of return on equity?

A. I use the comparable earnings method to estimate RECO's required rate of return on equity by calculating the average expected rate of return on book equity for a comparable group of electric utilities.

Q. Is the comparable earnings method consistent with the United States Supreme Court's fair rate of return standard?

A. Yes. The United States Supreme Court states in the *Hope Natural Gas* case that the "return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks." [*Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).] This language is consistent with both a capital attraction standard, as measured by the cost of equity, and a comparable earnings standard, as measured by calculating the expected rate of return on equity for a group of comparable-risk companies.

A. THE DISCOUNTED CASH FLOW MODEL

Q. Please describe the DCF model.

A. The DCF model is based on the assumption that investors value an asset because they expect to receive a sequence of cash flows from owning the asset. Thus, investors value an investment in a bond because they expect to receive a sequence of semi-annual coupon payments over the life of the bond and a terminal payment equal to the bond's face value at the time the bond matures. Likewise, investors value an investment in a company's stock because they expect to receive a sequence of dividend payments and, perhaps, expect to sell the stock at a higher price sometime in the future.

A second fundamental principle of the DCF model is that investors value a dollar received in the future less than a dollar received today. A future dollar is valued less than a current dollar because investors could invest a current dollar in an interest earning account and increase their wealth. This principle is called the time value of money.

Applying the two fundamental DCF principles noted above to an investment in a bond leads to the conclusion that investors value their investment in the bond on the basis of the present value of the bond's future cash flows. Thus, the price of the bond should be equal to:

EQUATION 1

$$P_B = \frac{C}{(1+i)} + \frac{C}{(1+i)^2} + \ldots + \frac{C+F}{(1+i)^n}$$

where:

P_B	=	Bond price;
C	=	Cash value of the coupon payment (assumed for notational convenience to occur annually rather than semi-annually);
F	=	Face value of the bond;
i	=	The rate of interest the investor could earn by investing his money in an alternative bond of equal risk; and
n	=	The number of periods before the bond matures.

Applying these same principles to an investment in a company's stock suggests that the price of the stock should be equal to:

EQUATION 2

$$P_s = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_n + P_n}{(1+k)^n}$$

where:

P_S	=	Current price of the company's stock;
$D_1, D_2 ... D_n$	=	Expected annual dividend per share on the company's stock;
P_n	=	Price per share of stock at the time the investor expects to sell the stock; and
k	=	Return the investor expects to earn on alternative investments of the same risk, i.e., the investor's required rate of return.

Equation (2) is frequently called the annual discounted cash flow model of stock valuation. Assuming that dividends grow at a constant annual rate, g, this equation can be solved for k, the cost of equity. The resulting cost of equity equation is $k = D_1/P_s + g$, where k is the cost of equity, D_1 is the expected next period annual dividend, P_s is the current price of the stock, and g is the constant annual growth rate in earnings, dividends, and book value per share. The term D_1/P_s is called the expected dividend yield component of the annual DCF model, and the term g is called the expected growth component of the annual DCF model.

Q. Are you recommending that the annual DCF model be used to estimate the cost of equity for RECO's electric utility operations?

A. No. The DCF model assumes that a company's stock price is equal to the present discounted value of all expected future dividends. The annual DCF model is only a correct expression of the present value of future dividends if dividends are paid annually at the end of each year. Because the companies in my comparable group all pay dividends quarterly, the current market price that investors are willing to pay reflects the expected quarterly receipt of dividends. Therefore, a quarterly DCF model should be used to estimate the cost of equity for these companies. The quarterly DCF model differs from the annual DCF model in that it expresses a company's price as the present value of a quarterly stream of dividend payments. A complete analysis of the implications of the quarterly payment of dividends on the DCF model is provided in Appendix 2. For the reasons cited there, I employed the quarterly DCF model throughout my calculations, even though the results of the quarterly DCF model for my companies are approximately equal to the results of a properly applied annual DCF model.

Q. Please describe the quarterly DCF model you use.

A. The quarterly DCF model I use is described on Schedule 1 and in Appendix 2. The quarterly DCF equation shows that the cost of equity is: the sum of the future expected dividend yield and the growth rate, where the dividend in the dividend yield is the equivalent future value of the four quarterly dividends at the end of the year, and the growth rate is the expected growth in dividends or earnings per share.

Q. How do you estimate the quarterly dividend payments in your quarterly DCF model?

A. The quarterly DCF model requires an estimate of the dividends, d_1, d_2, d_3, and d_4, investors expect to receive over the next four quarters. I estimate the next four quarterly dividends by multiplying the previous four quarterly dividends by (1 + g), where *g* is the expected growth rate.

Q. Can you illustrate how you estimate the next four quarterly dividends with data for a specific company in your proxy group of electric utilities?

A. Yes. In the case of Alliant Energy, the first electric utility company shown in Schedule 1, the last four quarterly dividends are each equal to 0.335 and the expected growth rate is 6.9 percent. Thus dividends, d_1, d_2, d_3, and d_4 are equal to 0.358 [0.335 x (1 + 0.069) = 0.358]. (As noted previously, the logic underlying this procedure is described in Appendix 2.)

Q. How do you estimate the growth component of the quarterly DCF model?

A. I use the I/B/E/S analysts' estimates of future earnings per share ("EPS") growth reported by Refinitiv (formerly Thomson Reuters).

Q. What are the analysts' estimates of future EPS growth?

A. As part of their research, financial analysts working at Wall Street companies periodically estimate EPS growth for each company they follow. The EPS forecasts for each company are then published. Investors who are contemplating purchasing or selling shares in individual companies review the forecasts. These estimates represent three- to five-year forecasts of EPS growth.

Q. What is I/B/E/S?

A. I/B/E/S is a database that reports analysts' EPS growth forecasts for a broad group of companies. The forecasts are expressed in terms of a mean forecast and a standard deviation of forecast for each company. Investors use the mean forecast as an estimate of future company performance.

Q. Why do you use the I/B/E/S growth estimates?

A. The I/B/E/S growth rates: (1) are widely circulated in the financial community, (2) include the projections of reputable financial analysts who develop estimates of future EPS growth, (3) are reported on a timely basis to investors, and (4) are widely used by institutional and other investors.

Q. Why do you rely on analysts' projections of future EPS growth in estimating the investors' expected growth rate rather than looking at past historical growth rates?

A. I rely on analysts' projections of future EPS growth because there is considerable empirical evidence that investors use analysts' EPS growth forecasts to estimate future earnings growth.

Q. Have you performed any studies concerning the use of analysts' forecasts as an estimate of investors' expected growth rate, g?

A. Yes. I prepared a study with Willard T. Carleton, Professor Emeritus of Finance at the University of Arizona, which is described in a paper entitled "Investor Growth Expectations and Stock Prices: the Analysts versus History," published in the Spring 1988 edition of *The Journal of Portfolio Management*.

Q. Please summarize the results of your study.

A. First, we performed a correlation analysis to identify the historically-oriented growth rates which best described a company's stock price. Then we did a regression study comparing the historical growth rates with the average I/B/E/S analysts' forecasts. In every case, the regression equations containing the average of analysts' forecasts statistically outperformed the regression equations containing the historical growth estimates. These results are consistent with those found by Cragg and Malkiel, the early major research in this area (John G. Cragg and Burton G. Malkiel, *Expectations and the Structure of Share Prices*, University of Chicago Press, 1982). These results are also consistent with the hypothesis that investors use analysts' forecasts, rather than historically-oriented or sustainable growth calculations, in making stock buy and sell decisions. They provide overwhelming evidence that the analysts' forecasts of future growth are superior to historically-oriented or sustainable growth measures in predicting a company's stock price. Researchers at State Street Financial Advisors updated my study in 2004, and their results continue to confirm that analysts' growth forecasts are superior to historically-oriented growth measures in predicting a company's stock price.

Q. What stock prices do you use in your DCF model?

A. I use a simple average of the monthly high and low stock prices for each company for the three-month period ended January 2019. These high and low stock prices were obtained from Thomson Reuters.

Q. Why do you use the three-month average stock price in applying the DCF method?

A. I use the three-month average stock price in applying the DCF method because stock prices fluctuate daily, while financial analysts' forecasts for a given company are generally changed less frequently, often on a quarterly basis. Thus, to match the stock price with an earnings forecast, it is appropriate to use average stock prices over a three-month period.

Q. Do you include an allowance for flotation costs in your DCF analysis?

A. Yes. I include a five percent allowance for flotation costs in my DCF calculations.

Q. Please explain your inclusion of flotation costs.

A. All companies that have sold securities in the capital markets have incurred some level of flotation costs, including underwriters' commissions, legal fees, and printing expenses, for example. These costs are withheld from the proceeds of the stock sale or are paid separately, and must be recovered over the life of the equity issue. Costs vary depending upon the size of the issue, the type of registration method used and other factors, but in general these costs range between three percent and five percent of the proceeds from the issue [see Lee, Inmoo, Scott Lochhead, Jay Ritter, and Quanshui Zhao, "The Costs of Raising Capital," *The Journal of Financial Research*, Vol. XIX No 1 (Spring 1996), 59-74, and Clifford W. Smith, "Alternative Methods for Raising Capital," *Journal of Financial Economics* 5 (1977) 273-307]. In addition to these costs, for large equity issues (in relation to outstanding equity shares), there is likely to be a decline in price associated with the sale of shares to the public. On average, the decline due to market pressure has been estimated at two percent to three percent [see Richard H. Pettway, "The Effects of New Equity Sales upon Utility Share Prices," *Public Utilities Fortnightly*, May 10, 1984, 35—39]. Thus, the total flotation cost, including both issuance expense and stock price decline, generally ranges from five percent to eight percent of the proceeds of an equity issue. I believe a combined five percent allowance for flotation costs is a conservative estimate that should be used in applying the DCF model in these proceedings. A complete explanation of the need for flotation costs is contained in Appendix 3.

Q. How do you select your electric utility proxy company group?

A. I select all the electric utilities followed by Value Line that: (1) have an investment-grade bond rating; (2) paid dividends during every quarter of the last two years; (3) did not decrease dividends during any quarter of the past two years; (4) have a positive I/B/E/S long-term growth forecast; and (5) are not the subject of a merger offer that has not been completed. I also note that each of the utilities included in my comparable group has a Value Line Safety Rank of 1, 2, or 3.

Q. Why do you eliminate companies that have either decreased or eliminated their dividend in the past two years?

A. The DCF model requires the assumption that dividends will grow at a constant rate into the indefinite future. If a company has either decreased or eliminated its dividend in recent years, the assumption that the company's dividend will grow at the same rate into the indefinite future becomes questionable.

Q. Why do you eliminate companies that are the subject of a merger offer that has not been completed?

A. A merger announcement can sometimes have a significant impact on a company's stock price because of anticipated merger-related cost savings and new market opportunities. Analysts' growth forecasts, on the other hand, are necessarily related to companies as they currently exist, and do not reflect investors' views of the potential cost savings and new market opportunities associated with mergers. The use of a stock price that includes the value of potential mergers in conjunction with growth forecasts that do not include the growth enhancing prospects of potential mergers may distort the DCF model result.

Q. Please summarize the results of your application of the DCF model to your electric utility group.

A. As shown on Schedule 1, I obtain an average DCF result of 10.1 percent for my electric utility proxy company group.

B. CAPITAL ASSET PRICING MODEL

Q. What is the CAPM?

A. The CAPM is an equilibrium model of the security markets in which the expected or required return on a given security is equal to the risk-free rate of interest, plus the company equity "beta," times the market risk premium:

Cost of equity = Risk-free rate + Equity beta x Market risk premium

The risk-free rate in this equation is the expected rate of return on a risk-free government security, the equity beta is a measure of the company's risk relative to the market as a whole, and the market risk premium is the premium investors require to invest in the market basket of all securities compared to the risk-free security.

Q. How do you use the CAPM to estimate the cost of equity for your proxy companies?

A. The CAPM requires an estimate of the risk-free rate, the company-specific risk factor or beta, and the expected return on the market portfolio. For my estimate of the risk-free rate, I use a forecasted yield to maturity on 20-year Treasury bonds of 3.8 percent, obtained using data from Value Line and the United States

Energy Information Administration ("EIA"). For my estimate of the company-specific risk, or beta, I use both the current average 0.60 Value Line beta for the Value Line electric utilities and the 0.89 beta estimated from the relationship between the historical risk premium on utilities and the historical risk premium on the market portfolio. For my estimate of the expected risk premium on the market portfolio, I use two approaches. First, I estimate the risk premium on the market portfolio using historical risk premium data reported in the *2018 Valuation Handbook* for the years 1926 through 2017, data which are consistent with the data previously reported by Ibbotson® SBBI®. Second, I estimate the risk premium on the market portfolio from the difference between the DCF cost of equity for the S&P 500 and the forecasted yield to maturity on 20-year Treasury bonds.

Q. How do you obtain the forecasted yield to maturity on 20-year Treasury bonds?

A. I obtain the forecasted yield to maturity on 20-year Treasury bonds using data from Value Line and EIA. Value Line forecasts a yield on 10-year Treasury notes equal to 3.5 percent. The spread at January 2019 between the average yield on 10-year Treasury notes (2.71 percent) and 20-year Treasury bonds (2.89 percent) is 18 basis points. Adding 18 basis points to Value Line's 3.5 percent forecasted yield on 10-year Treasury notes produces a forecasted yield of 3.68 percent for 20-year Treasury bonds (see Value Line Investment Survey, Selection & Opinion, November 30, 2018). EIA forecasts a yield of 3.73 percent on 10-year Treasury notes. Adding the 18 basis point spread between 10-year Treasury notes and 20-

year Treasury bonds to the EIA forecast of 3.73 percent for 10-year Treasury notes produces an EIA forecast for 20-year Treasury bonds equal to 3.9 percent. The average of the forecasts is 3.8 percent (3.7 percent using Value Line data and 3.9 percent using EIA data).

1. Historical CAPM

Q. How do you estimate the expected risk premium on the market portfolio using historical risk premium data developed by Ibbotson® SBBI®?

A. I estimate the expected risk premium on the market portfolio by calculating the difference between the arithmetic mean total return on the S&P 500 from 1926 to 2018 (12.06 percent) and the average income return on 20-year U.S. Treasury bonds over the same period (4.99 percent). Thus, my historical risk premium method produces a risk premium of 7.07 percent (12.06 – 4.99 = 7.07).

Q. Why do you recommend that the risk premium on the market portfolio be estimated using the arithmetic mean return on the S&P 500?

A. I recommend that the risk premium on the market portfolio be estimated using the arithmetic mean return on the S&P 500 because, for an investment which has an uncertain outcome, the arithmetic mean is the best historically-based measure of the return investors expect to receive in the future. A discussion of the importance of using arithmetic mean returns in the context of CAPM or risk premium studies is contained in Schedule 2.

Q. Why do you recommend that the risk premium on the market portfolio be measured using the income return on 20-year Treasury bonds rather than the total return on these bonds?

A. As discussed above, the CAPM requires an estimate of the risk-free rate of interest. When Treasury bonds are issued, the income return on the bond is risk free, but the total return, which includes both income and capital gains or losses, is not. Thus, the income return should be used in the CAPM because it is only the income return that is risk free.

Q. Is there any evidence from the finance literature that the application of the historical CAPM may underestimate the cost of equity?

A. Yes. There is substantial evidence that: (1) the historical CAPM tends to underestimate the cost of equity for companies whose equity beta is less than 1.0; and (2) the CAPM is less reliable the further the estimated beta is from 1.0.

Q. What is the evidence that the CAPM tends to underestimate the cost of equity for companies with betas less than 1.0 and is less reliable the further the estimated beta is from 1.0?

A. The original evidence that the unadjusted CAPM tends to underestimate the cost of equity for companies whose equity beta is less than 1.0 and is less reliable the further the estimated beta is from 1.0 was presented in a paper by Black, Jensen, and Scholes, "The Capital Asset Pricing Model: Some Empirical Tests." Numerous subsequent papers have validated the Black, Jensen, and Scholes findings, including those by Litzenberger and Ramaswamy (1979), Banz (1981), Fama and French (1992), Fama and French (2004), Fama and MacBeth (1973), and Jegadeesh and Titman (1993).[2]

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2 Fischer Black, Michael C. Jensen, and Myron Scholes, "The Capital Asset Pricing Model: Some Empirical Tests," in *Studies in the Theory of Capital Markets*, M. Jensen, Ed. New York: Praeger, 1972; Eugene Fama and James MacBeth, "Risk, Return, and Equilibrium: Empirical Tests," *Journal of Political Economy* 81 (1973), pp. 607-36; Robert Litzenberger and Krishna Ramaswamy, "The Effect of Personal Taxes and

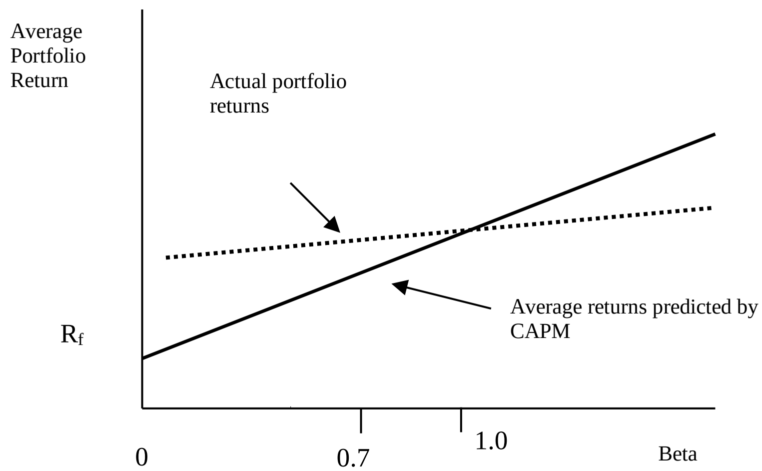
Q. Can you briefly summarize these articles?

A. Yes. The CAPM conjectures that security returns increase with increases in security betas in line with the equation:

$$ER_i = R_f + \beta_i \left\lfloor ER_m - R_f \right\rfloor,$$

where ER_i is the expected return on security or portfolio *i*, R_f is the risk-free rate, $ER_m - R_f$ is the expected risk premium on the market portfolio, and β_i is a measure of the risk of investing in security or portfolio *i* (see Figure 1 below).

FIGURE 1
AVERAGE RETURNS COMPARED TO BETA
FOR PORTFOLIOS FORMED ON PRIOR BETA



Financial scholars have studied the relationship between estimated portfolio betas and the achieved returns on the underlying portfolio of securities to test whether the CAPM correctly predicts achieved returns in the marketplace. They find that

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Dividends on Capital Asset Prices: Theory and Empirical Evidence," *Journal of Financial Economics* 7 (1979), pp. 163-95.; Rolf Banz, "The Relationship between Return and Market Value of Common Stocks," *Journal of Financial Economics* (March 1981), pp. 3-18; Eugene F. Fama and Kenneth R. French, "The Cross-Section of Expected Returns," *Journal of Finance* (June 1992), 47:2, pp. 427-465; Eugene F. Fama and Kenneth R. French, "The Capital Asset Pricing Model: Theory and Evidence," *The Journal of Economic Perspectives* (Summer 2004), 18:3, pp. 25 – 46; Narasimhan Jegadeesh and Sheridan Titman, "Returns to Buying Winners and Selling Losers: Implications for Stock Market Efficiency," *The Journal of Finance*, Vol. 48, No. 1. (Mar., 1993), pp. 65-91.

the relationship between returns and betas is inconsistent with the relationship posited by the CAPM. As described in Fama and French (1992) and Fama and French (2004), the actual relationship between portfolio betas and returns is shown by the dotted line in Figure 1 above. Although financial scholars disagree on the reasons why the return/beta relationship looks more like the dotted line in Figure 1 than the solid line, they generally agree that the dotted line lies above the solid line for portfolios with betas less than 1.0 and below the straight line for portfolios with betas greater than 1.0. Thus, in practice, scholars generally agree that the CAPM underestimates portfolio returns for companies with betas less than 1.0, and overestimates portfolio returns for portfolios with betas greater than 1.0.

Q. Do you have additional evidence that the CAPM tends to underestimate the cost of equity for utilities with average betas less than 1.0?

A. Yes. As shown in Schedule 3, over the period 1937 to 2019, investors in the S&P Utilities Stock Index have earned a risk premium over the yield on long-term Treasury bonds equal to 5.46 percent, while investors in the S&P 500 have earned a risk premium over the yield on long-term Treasury bonds equal to 6.11 percent. According to the CAPM, investors in utility stocks should expect to earn a risk premium over the yield on long-term Treasury securities equal to the average utility beta times the expected risk premium on the S&P 500. Thus, the ratio of the risk premium on the utility portfolio to the risk premium on the S&P 500 should equal the utility beta. However, the average utility beta at the time of my studies is approximately 0.60, whereas the historical ratio of the utility risk premium to the S&P 500 risk premium is 0.89 (5.46 ÷ 6.11 = 0.89). In short, the current 0.60 measured beta for electric utilities significantly underestimates the cost of equity for the utilities, providing further support for the conclusion that the CAPM underestimates the cost of equity for utilities at this time.

Q. Can you adjust for the tendency of the CAPM to underestimate the cost of equity for companies with betas significantly less than 1.0?

A. Yes. I can implement the CAPM using the 0.89 beta I discuss above, which I obtain by comparing the historical returns on utilities to historical returns on the S&P 500.

Q. What CAPM result do you obtain when you estimate the expected risk premium on the market portfolio from the arithmetic mean difference between the return on the market and the yield on 20-year Treasury bonds?

A. Using a risk-free rate equal to 3.8 percent, an electric utility beta equal to 0.60, a risk premium on the market portfolio equal to 7.1 percent, and a flotation cost allowance equal to 20 basis points, I obtain an historical CAPM estimate of the cost of equity equal to 8.2 percent for my electric utility group [3.8 + (0.60 x 7.1) + 0.20 = 8.2] (see Schedule 4). (I determine the flotation cost allowance by calculating the difference in my DCF results with and without a flotation cost allowance.)

Q. What CAPM result do you obtain when you use a beta equal to 0.89 rather than an electric utility beta equal to 0.60?

A. I obtain a CAPM result equal to 10.3 percent using a risk free rate equal to 3.8 percent, a beta equal to 0.89, the historical market risk premium equal to

7.1 percent, and a flotation cost allowance of 20 basis points (3.8 + 0.89 x 7.1+ 0.20= 10.3). (*See* Schedule 4.)

Q. What is the average of your two historical CAPM results?

A. The average of my two historical CAPM results is 9.3 percent ((8.2 percent + 10.3 percent) ÷ 2 = 9.3 percent). I conservatively use 9.3 percent as my estimate of the historical CAPM cost of equity, even though there is strong evidence justifying the use of the 10.3 percent CAPM model result, which is based on the adjusted utility beta.

2. DCF-Based CAPM

Q. How does your DCF-Based CAPM differ from your historical CAPM?

A. As noted above, my DCF-based CAPM differs from my historical CAPM only in the method I use to estimate the risk premium on the market portfolio. In the historical CAPM, I use historical risk premium data to estimate the risk premium on the market portfolio. In the DCF-based CAPM, I estimate the risk premium on the market portfolio from the difference between the DCF cost of equity for the S&P 500 and the forecasted yield to maturity on 20-year Treasury bonds.

Q. What risk premium do you obtain when you estimate the risk premium by calculating the difference between the expected return on the market (the DCF estimate for the S&P 500) and the risk-free rate?

A. Using this method, I obtain a risk premium on the market portfolio equal to 10.4 percent (14.2 percent DCF for the S&P 500) – 3.8 percent (risk-free rate) = 10.4) (see Schedule 5).

Q. What CAPM result do you obtain when you estimate the expected return on the market portfolio by applying the DCF model to the S&P 500?

A. Using a risk-free rate of 3.8 percent, an electric utility beta of 0.60, a risk premium on the market portfolio of 10.4 percent, and a flotation cost allowance of 20 basis points, I obtain a CAPM result of 10.2 percent for my electric utility group. Using a risk-free rate of 3.8 percent, an electric utility beta of 0.89, a risk premium on the market portfolio of 10.4 percent, and a flotation cost allowance of 20 basis points, I obtain a CAPM result of 13.3 percent for my electric utility group. The average of my two DCF-based CAPM results is 11.7 percent ((10.2 percent + 13.3 percent) ÷ 2 = 11.7 percent). I use 11.7 percent as my estimate of the DCF-based CAPM cost of equity.

C. COMPARABLE EARNINGS METHOD

Q. What is the comparable earnings method for estimating the required rate of return on equity?

A. The comparable earnings method estimates the required rate of return on equity by calculating the expected rate of return on book equity for a group of comparable risk companies. The United States Supreme Court states in the *Hope Natural Gas* case that the "return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks." [*Federal Power Comm'n v. Hope Natural Gas Co.,* 320 U.S. 591, 603 (1944).] The comparable earnings approach implements the *Hope* standard by calculating the expected rate of return on book equity for a group of comparable-risk companies.

Q. What comparable risk companies do you use to estimate RECO's required rate of return on equity using the comparable earnings method?

A. I use all the investment-grade Value Line electric utilities with sufficient data to estimate RECO's cost of equity using the comparable earnings method.

Q. How do you calculate the expected rate of return on book equity for these comparable-risk electric utilities?

A. I compute the expected rate of return on book equity for these comparable-risk utilities by calculating the average expected rate of return on book equity reported by The Value Line Investment Survey for the years 2018, 2019, and 2022 – 2024.

Q. Do you make any adjustments to Value Line's reported expected rates of return on book equity?

A. Yes. Value Line calculates its expected rates of return on book equity by dividing each company's expected earnings by its estimate of the company's year-end equity. Because a rate of return based on year-end equity understates the rate of return on the average equity investment during the year, I adjust Value Line's estimates to reflect expected rates of return on average equity for the year. My method for calculating the expected rate of return on average book equity for the comparable companies is described in the notes accompanying my exhibit.

Q. What average expected rate of return on book equity do you obtain for your group of comparable-risk utilities?

A. The average expected rate of return on book equity for this large group of comparable-risk utilities is 10.7 percent (see Schedule 6).

V. RECOMMENDED RATE OF RETURN ON EQUITY

Q. Based on the results of your DCF, CAPM, and comparable earnings analyses, what is your recommended allowed rate of return on equity for RECO?

A. Based on the results of my DCF, CAPM, and comparable earnings analyses, I recommend that RECO be allowed to earn a rate of return on equity equal to 10.4 percent.

Q. How do you arrive at your recommended 10.4 percent allowed rate of return on equity for RECO?

A. I arrive at my recommended 10.4 percent allowed rate of return on equity for RECO by giving a one-third weight to the results of my DCF analysis, a one-third weight to the average result of my CAPM analyses, and a one-third weight to the result of my comparable earnings analysis (see TABLE 1 below).

TABLE 1
COST OF EQUITY MODEL RESULTS

METHOD	MODEL RESULT	WEIGHT	WEIGHTED RESULT
DCF	10.1%	33%	3.37%
CAPM – Historical	9.3%		
CAPM – DCF-based	11.7%		
Average CAPM	10.5%	33%	3.50%
Comparable Earnings	10.7%	33%	3.57%
Average	10.4%		

VI. TESTS OF REASONABLENESS

Q. Do you conduct any tests of the reasonableness of your recommended 10.4 percent allowed return on equity for RECO?

A. Yes. To test the reasonableness of my recommended 10.4 percent allowed return on equity for RECO, I also examine the expected rate of return on book equity for a group of low-risk industrial companies and estimate RECO's cost of equity using two versions of the risk premium approach.

A. EXPECTED RATE OF RETURN ON BOOK EQUITY FOR GROUP OF LOW-RISK INDUSTRIAL COMPANIES

Q. Why do you test the reasonableness of your cost of equity recommendation by calculating the average Value Line expected return on book equity for a group of low-risk industrial companies?

A. I test the reasonableness of my cost of equity recommendation by calculating the average Value Line expected return on book equity for a group of low-risk industrial companies because, as I discuss above, the United States Supreme Court found in the *Hope* case that "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks." [*Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944)*.]

Q. How do you select the group of low-risk industrial companies you use to test the reasonableness of your 10.4 percent cost of equity estimate in this proceeding?

A. Beginning with the Value Line universe of more than 5,000 publicly-traded companies, I select all industrial companies in the Value Line universe of companies that pay dividends, have a Safety Rank of 1, a beta in the range .50 to .70, and Financial Strength equal to or greater than A. The average ratings for the identified group of low-risk industrials are Safety Rank, 1; beta, .68; and

Financial Strength, A+. I note that only eight companies meet this low-risk selection criteria.

Q. What is the average expected rate of return on book equity for your group of low-risk industrial companies?

A. The average expected rate of return on book equity for the identified group of low-risk industrial companies is 17.5 percent, excluding two high-end outlier results (see Schedule 7).

B. RISK PREMIUM ANALYSIS

Q. Please describe the risk premium method of estimating the cost of equity.

A. The risk premium method is based on the principle that investors expect to earn a return on an equity investment that reflects a "premium" over the interest rate they expect to earn on an investment in bonds. This equity risk premium compensates equity investors for the additional risk they bear in making equity investments versus bond investments.

Q. Does the risk premium approach specify what debt instrument should be used to estimate the interest rate component in the methodology?

A. No. The risk premium approach can be implemented using virtually any debt instrument. However, the risk premium approach does require that the debt instrument used to estimate the risk premium be the same as the debt instrument used to calculate the interest rate component of the risk premium approach. For example, if the risk premium on equity is calculated by comparing the returns on stocks to the interest rate on A-rated utility bonds, then the interest rate on A-rated utility bonds must be used to estimate the interest rate component of the risk premium approach.

Q. Does the risk premium approach require that the same companies be used to estimate the stock return as are used to estimate the bond return?

A. No. For example, many analysts apply the risk premium approach by comparing the return on a portfolio of stocks to the income return on Treasury securities such as long-term Treasury bonds. In this widely accepted application of the risk premium approach, the same companies are not used to estimate the stock return as are used to estimate the bond return, because the United States government is not a company.

Q. How do you measure the required risk premium on an equity investment in your group of publicly-traded electric utilities?

A. I use two methods to estimate the required risk premium on an equity investment in electric utilities. The first is called the *ex ante* risk premium method and the second is called the *ex post* risk premium method.

1. *Ex Ante* Risk Premium Method

Q. Please describe your *ex ante* risk premium approach for measuring the required risk premium on an equity investment in electric utilities.

A. My *ex ante* risk premium method is based on studies of the DCF expected return on a group of electric utilities compared to the interest rate on Moody's A-rated utility bonds. Specifically, for each month in my study period, I calculate the risk premium using the equation,

$$RP_{PROXY} = DCF_{PROXY} - I_A$$

where:

RP_{PROXY} = the required risk premium on an equity investment in the proxy group of companies,

DCF_{PROXY} = average DCF estimated cost of equity on a portfolio of proxy companies; and

I_A = the yield to maturity on an investment in A-rated utility bonds.

I then perform a regression analysis to determine if there is a relationship between the calculated risk premium and the yield to maturity on utility bonds. Finally, I use the results of the regression analysis to estimate the investors' required risk premium. To estimate the cost of equity, I then add the required risk premium to the forecasted yield to maturity on A-rated utility bonds. As noted above, one could use the yield to maturity on other debt investments to measure the interest rate component of the risk premium approach as long as one uses the yield on the same debt investment to measure the expected risk premium component of the risk premium approach. I choose to use the yield on A-rated utility bonds because it is a frequently-used benchmark for utility bond yields. A detailed description of my *ex ante* risk premium studies is contained in Appendix 4, and the underlying DCF results and interest rates are displayed in Schedule 8.

Q. What cost of equity do you obtain from your *ex ante* risk premium method?

A. As discussed above, to estimate the cost of equity using the *ex ante* risk premium method, one may add the estimated risk premium over the yield on A-rated utility bonds to the expected yield to maturity on A-rated utility bonds. I obtain the expected yield to maturity on A-rated utility bonds, 5.4 percent, by averaging forecast data from Value Line and the EIA. For my electric utility sample, my analyses produce an estimated risk premium over the yield on A-rated utility bonds equal to 5.1 percent. Adding an estimated risk premium of 5.1 percent to the expected 5.4 percent yield to maturity on A-rated utility bonds produces a cost of equity estimate of 10.5 percent using the *ex ante* risk premium method.

Q. How do you obtain the expected yield on A-rated utility bonds?

A. As noted above, I obtain the expected yield to maturity on A-rated utility bonds, 5.4 percent, by averaging forecast data from Value Line and the EIA. Value Line Selection & Opinion (November 30, 2018) projects a AAA-rated Corporate bond yield equal to 4.5 percent. The average spread between A-rated utility bonds and Aaa-rated Corporate bonds is 42 basis points (A-rated utility, 4.35 percent, less Aaa-rated Corporate, 3.93 percent, equals 42 basis points). Adding 42 basis points to the 4.5 percent Value Line Aaa Corporate bond forecast equals a forecast yield of 4.92 percent for the A-rated utility bonds. The EIA forecasts an AA-rated utility bond yield equal to 5.71 percent. The spread between AA-rated utility and A-rated utility bonds is 17 basis points (4.35 percent less 4.18 percent). Adding 17 basis points to EIA's 5.71 percent AA-utility bond yield forecast equals a forecast yield for A-rated utility bonds equal to 5.88 percent. The average of the forecasts (4.92 percent using Value Line data and 5.88 percent using EIA data) is 5.4 percent.

Q. Why do you use an expected or forecasted yield to maturity on A-rated utility bonds rather than a current yield to maturity?

A. I use an expected or forecasted yield to maturity on A-rated utility bonds rather than a current yield to maturity because the fair rate of return standard requires that a company have an opportunity to earn its required return on its investment during the forward-looking period during which rates will be in effect. Economists project that future interest rates will be higher than current interest rates as the Federal Reserve allows interest rates to rise in order to prevent inflation. Thus, the use of forecasted interest rates is consistent with the fair rate of return standard, whereas the use of current interest rates at this time is not.

2. *Ex Post* Risk Premium Method

Q. Please describe your *ex post* risk premium method for measuring the required risk premium on an equity investment in electric utilities.

A. I first perform a study of the comparable returns received by bond and stock investors over the 82 years of my study. I estimate the returns on stock and bond portfolios, using stock price and dividend yield data on the S&P 500 and bond yield data on Moody's A-rated Utility Bonds. My study consists of making an investment of one dollar in the S&P 500 and Moody's A-rated utility bonds at the beginning of 1937, and reinvesting the principal plus return each year to 2019. The return associated with each stock portfolio is the sum of the annual dividend yield and capital gain (or loss) which accrued to this portfolio during the year(s) in which it was held. The return associated with the bond portfolio, on the other hand, is the sum of the annual coupon yield and capital gain (or loss) which accrued to the bond portfolio during the year(s) in which it was held. The resulting annual returns on the stock and bond portfolios purchased in each year between 1937 and 2019 are shown on Schedule 9. The average annual return on an investment in the S&P 500 stock portfolio is 11.21 percent, while the average annual return on an investment in the Moody's A-rated utility bond portfolio is

6.56 percent. The risk premium on the S&P 500 stock portfolio is, therefore, 4.65 percent.

I also conduct a second study using stock data on the S&P Utilities rather than the S&P 500. As shown on Schedule 10, the average annual return on the S&P Utility stock portfolio is 10.6 percent per year. Thus, the return on the S&P Utility stock portfolio exceeds the return on the Moody's A-rated utility bond portfolio by 4.0 percent (10.6 – 6.6 = 4.0).

Q. Why is it appropriate to perform your *ex post* risk premium analysis using both the S&P 500 and the S&P Utilities stock indices?

A. I perform my *ex post* risk premium analysis on both the S&P 500 and the S&P Utilities because I believe electric energy companies today face risks that are somewhere in between the historical average risk of the S&P Utilities and the S&P 500 over the years 1937 to 2019. Thus, I use the average of the two historically-based risk premiums as my estimate of the required risk premium for the Company in my *ex post* risk premium method.

Q. Would your study provide a different risk premium if you started with a different time period?

A. Yes. The risk premium results vary somewhat depending on the historical time period chosen. My policy is to use the largest set of reliable historical data. I thought it would be most meaningful to begin after the passage and implementation of the Public Utility Holding Company Act of 1935. This Act significantly changed the structure of the public utility industry. Because the Public Utility Holding Company Act of 1935 was not implemented until the beginning of 1937, I felt that numbers taken from before this date would not be comparable to those taken after. (The repeal of the 1935 Act has not materially impacted the structure of the public utility industry; thus, the Act's repeal does not have any impact on my choice of time period.)

Q. Why is it necessary to examine the yield from debt investments in order to determine the investors' required rate of return on equity capital?

A. As previously explained, investors expect to earn a return on their equity investment that exceeds currently available bond yields because the return on equity, as a residual return, is less certain than the yield on bonds; and investors must be compensated for this uncertainty. Investors' expectations concerning the amount by which the return on equity will exceed the bond yield may be influenced by historical differences in returns to bond and stock investors. Thus, we can estimate investors' expected returns from an equity investment from information about past differences between returns on stocks and bonds. In interpreting this information, investors would also recognize that risk premiums increase when interest rates are low.

Q. What conclusions do you draw from your *ex post* risk premium analyses about the required return on an equity investment in electric utilities?

A. My studies provide evidence that investors today require an equity return of at least 4.0 to 4.6 percentage points above the expected yield on A-rated utility bonds. As discussed above, the expected yield on A-rated utility bonds is 5.4 percent. Adding a 4.0 to 4.6 percentage point risk premium to a yield of 5.4 percent on A-rated utility bonds, I obtain an expected return on equity in the range 9.4 percent to 10.1 percent, with a midpoint estimate equal to 9.7 percent. Adding a 20 basis point allowance for flotation costs, I obtain an estimate of 9.9 percent as the *ex post* risk premium cost of equity.

Q. Do the results of your ex ante and ex post risk premium analyses combined with your other analyses support the 10.4 percent cost of equity model results you show in Table 1 above?

A. Yes. The average results from applying all these cost of equity models is also equal to 10.4 percent (see TABLE 2 below).

TABLE 2
COST OF EQUITY MODEL RESULTS INCLUDING RISK PREMIUM ANALYSES

METHOD	MODEL RESULT
DCF	10.1%
CAPM – Historical	9.3%
CAPM – DCF-based	11.7%
Comparable Earnings	10.7%
Ex Ante Risk Premium	10.5%
Ex Post Risk Premium	9.9%
Average	10.4%

Q. Does this conclude your direct testimony?

A. Yes, it does.

ROCKLAND ELECTRIC COMPANY
DIRECT TESTIMONY OF
YUKARI SAEGUSA

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Yukari Saegusa and my business address is 4 Irving Place, New York, NY 10003.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am Vice President and Treasurer of Consolidated Edison Company of New York, Inc. ("Con Edison"). I am also Treasurer of Orange and Rockland Utilities, Inc. ("Orange and Rockland"), which is an affiliate of Con Edison, as well as the corporate parent of Rockland Electric Company ("RECO" or the "Company").

Q. BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I graduated from the University of Pennsylvania, Wharton School in 1989 and received Bachelor of Science degree in Economics. I received an MBA from the MIT Sloan School of Management in 1995.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL BACKGROUND.

A. I joined Con Edison in March 2013. Prior to joining Con Edison, from 2004 to 2013, I was employed by Barclays as a Managing Director in Debt Capital Markets covering the US utility and energy sectors. I was employed from 1995 to 2004 by Citigroup also in Debt Capital Markets covering the US utility sector. In my roles at Barclays and Citigroup, I was broadly responsible for advising utility clients on the design and execution of debt capital-raising and liability management strategies.

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES.

A. My responsibilities include oversight of corporate liquidity, pensions, insurance, risk management and debt and equity financings for Consolidated Edison, Inc. ("CEI"), and its subsidiaries, including Con Edison, Orange and Rockland and RECO.

Q. HAVE YOU PREVIOUSLY SPONSORED TESTIMONY BEFORE THE NEW JERSEY BOARD OF PUBLIC UTILITIES ("NJBPU")?

A. Yes, I provided testimony on behalf of RECO in its last two base rate proceeding, *i.e.*, BPU Docket Nos. ER13111135 and ER16050428.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. My testimony supports the capital structure and overall weighted average cost of capital ("WACC"), also known as the overall rate of return, used to determine RECO's revenue requirements. I rely on the testimony of Company witness Vander Weide for RECO's current cost of equity capital.

CAPITALIZATION AND COST OF CAPITAL

Q. WHAT CAPITAL STRUCTURE SHOULD BE USED IN THE CALCULATION OF THE OVERALL WACC FOR RECO IN THIS PROCEEDING?

A. I recommend the use of the consolidated capitalization of Orange and Rockland in this proceeding.

Q PLEASE DESCRIBE THE CONSOLIDATED CAPITALIZATION OF ORANGE AND ROCKLAND.

A. Consolidated capitalization refers to the consolidated capital structure of Orange and Rockland and its wholly-owned utility subsidiary, RECO. The consolidated capital structure is presented in Exhibit P-4 and consists of the following Schedules:

Schedule 1 – Consolidated Capitalization and Cost Rates at March 31, 2019;

Schedule 2 – Consolidated Capitalization and Cost Rates at September 30, 2019 (Forecast);

Schedule 3 – Long-Term Debt Detail at March 31, 2019; and

Schedule 4 – Long-Term Debt Detail at September 30, 2019 (Forecast).

Q. WHAT IS THE SIGNIFICANCE OF THE MARCH 31, 2019 AND THE SEPTEMBER 30, 2019 DATES USED IN YOUR EXHIBITS?

A. In this case, RECO has used a test year that is the twelve-month period ending September 30, 2019 ("Test Year"). The end date for the Test Year is, therefore, the appropriate date of the projected capitalization, subject to known and measurable changes. The last month of historic data available for this filing is March 31, 2019 and is, therefore, the starting point for projecting RECO's capital structure.

Q. PLEASE DESCRIBE ANY PROJECTED CHANGES IN LONG-TERM DEBT AND HOW SUCH CHANGES HAVE BEEN INCORPORATED INTO YOUR FORECASTED DATA AT SEPTEMBER 30, 2019.

A. The forecasted balance of long-term debt at September 30, 2019 includes the contemplated issuance, by Orange and Rockland, of Series A 2019 debentures, $125 million, 5.20%, due September 1, 2049. The financing is contemplated to occur before the conclusion of the Test Year. The other projected change in the long-term debt balance between the historic data date (*i.e.*, March 31, 2019) and the end of the Test Year is the result of the periodic amortization of the balance of the Unamortized Debt Discount, Unamortized Debt Expenses and Unamortized Loss on Reacquired Debt.

Q. PLEASE DESCRIBE HOW YOU DEVELOPED THE COST OF LONG-TERM DEBT AND EXPLAIN THE CHANGE IN THE COST OF LONG-TERM DEBT BETWEEN THE ACTUAL HISTORIC DATA AND THE PROJECTED COST AT SEPTEMBER 30, 2019.

A. Exhibit P-4, Schedules 3 and 4, present the detailed calculation of the cost of the long-term debt at March 31, 2019 and September 30, 2019, respectively. The schedules detail each issue of long-term debt outstanding and calculate an effective annual cost for each issue, taking into consideration the original net proceeds to the Company and annual interest costs. The sum of the effective annual cost for all issues is divided by the gross amount of debt outstanding to derive the weighted average cost of long-term debt.

Q. PLEASE DESCRIBE THE DERIVATION OF THE EQUITY BALANCE AT MARCH 31, 2019 AND THE METHOD USED TO PROJECT THE EQUITY BALANCE THROUGH SEPTEMBER 30, 2019.

A. The actual equity balance at March 31, 2019, as shown on Exhibit P-4, Schedule 1, is the consolidated equity of Orange and Rockland and RECO. The equity of all non-utility subsidiaries has been eliminated, and the retained earnings balance excludes the effect of Other Comprehensive Income. The forecasted equity balance at September 30, 2019, as shown on Exhibit P-4, Schedule 2, contemplates a $35 million increase in the common stock component of common stock equity, as a result of an equity investment by CEI into Orange and Rockland and RECO. The forecasted retained earnings balance at September 30, 2019 was calculated by assuming an earned return on common equity of 10.0% and quarterly dividends of $11.75 million in March, June and September 2019.

Q. WHAT IS THE BASIS FOR YOUR USE OF A 10.0% RETURN ON EQUITY IN DEVELOPING THE FORECASTED BALANCE OF COMMON EQUITY AT SEPTEMBER 30, 2019?

A. Company witness Vander Weide presents direct testimony in this case addressing RECO's cost of equity capital. The 10.0% return on equity is based on the required equity return recommended by Company witness Vander Weide of 10.4%. The Company is proposing a return on equity lower than Company witness Vander Weide's recommendation in order to minimize the contested issues in this proceeding and to facilitate a settlement. The 10.0% return on equity was used as a means of estimating retained earnings for Orange and Rockland's consolidated results through the end of the Test Year in this case.

Q. WHAT CAPITAL STRUCTURE RESULTS FROM THE CALCULATIONS THAT YOU DESCRIBED?

A. Exhibit P-4, Schedule 1, shows the actual consolidated capital structure at March 31, 2019 of 48.64% long-term debt and 51.36% common stock equity. The projected consolidated capital structure at September 30, 2019, as shown on Exhibit P-4, Schedule 2, is 50.07% long-term debt and 49.93% common stock equity.

Q. WHY IS IT REASONABLE AND APPROPRIATE TO USE THE CONSOLIDATED CAPITAL STRUCTURE AND EQUITY RATIO OF ORANGE AND ROCKLAND TO DETERMINE THE WACC FOR RECO?

A. The use of Orange and Rockland's consolidated capital structure and equity ratio is reasonable and appropriate given the joint operations and financing by Orange and Rockland and its utility subsidiary, RECO. As such, use of a consolidated capital structure is reasonable and appropriate because it represents the actual ratios for investment of capital required to provide services to customers.

Q. IS THERE OTHER EVIDENCE SUPPORTING THE REASONABLENESS OF THE PROPOSED COMMON STOCK EQUITY RATIO IN THIS PROCEEDING?

A. Yes, the reasonableness of the use of the consolidated Orange and Rockland capital structure and equity ratio is confirmed based on a proxy group comparative analysis. The analysis (Exhibit YS-1) compares the equity ratio of comparable utility operating companies and the results demonstrate that the Company's proposed equity ratio is in line with the mean year-end 2018 equity ratio of the proxy group companies of 53.3%.

Q. MS. SAEGUSA, USING YOUR RECOMMENDED CAPITAL STRUCTURE AND COST OF LONG-TERM DEBT AND THE COMPANY'S PROPOSED COST OF EQUITY AS SUPPORTED BY COMPANY WITNESS VANDER WEIDE, WHAT OVERALL RATE OF RETURN IS REQUESTED IN THIS FILING?

A. The overall rate of return, or WACC, is 7.56% as shown on Exhibit P-4, Schedule 2.

Q. WHAT ARE THE COMPANY'S CREDIT RATINGS BY THE MAJOR RATINGS AGENCIES?

RECO has a long-term issuer rating of A- from Standard & Poor's ("S&P") and an issuer default rating of BBB+ from Fitch Ratings ("Fitch"). RECO has a Stable Outlook from S&P and Fitch. Moody's does not rate the credit of RECO. In the overall Orange and Rockland complex, RECO represents approximately 15% of Orange and Rockland's total operating income. Therefore, Orange and Rockland's credit ratings partially reflect the credit quality of RECO. Moody's long-term debt rating (senior unsecured) for Orange and Rockland is Baa1 with a Stable Outlook. S&P's long-term debt rating (senior unsecured) for Orange and Rockland is A- with a Stable Outlook. Fitch's long-term debt rating (senior unsecured) for Orange and Rockland is A- with a Stable Outlook.

Q. PLEASE EXPLAIN WHY IT IS IMPORTANT FOR ORANGE AND ROCKLAND AND RECO TO MAINTAIN THEIR CURRENT CREDIT RATINGS?

A. RECO plans to invest a significant amount of capital in its infrastructure to maintain system reliability. Strong credit ratings will enable Orange and Rockland, on behalf of RECO, to access the capital markets in all types of market conditions and achieve favorable pricing and terms from investors. The maintenance of strong credit ratings depends in large part on the determinations of state regulators to recognize appropriate equity ratios and returns on equity.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.