STATE OF NEW JERSEY
OFFICE OF ADMINISTRATIVE LAW
BEFORE THE HONORABLE IRENE JONES

IN THE MATTER OF THE VERIFIED PETITION OF ROCKLAND ELECTRIC COMPANY FOR APPROVAL OF CHANGES IN ELECTRIC RATES, ITS TARIFF FOR ELECTRIC SERVICE, AND ITS DEPRECIATION RATES, AND FOR OTHER RELIEF	**)** **)** **)** **)** **)** **)** **)**	BPU DOCKET NO. ER19050552 OAL DOCKET NO. PUC07548-2019

DIRECT TESTIMONY OF ANDREA C. CRANE ON BEHALF OF THE DIVISION OF RATE COUNSEL

STEFANIE A. BRAND, ESQ.
DIRECTOR, DIVISION OF RATE COUNSEL

DIVISION OF RATE COUNSEL
140 East Front Street, 4th Floor
P. O. Box 003
Trenton, New Jersey 08625
Phone: 609-984-1460
Email: njratepayer@rpa.nj.gov

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I. STATEMENT OF QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Andrea C. Crane and my business address is 2805 East Oakland Park Boulevard, # 401, Ft. Lauderdale, Florida 33308.

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

A. I am President of The Columbia Group, Inc., a financial consulting firm that specializes in utility regulation. In this capacity, I analyze rate filings, prepare expert testimony, and undertake various studies relating to utility rates and regulatory policy. I have held several positions of increasing responsibility since I joined The Columbia Group, Inc. in January 1989. I became President of the firm in March 2008.

Q. Please summarize your professional experience in the utility industry.

A. Prior to my association with The Columbia Group, Inc., I held the position of Economic Policy and Analysis Staff Manager for GTE Service Corporation, from December 1987 to January 1989. From June 1982 to September 1987, I was employed by various Bell Atlantic (now Verizon) subsidiaries. While at Bell Atlantic, I held assignments in the Product Management, Treasury, and Regulatory Departments.

Q. Have you previously testified in regulatory proceedings?

A. Yes, since joining The Columbia Group, Inc., I have testified in over 400 regulatory proceedings in the states of Arizona, Arkansas, Connecticut, Delaware, Hawaii, Kansas, Kentucky, Maryland, New Jersey, New Mexico, New York, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Vermont, Washington, West Virginia and the District of Columbia. These proceedings involved electric, gas, water, wastewater, telephone, solid waste, cable television, and navigation utilities. A list of dockets in which I have filed testimony in the last five years is included in Appendix A.

Q. What is your educational background?

A. I received a Master of Business Administration degree, with a concentration in Finance, from Temple University in Philadelphia, Pennsylvania. My undergraduate degree is a B.A. in Chemistry from Temple University.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. On May 3, 2019, Rockland Electric Company ("RECO" or "Company") filed a Petition with the New Jersey Board of Public Utilities ("BPU" or "Board") requesting changes in its base distribution rates for electric service. The Columbia Group, Inc. was engaged by The New Jersey Division of Rate Counsel ("Rate Counsel") to review the Company's Petition and to provide recommendations to the BPU regarding the Company's revenue requirement claims.

In developing my recommendations, I relied upon the testimony of other Rate Counsel witnesses. Specifically, I relied upon the cost of capital and capital structure testimony of Matthew I. Kahal, on the depreciation testimony of James Garren, on the testimony of Paul Alvarez regarding the Company's AMI program, and on the testimony of Charles Salamone and Maximilian Chang on certain engineering and operational issues. Testimony on behalf of Rate Counsel is also being filed by David Petersen on class cost of service/rate design issues and by Susan Baldwin on customer service issues.

Q. Please provide a brief summary of the Company's filing.

A. In its original Petition filed on May 3, 2019, RECO requested an electric base revenue increase of $19.9 million or approximately 9.6% on total revenues.[1] The Company's Petition was based on a Test Year ending September 30, 2019. As filed, the Petition reflected six months of actual data and six months of projected results. RECO's filing was based on an overall cost of capital of 7.56%, which included 49.93% common equity at a cost of 10.0%.

On July 30, 2019, the Company filed an update to its Application, which reflected actual results through June 30, 2019 and projections for the last three months of the Test Year ("9&3 Update"). The 9+3 Update reflected a revenue increase of $20.401 million. In its update, RECO made slight revisions to its proposed capital structure and cost of debt, but continued to request that the BPU authorize a 10.0% cost of equity.

1 All amounts exclude sales and use taxes ("SUT").

Q. What are the most significant issues in this rate proceeding?

A. The most significant issues driving the Company's claims in this case are 1) its request for an authorized cost of equity of 10.0%; 2) incremental investment including investment associated with its AMI Program, 3) the Company's claim for recovery of prior storm-related costs, as well as increased annual costs associated with prospective storm costs, 4) its request for increased costs relating to management of diseased trees, and 5) increases in labor costs.

III. SUMMARY OF CONCLUSIONS

Q. What are your conclusions concerning the Company's revenue requirement and its need for rate relief?

A. Based on my analysis of the Company's filing, and other documentation in this case, my conclusions are as follows:

1. The twelve months ending September 30, 2019 is a reasonable Test Year to use in this case to evaluate the reasonableness of the Company's claims.
2. Based on the testimony of Mr. Kahal, the Company has a cost of equity of 8.90% and an overall cost of capital of 6.79% (see Schedule ACC-2).[2]
3. RECO has pro forma electric distribution rate base of $196.359 million (see Schedule ACC-3).
4. The Company has pro forma electric distribution operating income at present rates of $9.151 million (see Schedule ACC-14).

[2] Schedules ACC-1 and ACC-34 are summary schedules, Schedule ACC-2 is a cost of capital schedule, Schedule ACC-3 to ACC-13 are rate base schedules, and Schedules ACC-14 to ACC-33 are operating income schedules.

5. RECO has a pro forma revenue deficiency of $5.817 million.

6. RECO's request to continue automatic deferrals for certain storm-related costs should be denied by the BPU.

7. The BPU should exclude the costs of RECO's AMI Program from its revenue requirement, based on a finding that the Company did not demonstrate that these costs were prudently-incurred, as discussed in the testimony of Mr. Alvarez. In the alternative, if the BPU decides to include the AMI investment in rate base, then the BPU should disallow stranded costs associated with the legacy meters.

8. My revenue requirement recommendation may be updated once the Company files its actual Test Year results, based on the twelve months ending September 30, 2019.

9. The BPU should not assume that I support all of the Company's underlying methodologies for those Company adjustments that are not addressed in my testimony. In some cases, I may have concerns about the underlying methodologies but I determined that the result was reasonable and therefore I am not recommending any adjustment to the Company's claim.

IV. COST OF CAPITAL AND CAPITAL STRUCTURE

Q. What is the cost of capital and capital structure that RECO is requesting in this case?

A. The Company reflected the following capital structure and cost of capital in its 9+3 Update filing:

	Percent of Total	Cost Rate	Weighted Cost
Long Term Debt	50.96%	5.134%	2.61%
Common Equity	49.04%	10.00%	4.90%
Total	100.00%		7.51%

Q. What is the capital structure and overall cost of capital that Rate Counsel is recommending for RECO?

A. As shown on Schedule MIK-1 of Mr. Kahal's testimony, Rate Counsel is recommending an overall cost of capital for RECO of 6.79% based on the following capital structure and cost rates:

	Percent of Total	Cost Rate	Weighted Cost
Long Term Debt	52.86%	4.90%	2.59%
Common Equity	47.14%	8.90%	4.20%
Total	100.00%		6.79%

Mr. Kahal is recommending a slightly different capital structure and a slightly lower cost of debt for the Company. In addition, he is recommending that the Board authorize a cost of equity of 8.9% for RECO. Mr. Kahal's adjustments result in a pro forma overall cost of capital of 6.79%, which is the overall cost of capital that I have used to determine the Company's pro forma required income, as shown on summary Schedule ACC-1, based on my recommended rate base. I then compared this required income to pro forma income at present rates to determine the Company's need for rate relief.

V. RATE BASE ISSUES

A. Utility Plant-in-Service

Q. How did RECO determine its utility plant-in-service claim in this case?

A. The Company began with its projected utility plant-in-service balance at September 30, 2019, the end of the Test Year in this case. RECO then made post-test year adjustments to reflect certain projected plant-in-service additions through March 30, 2020. The Company included $11.557 million of post-test year electric plant additions in its rate base claim, less associated post-test year retirements of $2.189 million, resulting in net post-test year additions of $9.369 million.

Q. Are you recommending any adjustments to the Company's claim for utility plant-in-service?

A. Yes, I am recommending that the BPU eliminate all post-test year plant additions from the Company's rate base.

Q. What is the basis for your recommendation to exclude all post-test year plant additions from rate base?

A. The Company's claim results in a mismatch among the components of the regulatory triad used to set rates in this case and is inconsistent with BPU precedent regarding the inclusion of post-test year plant additions in rate base. Ratesetting is based on a regulatory triad that attempts to match revenues, expenses, and rate base investment during a twelve-month test year period. In addition, while the Board has authorized certain post-test year plant adjustments in certain cases, Rate Counsel does not believe that the post-test year plant additions claimed by RECO meet the criteria outlined by the Board for such ratemaking treatment.

Q. What is your understanding of BPU policy with regard to post-test year plant additions?

A. I am aware that the New Jersey BPU has in the past permitted certain post-test year plant-in-service additions to be included in rate base. As stated in the Board's Decision on Motion for Determination of Test Year and Appropriate Time Period for Adjustments, Elizabethtown Water Company, Docket No. WR8504330, page 2 ("Elizabethtown Order"):

> With regard to the second issue, that is, the appropriate time period and standard to apply to out-of-period adjustments, the standard that shall be applied and shall govern petitioner's filing and proofs is that which the Board has consistently applied, the "known and measurable" standard. Known and measurable changes to the test year must be (1) prudent and major in nature and consequence, (2) carefully quantified through proofs which (3) manifest convincingly reliable data. The Board recognizes that known and measurable changes to the test year, by definition, reflect future contingencies; but in order to prevail, petitioner must quantify such adjustments by reliable forecasting techniques reflected in the record.

It is clear that the Company has not met the criteria specified by the BPU for the inclusion of post-test year projects in rate base. RECO has not limited its post-test year plant-in-service claim to projects that are "major in nature and consequence." Instead, the Company has included routine projects scheduled to be completed by March 30, 2020 and more than half of the projects included by RECO are blanket projects. The specific capital projected requested by RECO are further addressed in the testimony of Mr. Salamone and Mr. Chang.

Q. What do you recommend?

A. Since RECO has not demonstrated that its post-test year projects meet the requirements laid out in the Elizabethtown decision, I recommend that all post-test year plant additions be eliminated from the Company's claim. Therefore, my revenue requirement recommendation reflects the Company's projected September 30, 2019 utility plant-in-service balances, as claimed in the 9&3 Update. My adjustment is shown in Schedule ACC-4.

Q. Did you make corresponding adjustments associated with retirements, accumulated depreciation and accumulated deferred income taxes?

A. Yes, I did. Since I have eliminated post-test year plant additions from the Company's rate base, it is necessary to make corresponding adjustments to remove the post-test year adjustments related to retirements, accumulated depreciation and accumulated deferred income taxes. Since my recommendation is based on plant balances at September 30, 2019, the adjustments shown in Schedule ACC-4 include the impact of removing post-test year plant retirements. In addition, I have reflected the associated adjustment relating to the depreciation reserve in Schedule ACC-8 and the associated adjustment relating to the accumulated deferred income tax reserve in Schedule ACC-12. All of these adjustments are carried over to my Rate Base Summary, Schedule ACC-3.

B. AMI Program Investment

Q. Please describe the Company's rate base claim associated with the AMI Program.

A. In its rate base claim, the Company included investment associated with its AMI Program. The Company began replacing its existing meters ("legacy meters") with AMI meters in May 2018. In its filing, RECO is requesting authorization to charge ratepayers a return on and of the new AMI meters. In addition, the Company is proposing to recover the stranded costs of the legacy meters by amortizing the unrecovered balance of the legacy meters over 15 years, and including the unamortized balance in rate base. While the Company proposes to transfer the legacy meters from its plant-in-service accounts to a regulatory asset, and is seeking rate base treatment for that regulatory asset, the legacy meters are still included in plant-in-service in the Company's filing, along with the AMI meters.

Q. Are you recommending any adjustment to the Company's claim?

A. Yes, I am recommending several adjustments, based on the testimony of Rate Counsel witness Paul Alvarez. Mr. Alvarez concluded that the Company has not demonstrated that the AMI program results in net benefits for ratepayers. Therefore, at this time I am recommending that the incremental costs of the AMI Program be eliminated from the Company's revenue requirement claim. Mr. Alvarez's recommendation, and my revenue requirement recommendation, may be updated based on a report on the AMI Program that is being developed by BPU Staff, in conjunction with an outside consultant. Once we review the results of that report, Mr. Alvarez and I will update our recommendations, if necessary and appropriate. In the interim, I have eliminated the incremental AMI costs from my recommended revenue increase. My adjustments to plant-in-service, accumulated depreciation, and the deferred income tax reserve are shown in Schedule 5, and are incorporated in my Rate Base Summary, Schedule ACC-3.

Q. How did you quantify your adjustment?

A. With regard to the Company's rate base claim, I eliminated the plant-in-service, accumulated depreciation, and accumulated deferred income taxes associated with the AMI Program. Since the legacy meters are already included in rate base, no further adjustment to the legacy meters was necessary. In addition to rate base adjustments, I also made several operating income adjustments, as discussed later in my testimony.

C. <u>Plant Held For Future Use</u>

Q. Has the Company included any plant held for future use in rate base?

A. Yes, the Company has included $209,000 of plant held for future use in its rate base claim.

Q. What is plant held for future use?

A. Plant held for future use is plant that is not currently used in the provision of utility service to customers but which the Company claims has some potential to be used in the future to serve customers. As described in the response to S-RECO-REV-40, the plant held for future use that the Company included in rate base consists of land for future substation sites. None of this plant is expected to be in-service prior to 2026.

Q. Have you included plant held for future use in your revenue requirement recommendation?

A. No, I have not. This plant is, by definition, not used and useful in providing utility service to current customers. Moreover, this plant may never be used in the provision of utility service. Including this plant in rate base is speculative until such time as the plant is actually in-service and used and useful in the provision of utility service. In any case, this plant was not in-service at September 30, 2019, the end of the Test Year in this case. Nor is any of this plant anticipated to be in-service by March 31, 2020, six months after the end of the Test Year. Accordingly, I am recommending that all plant held for future use be eliminated from the Company's rate base claim in this case. My adjustment is shown in Schedule ACC-6.

D. <u>Construction Work in Progress</u>

Q. What is CWIP?

A. CWIP is plant that is under construction but which has not yet been completed and placed into service. Once the plant is completed and serving customers, then the plant is booked to utility plant-in-service and the utility begins to take depreciation expense on the plant.

Q. How did RECO develop its claim for CWIP in this case?

A. RECO included in rate base all of its estimated, non-interest bearing CWIP as of the end of the Test Year. The Company claims that this CWIP is generally completed within the month, which is why it does not accrue an allowance for funds used during construction ("AFUDC").

Q. Do you believe that CWIP is an appropriate rate base element?

A. No, I do not believe that CWIP is an appropriate rate base element. CWIP does not represent facilities that are used or useful in the provision of utility service. In addition, including this plant in rate base violates the regulatory principle of intergenerational equity by requiring current ratepayers to pay a return on plant that is not providing them with utility service and which may never provide current ratepayers with utility service.

In addition, it is my understanding that the BPU generally disallows CWIP from rate base, unless it meets the post-test year, plant-in-service parameters of the Elizabethtown Decision, discussed previously. Since this plant clearly is not major in nature and consequence, it does not quality for inclusion in rate base under the Elizabethtown standard. Therefore, at Schedule ACC-7, I have made an adjustment to exclude this CWIP from the Company's revenue requirement.

E. Cash Working Capital

Q. What is cash working capital?

A. Cash working capital is the amount of cash that is required by a utility in order to cover cash outflows between the time that revenues are received from customers and the time that expenses must be paid. For example, assume that a utility bills its customers monthly and that it receives monthly revenues approximately 30 days after the midpoint of the date that service is provided. If the Company pays its employees weekly, it will have a need for cash prior to receiving the monthly revenue stream. If, on the other hand, the Company pays its interest expense semi-annually, it will receive these revenues well in advance of needing the funds to pay interest expense.

Q. Do utilities always have a positive cash working capital requirement?

A. No, they do not. The actual amount and timing of cash flows dictate whether or not a utility requires a cash working capital allowance. Therefore, one should examine actual cash flows through a lead/lag study in order to accurately measure a utility's need for cash working capital.

Q. Please describe the Company's claim for cash working capital.

A. RECO developed a proposed cash working capital allowance based on the results of its lead-lag study. The resulting lead-lag days were applied to the Company's proposed revenue requirement in order to determine its cash working capital requirement.

Q. Are you recommending any adjustments to the Company's cash working capital claim?

A. Yes, I am recommending several adjustments to the expense components included in the Company's lead-lag study. In addition, I am recommending an adjustment to the formula used by the Company to develop its requested cash working capital allowance.

Q. Please discuss your recommended adjustments to the expense components included in the Company's lead-lag study.

A. I recommend that RECO's cash working capital claim be revised to eliminate cash working capital associated with non-cash items, such as uncollectible costs, depreciation and amortization expense and deferred taxes. Moreover, I recommend that non-contractual costs, such as utility operating income, be excluded from the lead-lag study. Finally, I recommend that the lead-lag study be revised to include the lag on interest expense.

Q. Please explain how RECO has treated the non-cash items you have eliminated in your adjustments to cash working capital.

A. RECO has included depreciation and amortization expenses, deferred income taxes and operating income in the lead-lag calculation as expenses with zero-lag days. The inclusion of these items with a zero lag has a very significant impact on the cash working capital requirement because it assumes that the Company has a continuous need for cash to meet these costs and that this cash is required at the same time that utility service is provided, i.e., there is no lag.

With regard to uncollectible costs, RECO included these costs in its cash working capital claim with an expense lag of 40.4 days, which is equal to its proposed revenue lag.

Q. What is the basis for your recommendation to exclude depreciation and amortization expense entirely from the lead-lag study?

A. It is inappropriate to include depreciation and amortization expense in a utility's cash working capital claim because these costs do not result in cash outflows by the utility. RECO does not make cash payments for depreciation or amortization expenses on a specified date. The purpose of a lead-lag study is to match cash inflows, or revenues, with cash outflows, or expenses. Cash working capital reflects the need for investor-supplied funds to meet the day-to-day expenses of operations that arise from the timing differences between when RECO has to expend money to pay the expenses of operation and when revenues for utility service are received by the utility. Only items for which actual out-of-pocket cash expenditures are required should be included in a cash working capital allowance. Therefore, I have made adjustments to eliminate the cash working capital claims associated with depreciation and amortization expense from RECO's cash working capital claim.

Q. Why do you also reject the use of zero lag days for deferred tax expense?

A. This item is similar to depreciation expense in that deferred income taxes are, by definition, deferred and therefore they do not create a need for cash. Therefore, deferred tax expense is not properly includable in any form in the calculation of cash working capital. My recommendation to exclude uncollectible costs from the Company's cash working capital allowance was similarly based on the fact that these costs do not result in a cash outlay by the utility.

Q. Please explain why you have rejected the Company's claim for zero lag days for operating income.

A. Operating income includes a cost of equity component as well as a cost of debt. The cost of debt component, i.e., interest expense, is addressed below. That component of invested capital has a lag of 91.25 days, assuming semi-annual interest payments, not the zero lag included in the Company's lead/lag study.

With regard to the cost of equity, this does not represent a contractual obligation of RECO. The Company is under no obligation to make payments to its stockholders. While RECO may make dividend payments, they are not contractually obligated to do so. Moreover, even if dividend payments are made, they are generally made no more frequently than quarterly. They are certainly not made on a daily basis, which is the assumption inherent in the use of a zero lag. In addition, companies generally retain a portion of their earnings rather than paying out all earnings as dividends, another fact not taken into account in the Company's study. Therefore, it is inappropriate to reflect a zero lag, and to correspondingly increase the Company's cash working capital, for the return on equity.

Q. Has RECO reflected a reduction in cash working capital related to the lag in its payment of interest expense?

A. No, it has not. The Company has failed to reflect the fact that the revenue requirement includes a component for interest expense, which is a contractual cash obligation of the utility.

Q. How is working capital generated by the Company's lag in the payment of its interest expense?

A. RECO collects revenues from ratepayers for interest expense on a monthly basis but pays its bondholders for interest only twice a year. Therefore, on average, the accrued interest funds are available to the Company, at no cost, to finance their operations between the time they collect the interest from customers and the time that interest payments are made to bondholders.

Q. How should this cost-free source of funds be reflected for ratemaking purposes?

A. The lag in the payment of interest expense must be reflected in the cash working capital calculation so that ratepayers are compensated for providing a cost-free source of capital to RECO prior to the interest payments being made. In developing my adjustment, I included the interest expense at a lag of 91.25 days, which reflects semi-annual payments of interest.[3]

Q. Are you recommending any other adjustments to the Company's lead-lag study?

A. Yes, I am recommending an additional adjustment to the formula used by the Company in its lead lag study. As shown on Exhibit P-3, Schedule 6, page 2, RECO calculated the revenue lag days, expense lag days, and net lag days, but the Company did not actually use the net lag days in order to calculate its cash working capital allowance. After calculating the net lag days, RECO should have determined the daily distribution cost of service requirement by

3 Reflects the lag from the midpoint of the 182.5-day service period (365 / 2 / 2).

dividing the Distribution Amount of $154,653,849 by 365 ($423,709 per day). It should then have multiplied the net lag days of 16.0 days by the daily lag of $423,709 to determine the cash working capital allowance. Instead, RECO subtracted the Distribution Dollar Days associated with its expenses from the Distribution Dollar Days associated with revenues, in order to determine the Distribution Dollars Days Net Lag, and then divided that result by 365 days to obtain its cash working capital allowance.

Q. What are the problems with the methodology used by the Company?

A. The methodology used by the Company has two main problems. First, it assumes that all Distribution Dollar Day revenues that exceed the Distribution Dollar Day expenses are actually required to meet the cash working capital needs of the utility. This assumption ignores the fact that many revenues are not required to meet the utility's cash needs, as stated above. A second, and related, issue is that eliminating non-cash cost of service components that have a zero lag from the Company's study will not change the cash working capital requirement if the Company's methodology is used – regardless of the amount of non-cash items that are included at a zero lag, the cash working capital requirement stays the same.

Q. What do you recommend?

A. I have modified the Company's model to first calculate a daily cash requirement and then multiplied that daily requirement by the net lag days. This adjustment does not significantly change the cash working capital allowance using the components included by the Company in its filing. However, it does have a significant impact once we eliminate certain non-cash components as discussed above.

Q. What is the impact of your recommended cash working capital adjustments?

A. My recommended adjustments reduce the Company's cash working capital allowance from $6.783 million reflected in the 9+3 Update to $3.564 million, as shown in Schedule ACC-9.

Q. Do you have any additional comments regarding cash working capital?

A. Yes. I have not attempted to reflect the impact of my recommended expense adjustments in my pro forma cash working capital recommendation. However, I recommend that the cash working capital requirement be updated to reflect the actual level of expenses, including interest expense, found by the BPU to be appropriate.

F. <u>Deferred Regulatory Balances</u>

Q. Please describe the deferred regulatory balances included by RECO in its rate base claim.

A. RECO included $550,000 of deferred regulatory balances in its rate base claim. As shown on Exhibit P-3, Schedule 7 of the 9+3 Update, the Company included three regulatory assets: Deferred Management Audit costs of $471,000, Deferred Rate Case costs of $22,000 relating to the previous rate case, and Deferred Rate Case costs of $431,000 relating to the current proceeding. In addition, RECO included a regulatory liability of $6,000 relating to expiring amortizations authorized in the last rate case and a regulatory liability of $369,000 relating to excess deferred income taxes ("EDIT").

Q. Have you included these Deferred Regulatory Balances in your rate base recommendation?

A. I have excluded these deferred regulatory balances from my rate base recommendation, except for the regulatory liability associated with EDIT. The treatment of the EDIT that resulted from the Tax Cut and Jobs Act of 2017 ("TCJA") has already been addressed by the BPU.

Q. Why do you recommend that the remaining regulatory assets and liabilities be excluded from rate base?

A. The rate case cost deferral relating to the previous rate case and the regulatory liability relating to other amortizations authorized in the last case will be fully amortized by the time that new rates are established in this case. These deferrals were authorized to be recovered over a three-year period beginning March 1, 2017. Therefore, these deferrals will have expired prior to the effective date of new rates.

In addition, while the parties in the last RECO case agreed to permit the Company to amortize a total of $225,000 in rate case costs, it is my experience that rate case costs are generally normalized, not amortized, for ratemaking purposes in New Jersey. Amortization is, by definition, retroactive ratemaking since it involves recovery of a previously-incurred cost in future rates. Normalization, however, is prospective and reflects the recovery of a normal level of prospective annual costs. With normalization, by definition there is no unamortized balance and therefore a request for carrying charges is inconsistent with the normalization approach.

Finally, even if costs are amortized instead of normalized, there is still no requirement that the unamortized balance be included in rate base. Allowing a utility to recover previously incurred costs in future rates through an amortization provides a significant benefit to shareholders. Recovery of that cost should not be turned into a profit center by allowing the utility to include the unamortized balance in rate base. Therefore, I have also eliminated the unamortized balance of Deferred Management Audit costs from the Company's rate base. My adjustments relating to the Company's claim for Deferred Regulatory Balances are shown in Schedule ACC-10.

G. Storm Reserves

Q. How did the Company develop its claim associated with storm damage costs in this case?

A. RECO's claim has three components. First, the Company included a storm reserve of $9.538 million in its rate base claim. Second, it is seeking recovery of $13.267 million for costs incurred in prior storms. Third, it is seeking an increase in the annual funding of the storm damage reserve from $750,000 to $1,478,254.

Q. Are you recommending any adjustments to the Company's claim?

A. Yes, I am recommending several adjustments. With regard to rate base costs, I am recommending that the Company's request to include a storm damage reserve in rate base be disallowed. I am also recommending an adjustment to the Company's expense claims for annual recovery of major storms, as well as an adjustment to its claim for recovery of previously-incurred extraordinary storm costs, as discussed later in the Operating Income section of my testimony.

Q. What is the basis for your recommendation to exclude unamortized storm damage costs from rate base?

A. RECO's filing is based on an assumption that the Company has been guaranteed recovery of all storm damage costs on a dollar for dollar basis, along with carrying costs at the weighted average cost of capital. However, this is not the case. In its last base rate case, RECO was authorized to collect certain costs associated with previous storms and to include funding for a storm reserve in annual rates. However, the costs that were the subject of the storm cost amortization in the prior case were considered "extraordinary storm damage costs" as stated in the Stipulation in BPU Docket No. ER16050428. In addition, that stipulation required RECO to reduce its rates when the amortization of those costs ended on July 31, 2018. The stipulation also provided that annual rates would include funding for a storm damage reserve of $750,000. However, there was no agreement that costs exceeding this annual level would be eligible for future recovery, or that the deferred storm damage reserve would be included in base rates in all future rate proceedings.

RECO's investors should not be permitted to earn a "profit" on storm damage costs by including unamortized costs in rate base. Shareholders are awarded a risk-adjusted return on equity because they are expected to incur some risk. Allowing shareholders to amortize all prior storm damage costs, and to earn a return on the unamortized balance, eliminates all such risk for shareholders and instead transfers it to the Company's regulated ratepayers. Allowing the Company to recover some prior storm damage costs, as discussed below, while denying the Company's claim to include the unamortized balance in rate base provides a good balance between ratepayers and shareholders. Therefore, I recommend that the BPU reject the Company's claim to include unamortized storm damage costs in rate base. My adjustment to rate base is shown in Schedule ACC-11.

H. <u>Consolidated Income Taxes</u>

Q. **Does RECO file its income taxes as part of a consolidated income tax group?**

A. Yes, it does. RECO files its income taxes as part of a consolidated income tax group that included the holding company, Consolidated Edison, Inc. ("ConEd") and all of its subsidiaries. By filing a consolidated return, the tax loss benefits generated by one group member can be shared by the other consolidated group members, resulting in a reduction in the effective federal income tax rate.

Q. Has the BPU traditionally flowed through the benefits of filing a consolidated income tax return to New Jersey ratepayers?

A. Yes, it has. The BPU has traditionally flowed these benefits through to ratepayers. The issue of consolidated income tax adjustments has been thoroughly reviewed by both the Board and the New Jersey courts, both of whom have found that a consolidated income tax adjustment is appropriate.[4] In its Decision in the 1991 Jersey Central Power and Light Company ("JCP&L") base rate case (BPU Docket No. ER91121820J), dated June 15, 1993, at pages 7-8, the BPU held that:

> The Board believes that it is appropriate to reflect a consolidated tax savings adjustment where, as here, there has been a tax savings as a result of filing a consolidated tax return. Income from utility operations provides the ability to produce tax savings for the entire GPU system because utility income is offset by the annual losses of the other subsidiaries. Therefore, the ratepayers who produce the income that provides the tax benefits should share in those benefits. The Appellate Division has repeatedly affirmed the Board's policy of requiring utility rates to reflect consolidated tax savings and the IRS has acknowledged that consolidated tax adjustments can be made and there are no regulations which prohibit such an adjustment.

In the Board's Final Order, dated May 14, 2004, in the 2002 JCP&L base rate case, Docket No. ER02080506, page 45, it stated:

> As a result of making a consolidated tax filing during the years 1991-1999, GPU, JCP&L's parent company during that time period, as a whole paid less federal income taxes than it would have if each subsidiary filed separately, thus producing a tax savings. The law and Board policy are well-settled that consolidated tax savings are to be shared with customers.

The reality is that ConEd has elected to file a consolidated income tax return for its

4 I am not an attorney and therefore my comments are limited to the ratemaking implications of these findings. I am not testifying on any underlying legal issues associated with consolidated income tax adjustments.

subsidiaries, including RECO. Moreover, RECO was a member of a consolidated income tax group even prior to Consolidated Edison acquiring Orange and Rockland Utilities, Inc.(“O&R”), RECO’s parent company. Apparently, the filing of a consolidated tax return still offers advantages to RECO and members of the consolidated income tax group. Because ConEd has elected to file a consolidated tax return for its member companies, including RECO, I believe it is a settled matter that the tax savings should be shared with utility ratepayers.

Q. Why should these tax benefits be flowed through to the Company’s ratepayers?

A. These tax benefits should be flowed through to ratepayers because these benefits reflect the actual taxes paid. Establishing a revenue requirement based on a stand-alone federal income tax methodology would overstate the Company’s tax expense, result in a windfall to shareholders, and result in rates that are higher than necessary.

Q. How does ConEd determine the actual amount of taxes paid by RECO to its parent each year?

A. The payment of taxes is governed by a Tax Sharing Agreement among the members of the consolidated income tax group. Pursuant to the agreement, RECO, and other subsidiaries with positive taxable income, pay the amount of their stand-alone tax liability to the parent company. ConEd then pays the amount of taxes due by the consolidated group to the IRS. Any excess funds are used to compensate members of the consolidated income tax group with tax losses, to the extent that these tax losses can be used by the consolidated group. This arrangement therefore results in a contractual means to have the regulated and profitable subsidiaries subsidize unregulated and unprofitable ventures. These procedures transfer the excess amounts collected from ratepayers for income tax expense from the utility to the affiliates that generated the income tax losses, effectively resulting in a subsidization of the unregulated affiliates, and other unprofitable companies, by New Jersey ratepayers. In contrast, the consolidated income tax adjustment adopted by the BPU partially compensates ratepayers for this subsidization, by crediting ratepayers with carrying costs on these funds.

Q. How has the BPU traditionally calculated the consolidated income tax benefit for ratemaking purposes?

A. The BPU's long-established policy was adopted in a proceeding involving RECO, BPU Docket No. ER02100724, Order dated April 20, 2004. In that proceeding, the BPU calculated a consolidated income tax adjustment by allocating tax losses generated by companies with cumulative tax losses to all members of the consolidated income tax group that had cumulative positive taxable income. Pursuant to the BPU's methodology employed in that case, the first step is to determine if each company included in the consolidated group had cumulative taxable income or a cumulative tax loss for the period 1991 to the present, which I will refer to as the Review Period. This analysis results in two groups of companies, those with cumulative taxable income over the Review Period and those with cumulative tax losses.

The second step is to calculate the tax loss, by year, for those companies that had a cumulative taxable loss for the Review Period. The tax loss for each company in the group is then accumulated, by year, in order to determine the total annual loss for the consolidated group by year. The total annual loss, by year, is then multiplied by that year's annual federal income tax rate, in order to determine the tax loss benefit for the consolidated group by year. Adjustments are also made to reflect any alternative minimum tax ("AMT") payments made by the group. The annual tax loss benefits, net of AMT, are then accumulated for the entire Review Period, to determine the total tax loss benefit that is subject to allocation.

In step three, the accumulated tax loss benefit is then allocated to each company that had positive taxable income on a cumulative basis during the Review Period. The accumulated tax loss benefit is allocated based on the percentage share of each entity's positive taxable income to the total accumulated positive taxable income of the group.

Q. Did the BPU later initiate a generic proceeding to investigate the issue of consolidated income tax adjustments?

A. Yes, it did. The BPU issued an Order on January 23, 2013 in BPU Docket No. EO12121072, establishing a generic proceeding on the issue of consolidated income taxes. After comments from various parties, the BPU issued an Order on October 22, 2014 adopting certain modifications proposed by Board Staff. On December 17, 2014, the BPU issued a corrected order (BPU CTA Order) which reflected the earlier October 22, 2014 findings and revised an incorrect docket number in the original Order.

The revisions recommended by Staff and adopted by the BPU included:

- A limited time period of five years over which the consolidated tax adjustment would be calculated,
- The savings allocated to the New Jersey utility would be further allocated, such that ratepayers received only 25% of the utility's share of the consolidated income tax benefit, and
- Transmission assets would not be included in the allocation.

Rate Counsel filed an Appeal to the BPU CTA Order on March 9, 2015.

Q. What is the status of Rate Counsel's appeal?

A. Rate Counsel's appeal was upheld by the Court. The case was remanded to the BPU by the Appellate Division for rulemaking. The Board has since proposed two sets of regulations on consolidated income taxes, and adopted a final regulation using the same methodology proposed in the original order. Rate Counsel has since filed an appeal of the adopted regulation, which is currently pending before the Appellate Division.

Q. Did RECO include a consolidated income tax adjustment in this case?

A. Yes, the Company included a consolidated income tax adjustment based on the methodology required by the Board as part of a tariff filing in its regulations that are the subject of the appeal (N.J.A.C. 14:1-5.12(a)(11). This resulted in a rate base reduction of $23,000 based on the 9+3 Update.

Q. What do you recommend?

A. I have based my adjustment on the RECO methodology that has traditionally been used by the Board. To quantify my adjustment, I recommend that the BPU utilize the tax losses and taxable income for each ConEd subsidiary over the most recent twenty-year period. This is the period during which tax losses could be carried forward prior to the TCJA.[5] In addition, I have not further allocated any of the utility's share of the consolidated income tax benefit to shareholders. Shareholders are already receiving all such benefits that would otherwise be allocated to unregulated entities and/or to utilities in states that do not recognize a consolidated income tax adjustment for ratemaking purposes. Based on my recommended methodology, only 3.03% of the consolidated income tax benefit is allocated to New Jersey ratepayers. Finally, I have not excluded transmission assets from the calculation. Excluding transmission assets from the calculation would prevent ratepayers from receiving the tax benefit that accrued from ratepayer funds. In addition, it treats the New Jersey electric utilities differently from the other utilities in the state. Therefore, I have not excluded transmission assets from the calculation of my consolidated income tax adjustment.

Q. What is the result of your recommended consolidated income tax calculation?

A. My consolidated income tax adjustment results in a rate base deduction of $15.119 million, as shown in Schedule ACC-13. Since RECO has not yet provided data for its 2018 tax year,

5 As a result of the TCJA, tax losses can now be carried forward indefinitely.

which should have been finalized by September 15, 2019, my adjustment only reflects 19 years of actual data. However, this adjustment should be updated to reflect a full 20 years of data once the Company provides the 2018 tax data.

I. Summary of Rate Base Issues

Q. What is the impact of all of your rate base adjustments?

A. My recommended adjustments reduce the Company's rate base from $252.250 million, as reflected in its 9+3 Update, to $196.359 million, as summarized on Schedule ACC-3.

VI. OPERATING INCOME ISSUES

A. Salary and Wage Expense

Q. How did the Company determine its salary and wage expense claim in this case?

A. In its 9+3 Update, the Company made four adjustments to its Test Year salary and wage costs. First, it annualized a wage increase for weekly employees that was effective June 1, 2019. Second, it included an additional wage increase for weekly employees effective June 1, 2020. Third, it included a salary increase effective April 1, 2019 for monthly employees. Fourth, it included an additional increase effective April 1, 2020 for monthly employees. The Company's adjustments increased its pro forma expense claim by $539,000.

In addition to these salary and wage increases, it also included RECO's share of annualized costs for fifteen new employee positions. This includes nine management employees and six weekly employees. This adjustment increased the Company's pro forma expense claim by $124,000.

Q. Are you recommending any adjustment to the Company's claim for salaries and wages?

A. Yes, I am recommending that the Company's adjustments relating to post-test year salary and wage increases be excluded from the Company's revenue requirement. Therefore, I have excluded the Company's adjustments relating to the June 1, 2020 union increase as well as the adjustment relating to the April 1, 2020 non-union increase. I have also eliminated RECO's adjustment relating to new employee positions.

Q. What is the basis for your adjustment to remove the post-test year increases?

A. My adjustment is based on maintaining the integrity of the Test Year matching principle, matching the Test Year revenues, expenses and investment. The actual salary and wage expense incurred by the Company can vary depending upon the level of employees at any given time, the extent to which costs are allocated to RECO relative to other affiliates, capitalization ratios, and other factors. Therefore, while I have accepted the Company's adjustments that annualize salary and wage increases that took place during the Test Year, I have not included those adjustments that result from post-test year increases. My adjustment is shown in Schedule ACC-15.

Q. Did you include the RECO allocated costs for the fifteen new positions claimed by

RECO?

A. No, I did not. RECO's adjustment is based largely on the fact that the New York State Public Service Commission ("NYPSC") authorized these positions as part of the 2019 electric rate plan authorized for O&R in its recent New York base rate case. RECO does not have any of its own employees – rather it receives an allocation of O&R employee costs. While these employee positions may have been authorized by the NYPSC as part of a rate plan, RECO has not demonstrated that these new employees are needed to provide safe and reliable service in New Jersey. In addition, employee levels typically fluctuate every month for a company the size of O&R. To the extent that these employees were hired and providing service during the Test Year, then their costs will be included in the Company's Test Year results. However, I recommend that the BPU reject any additional post-test year adjustment related to costs that have not been shown to be required in New Jersey, simply because these costs were authorized by another regulatory commission. My adjustment to eliminate costs for these new employee positions is shown in Schedule ACC-16.

Q. Have you made a corresponding adjustment to the Company's payroll tax expense claim?

A. Yes, I have. Since I am recommending adjustments to the Company's claims for salaries and wages, it is necessary to make a corresponding adjustment to eliminate certain payroll taxes from the Company's revenue requirement claim. At Schedule ACC-17, I have eliminated payroll taxes associated with my recommended salary and wage adjustments. To quantify my adjustment, I utilized the pro forma payroll tax rate of 7.74%, which was reflected in the Company's filing, and applied it to my recommended adjustments for salaries and wages.

B. Incentive Compensation Plan Expense

Q. Please describe the Company's incentive compensation programs.

A. RECO offers several incentive compensation programs. First, officers participate in both a short-term Executive Incentive Plan ("EIP") and in a Long-Team Incentive Plan ("LTIP"), as discussed in the response to RCR-A-38. The EIP award parameters are heavily weighted toward financial parameters, although there are certain operational performance goals also included in the awards criteria. Approximately 75% of the EIP awards are based on financial goals. The Company included $113,132 in its 9+3 Update for EIP award costs allocated to RECO.

A small group of officers and executives are also eligible for awards pursuant to the Long-Term Incentive Plan ("LTIP"). The LTIP is an equity-based compensation plan that is even more heavily weighted toward financial parameters than the EIP. The Company included $341,063 of allocated LTIP costs for officers in its 9+3 Update.

All other management employees are eligible for an Annual Team Incentive Plan ("ATIP") award. ATIP awards are currently based on three metrics: 50% on customer service metrics, 25% on earnings metrics, and 25% on operating budget metrics. In addition, 60% of the total available ATIP award is based on team performance and 40% on individual performance. The Company has included ATIP costs of $1,433,000 in its 9+3 Update.

Q. Do you believe that the incentive compensation program costs are appropriate costs to pass through to ratepayers?

A. No, I do not. I have several concerns related to the inclusion of costs for these types of programs in regulated utility rates. With regard to management employees, a significant portion of these awards are based on financial benchmarks. In addition, the customer service benchmarks that are included in the performance criteria are not based on performance in New Jersey. Rather, the performance award criteria are evaluated at the system-wide, O&R level. Therefore, there is no assurance that even the customer service portion of these awards provides direct benefits to New Jersey ratepayers. In addition, RECO employees are well compensated independent of incentive compensation awards. Management employees have consistently been awarded annual payroll increases of 3.0% in each of the past four years.[6] There is no indication that the Company's employees are underpaid or that the Company would have difficulty attracting qualified employees in the absence of these programs.

In addition, officers are certainly well compensated. As shown in the most recent Proxy Statement, Robert Sanchez, President and Chief Executive Officer for O&R, had a base salary of $437,883 in 2018, and total compensation of $1.97 million. Mr. McAvoy, Chairman, President and CEO of Consolidated Edison, Inc. had a base salary of almost $1.3 million and total compensation of $9.76 million in 2018. In addition, incentive compensation awards for officers and executives are even more heavily weighted toward

6 Per the response to RCR-A-25.

financial parameters than the awards made to other management employees.

Q. Has the BPU previously addressed the issue of incentive compensation costs?

A. Yes. In the 2000 Middlesex Water Company base rate case, Board Staff argued in its Initial Brief that:

> Staff is persuaded by the arguments of the RPA [(Ratepayer Advocate)] that, at this time, the incentive compensation expenses should be not be recovered from ratepayers. According to the record, incentive compensation expenses have tripled since 1995. In addition, the record also indicated that the bonuses are significantly impacted by the Company achieving financial performance goals. These facts lend strength to the RPA's position that it is inappropriate for the Company to request recovery of bonuses in rates at this time.[7]

The Administrative Law Judge ("ALJ") in that case initially recommended that Middlesex be permitted to recover 50% of its incentive compensation costs in rates. However, the BPU rejected the ALJ's recommendation and instead ordered that 100% of these costs be disallowed.[8]

Q. Doesn't the Company use a compensation consulting firm to benchmark its compensation?

A. Yes, it does. The Company utilizes Mercer Consulting to evaluate its compensation practices and provide information on compensation at other companies to use as a benchmark for its compensation programs. However, the use of such benchmarks has a detrimental effect on

7 I/M/O the Petition of Middlesex Water Company for Approval of an Increase in Its Rates for Water Service and Other Tariff Charges, BPU Docket No. WR00060362, Staff Initial Brief, page 37.
8 I/M/O the Petition of Middlesex Water Company for Approval of an Increase in Its Rates for Water Service and Other Tariff Charges, BPU Docket No. WR00060362, Order Adopting in Part/Modifying in Part/Rejecting in Part Initial Decision at 25-26 (June 6, 2001).

ratepayers as compensation costs spiral, especially at the executive level.

Q. Why do you believe that the use of benchmarking results in spiraling executive compensation costs?

A. Companies state that they must benchmark their compensation in order to be competitive. However, such benchmarking actually results in ever-increasing executive compensation levels. This is because companies generally target their compensation to the 50th percentile of companies in the proxy group selected for benchmarking. Such practices tend to escalate increases in compensation, especially for highly-paid officers. These studies compare the subject company's compensation to compensation in a broad range of other firms. Since most companies do not want to find themselves in the lower half of the benchmark group, companies that typically fall below the average raise their compensation – and hence the average of the benchmark companies continually increases. This sets off a chain of events that results in ever-increasing compensation levels as additional companies must increase their compensation levels to avoid falling below the 50th percentile. The BPU should be particularly wary of any compensation plans that utilities attempt to justify by means of comparison to benchmark studies. It is not surprising that concurrent with the practice of benchmarking, executive compensation levels have risen dramatically over the past few years.

Q. What do you recommend?

A. I recommend that the BPU disallow 100% of the Company's claim for incentive compensation awards. I am recommending the disallowance of both management incentive compensation awards as well as officer and executive incentive award payments. The Company's employees are already well compensated, and the level of service being received by New Jersey ratepayers does not justify the payment of additional incentive awards. The ATIP awards are at least partially based on financial parameters that provide no benefit to New Jersey ratepayers. In addition, the performance criteria used to determine ATIP awards are not specific to New Jersey and there is no guarantee that the system-wide performance results mirror results in New Jersey. In addition, many of the non-financial benchmarks utilized to award incentive compensation are operational parameters that ratepayers have a right to expect – parameters such as reliability and customer service standards. Therefore, it is appropriate to eliminate 100% of the management incentive compensation payments.

With regard to executive and officer compensation, both the EIP and the LTIP are heavily dependent on financial criteria. Moreover, these officers and executives are already well compensated in their base salaries. Therefore, I believe it is also appropriate to eliminate 100% of the executive and officer incentive compensation awards reflected in the Company's filing. My adjustments to the Company's incentive compensation claim are shown in Schedule ACC-18.

C. Supplemental Retirement Income Program ("SRIP") Expense

Q. What are SRIP costs?

A. These costs relate to supplemental retirement benefits for key executives that are in addition to the normal retirement programs provided by the Company. These programs generally exceed various limits imposed on retirement programs by the IRS and therefore are referred to as "non-qualified" plans. As stated in the response to RCR-A-41, "Orange and Rockland's Supplemental Retirement Income Plan ("SRIP") provides certain management employees with a supplemental pension upon retirement if their pension benefit earned under the tax qualified Retirement Plan is limited by federal tax law. The SRIP formulas for active employees are the same as the pension formulas of the Retirement Plan. However, the SRIP formulas make up for pension benefits that have been earned but could not be paid under the Retirement Plan due to Internal Revenue Service ("IRS") limits imposed on the accrual and payment of pension benefits under tax qualified pension plans."

Q. What are the Test Year SRIP costs that the Company has included in its claim?

A. As shown in the response to RCR-A-41, the Company incurred total SRIP expense of $112,600 in the Test Year.

Q. Do you believe that these costs should be included in utility rates?

A. No, I do not. The officers of the Company are already well compensated. As noted previously, in 2018, base salary for the Named Executive Officers ("NEOs") ranged from

$437,883 for Mr. Sanchez to $1.297 million for Mr. McAvoy. In addition, all of the NEOs have substantial SRIP benefits, in addition to benefits provided under the qualified pension plan. Mr. McAvoy's accumulated benefit under the SRIP is $23.7 million according to the 2019 Proxy Statement. Moreover, the officers that receive SRIP benefits are also included in the normal retirement plans of the Company, so ratepayers are already paying retirement costs for these executives. If RECO wants to provide further retirement benefits to select officers and executives then shareholders, not ratepayers, should fund these excess benefits. Therefore, I recommend that the Company's claim for SRIP costs be disallowed. My adjustment is shown in Schedule ACC-19.

D. <u>Employee Benefit Expense</u>

Q. How did the Company determine its employee benefits expense claim in this case?

A. In its revenue requirement, RECO included a post-test year expense adjustment related to employee benefit costs. To determine this adjustment, the Company applied an employee benefits expense ratio of 20.95% to its claimed post-test year salary and wage adjustment. This ratio consists of 16.56% for employee health and welfare costs, 3.00% for thrift savings plans, and 1.39% for workers compensation and public liability costs. RECO's adjustment assumes a direct relationship between changes in payroll costs and changes in benefit costs.

Q. Are you recommending any adjustment to the Company's claim?

A. Yes, I am recommending that the Company's post-test year adjustment be rejected. RECO's adjustment is not based on known and measurable changes to actual test year costs. Instead, RECO's adjustment is based on a benefit loading rate that assumes a direct relationship between benefit costs and labor costs. However, the primary benefit component – employee health and welfare – is not directly proportional to changes in payroll costs. Therefore, I recommend that the BPU utilize the actual Test Year employee benefit costs to set rates in this case. My adjustment is shown in Schedule ACC-20.

E. <u>Rate Case Expense</u>

Q. How did the Company develop its claim for rate case costs relating to this case?

A. RECO's rate case expense claim is based on total estimated costs for the current rate case of $600,000, as shown in Exhibit P-2, Schedule 9 to its 9+3 Update. In response to RCR-A-54, the Company indicated that its rate base cost claim includes $500,000 in external legal costs and $100,000 for outside consulting services and miscellaneous expenses. The Company is proposing to amortize these costs over three years, for an annual expense of $200,000.

Q. Did the Company solicit competitive bids for rate case services relating to this case?

A. No, it did not. According to the response to RCR-A-57, the Company did not issue any Requests for Proposal for services associated with this rate case.

Q. Are you recommending any adjustment to the Company's claim for rate case costs?

A. Yes, I am recommending two adjustments. First, I am recommending a reduction in the pro forma costs projected for this case, since I believe that the Company's claim is excessive.

The estimated costs for the current case are significantly higher than the actual costs incurred in the last three base rate case proceedings, as shown below:[9]

	Rate Case Expense
2016 Case	$391,000
2014 Case	$335,000
2009 Case	$216,000
Average	$314,000

In order to determine a normalized level of rate case costs, I recommend that the BPU take into account the average of RECO's costs in its last three base rate proceedings. Since all three of these cases were settled, and there is a possibility that the current case will be fully litigated, I am recommending a rate case cost allowance of $400,000 for the current case. In addition, I have accepted the Company's proposal to use a three-year normalization period for rate case costs associated with the current proceeding. Accordingly, at Schedule ACC-21, I have made an adjustment to reflect prospective rate case costs of $400,000, based on a review of the costs for the last three rate cases, and a three-year normalization period.

Q. What is your second adjustment?

A. The BPU has a long-standing policy of requiring a 50/50 sharing of rate case costs between shareholders and ratepayers. This policy is based on the assumption that base rate case filings provide benefits to both shareholders and ratepayers, and therefore should be allocated equally between the two groups. The Company has not reflected any sharing of rate case

9 Per the response to RCR-A-70.

costs in its filing. Accordingly, at Schedule ACC-21, I have also made an adjustment to allocate 50% of the Company's pro forma annual rate case costs to shareholders.

F. AMI Meter Program Expense

Q. Did the Company include operating costs associated with the AMI Meter Program in its revenue requirement?

A. Yes, it did. In addition to the capital costs of the AMI Meter Program, which are discussed in the Rate Base section of my testimony, RECO also included various operating costs associated with the AMI Program in its claim. The Company's depreciation expense claim includes depreciation expense for the AMI meters and related communications equipment. In addition, RECO is requesting that the BPU authorize recovery of stranded costs associated with the legacy meters that are being replaced. RECO estimated stranded costs of $5.178 million, which it is proposing to amortize over a fifteen-year period. RECO also included a pro forma adjustment to reduce operating expenses to annualize reductions in meter readers that occurred during the Test Year. There may be other operating expenses associated with the AMI Program embedded in the Company's Test Year costs, but RECO stated that it was unable to identify all such operating expense impacts of the AMI Program.

Q. What is Rate Counsel's recommendation regarding the AMI Program and its associated costs?

A. Rate Counsel witness Paul Alvarez is sponsoring testimony on the underlying AMI Program.

According to Mr. Alvarez's analysis, RECO has not demonstrated that the AMI Program was prudent and the Company has not shown that the AMI Program resulted in benefits that exceed the associated costs. Therefore, I am recommending that the both the capital and operating costs of the AMI Program be excluded from the Company's revenue requirement.

Q. How did you quantify your operating cost adjustment relating to the AMI Program?

A. My operating expense adjustment consists of several components, as shown on Schedule ACC-22. First, I eliminated the depreciation expense on the AMI meters that was included in the Company's filing. Second, I eliminated the amortization of stranded costs that the Company had requested. Third, I reversed the Company's adjustment relating to labor savings resulting from meter readers that were terminated during the Test Year. Since I am removing the costs associated with the AMI Program, it is necessary to also remove the incremental cost savings that were identified in the Company's filing. Finally, I increased meter reading labor costs to reflect costs for 8 additional meter readers that were terminated prior to the beginning of the Test Year, on the assumption that these positions would not have been terminated except for the AMI Program.

Q. Did you also make an adjustment to include the depreciation expense on the legacy meters in your revenue requirement?

A. No, I did not. While it is my intent to include this depreciation expense in the revenue requirement, I did not make a separate adjustment relating to the depreciation expense for the legacy meters. This is because I don't believe that any additional adjustment is necessary. In the Company's filing, it applied its composite depreciation rate to the utility plant-in-service balance at the end of the Test Year. However, it appears that the test-year end plant balance still included the legacy meters. Therefore, it appears that the Company included recovery of the legacy meters twice – once through the depreciation expense calculated in Exhibit P-2, Schedule 16, and again in its stranded cost adjustment on Schedule 19. Therefore, there was no need for me to add back the depreciation expense on the legacy meters, since I believe that these costs are already embedded in the Company's depreciation expense claim. If the Company can demonstrate that it eliminated the depreciation expense for the legacy meters from its filing, then I would recommend an additional adjustment to reflect the depreciation expense on the legacy meters in the Company's revenue requirement.

Q. If the BPU permits the Company to recover the costs of the AMI Program, would you recommend any accounting adjustments?

A. Yes, I would recommend two adjustments. First, as discussed above, it appears that the Company has included depreciation expense for both the AMI meters and for the legacy meters in its revenue requirement. If the BPU authorizes the Company to recover the costs of the AMI Program, then it should ensure that all depreciation expenses related to the legacy meters are removed from prospective rates. In addition, if the BPU authorizes recovery of the AMI Program, then I recommend that it reject the Company's request to recover stranded costs.

Q. What is the basis for your recommendation?

A. It is a basic premise of utility ratemaking that ratepayers pay for investment that is used and useful in the provision of regulated utility service. To the extent that investment is not being used to provide utility service, then it should be excluded from regulated rates.

Shareholders assume the risk of non-recovery when they invest in a utility. Because of this risk, regulatory commissions typical authorize a higher return for equity investors than for bondholders. In this case, RECO has one shareholder, ConEd, who knew, or should have known, that it was assuming this risk when it invested in O&R, and ultimately in RECO. RECO has chosen to voluntarily remove all legacy meters and install AMI meters in their place before the legacy meters are fully depreciated. It is unreasonable for the Company to argue that ratepayers should bear all of the risk of stranded costs that results from that decision and that shareholders must be made whole for their entire investment, including earning both a return on, and a return of, that investment. Ratepayers should not be responsible for paying costs for two meters – the AMI meter and the legacy meter – when only one meter is being used to provide utility service. Therefore, if the BPU finds that the AMI Program is prudent and should be included in utility rates, then the BPU should also find that shareholders, and not ratepayers, should be responsible for stranded costs associated with plant that is no longer serving New Jersey customers.

G. Storm Damage Expense

Q. How is the Company proposing to treat storm damage costs in this case?

A. In addition to the rate base adjustment discussed earlier, RECO also has two operating expense adjustments relating to storm damage costs in its filing. First, the Company is requesting an increase in its annual storm reserve from $750,000 to $1,487,254. The Company's claim is based on the "level of storm costs that the Company would expect to incur over a five-year period."[10] This claim was based on historic storm costs for major storms over the past five years, excluding Storm Quinn. A major storm is defined by RECO as a storm that causes electric disruption for 10% or more of customers in an operating area or if customers are without power for more than 24 hours and incremental costs incurred for each individual storm exceeds $130,000. Following are the major storms (excluding Storm Quinn) identified by RECO in its filing:

Storm	Dates	Deferred Cost
2014 Storm #9 (Thanksgiving)	11/26/2014	$143,377
2017 Storm #2	2/13/2017	$306,151
2017 Storm #8	10/29/2017	$255,585
2018 Storm #1 (Riley)	3/2/2018	$1,460,453
2018 Storm #4	5/15/2018	$4,781,431
2019 Storm #2	2/24/2019	$489,273
Total		$7,436,269
Five Year Average		$1,487,254

10 Accounting Panel Testimony, page 58.

Q. Why did the Company exclude Storm Quinn from its calculation of normal, on-going storm costs?

A. RECO excluded Storm Quinn because the Company found that Storm Quinn was extraordinary, based on the magnitude of the costs involved. Instead of including costs for Storm Quinn in the calculation of its normal storm reserve, RECO is proposing that all unrecovered storm costs, including costs incurred for Storm Quinn, be amortized over a three-year period. RECO's claim includes recovery of $13.267 million, $10.048 of which relates to Storm Quinn.

Q. What level of storm damage costs are you recommending?

A. With regard to normal, on-going costs for major storms, I believe that the Company's use of the prior five-year average of major storms, excluding extraordinary storms, is reasonable. However, in calculating this normal level of storm costs, I recommend that the May 15, 2018 storm be excluded, along with Storm Quinn. Costs for the May 15, 2018 storm were $4.78 million, more than three times the magnitude of the next highest storm cost. Given the history of storms over the past five years, the May 15, 2018 storm also appears to qualify as an extraordinary storm event. Therefore, at Schedule ACC-23, I am recalculated the Company's storm reserve, using a five-year history excluding both Storm Quinn and the May 15, 2018 storm. This results in a normalized level of $530,967 for annual storm costs.

With regard to costs for Storm Quinn and the May 15, 2018 storm, I have included a five-year amortization of costs for both of these storms in my revenue requirement. Costs for

Storm Quinn and the May 15, 2018 storm were the only "extraordinary" storm costs incurred over the last five years. Therefore, I believe that a five-year amortization is more reasonable than the three-year amortization requested by RECO. This adjustment is shown in Schedule ACC-24. In addition, as discussed earlier, I am not recommending that any storm costs be included in the Company's rate base.

I have not included an amortization for other deferred storm costs, over and above those recovered through the storm reserve. Since I am separately addressing the costs for Storm Quinn and the May 15, 2018 storm, the annual allowance of storm costs over the past five years has been sufficient to allow the Company to recover all of its costs. However, even if the actual costs had exceeded the annual storm reserve allowance, I would still not recommend a true-up for all storm-related costs. Although the Stipulation in the Company's last base rate case permitted RECO to defer these costs, it did not guarantee recovery of any of the deferred costs. Utilities are not guaranteed recovery of all storm-related costs, just as they are not guaranteed recovery of most operating expenses. Instead, utility rates are established that reflect a normalized, on-going level of costs. If the Company's actual costs are lower than projected, the Company and its shareholders benefit. If the Company's costs are higher than projected, then the return to shareholders is reduced. Ratemaking is not a reimbursement system. Instead of guaranteeing recovery, the BPU should instead incorporate a normal, on-going level of prospective storm costs in rates. That is the purpose of the storm reserve, which is an accounting mechanism intended to smooth out fluctuations in costs from year to year. The storm reserve is not, and should not be, a mechanism to ensure dollar-for-dollar recovery of all storm related costs. That reserve should not become a mechanism to shift the risk of recovery from shareholders to ratepayers.

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Q. Are you making any other recommendation relating to storm costs?

A. Yes, in the Company's last case, the parties agreed to permit RECO to automatically defer major storm costs, as defined above. In this case, the Company is requesting authorization to continue this deferral treatment. In addition, it is requesting authorization to expand this deferral to costs that are incurred in obtaining the assistance of contractors and utility companies providing mutual assistance in reasonable anticipation that a major storm will occur, even if the weather event ultimately fails to meet the definition of a major storm.

I am recommending that the BPU reject the Company's request to expand the deferral to include costs incurred in anticipation of a major storm that does not occur. In addition, I am recommending that the BPU end the automatic deferral mechanism that allowed RECO to defer costs associated with certain storms without receiving specific BPU approval.

Q. What is the basis for your recommendation?

A. The Company's storm cost reserve is intended to provide the Company with the opportunity to recover a "normal" level of major storm costs. Unless a major storm is also an extraordinary event, then these costs should be recovered through the ratemaking allowance for the storm reserve. Between base rate cases, there are many components of the revenue requirement that vary from the amounts used to set rates in a utility's most recent base rate case. However, it is the Company's shareholders, not its ratepayers, who should bear the risk of these cost variations, just as it is the Company's shareholders, and not ratepayers, that benefit from higher than anticipated earnings.

In the event of a major storm that the Company deems extraordinary, it should file a specific request for deferred accounting. Deferred accounting should not be used routinely but should signal an event that deviates from the norm. As the BPU recently stated in the proceeding involving RECO's request to establish a tariff for Veterans' Organizations, Docket No. ER19010046, "extraordinary circumstances must be present in order to permit a utility to qualify for deferred accounting." In the event of such an extraordinary event, RECO has the ability to file a request for deferred accounting treatment with the BPU. It even has the option of filing a base rate case. Given RECO's storm reserve, which addresses a normal annualized level of major storm costs, and the ability to file a request for deferred accounting in the event of an extraordinary storm, the BPU should end the automatic deferral of all major storm costs.

Q. What type of information should RECO file in the event of an extraordinary storm?

A. In the event of an extraordinary storm, RECO should promptly seek authorization for deferred accounting from the BPU. In addition, any claims for recovery of deferred storm costs should be supported with detailed supporting documentation for the underlying storm costs. RECO should also be required to demonstrate that the deferred costs relate directly to the restoration of service in New Jersey, and are not simply allocations of costs that were incurred elsewhere in the O&R service territory.

H. Tree Removal Program Expense

Q. Please describe RECO's request to increase funding for tree removal.

A. RECO has included a post-test year adjustment of $500,000 to address emerald ash borer and other dead and deceased tree issues. The Company's vegetation management program is addressed in the testimony of Rate Counsel witnesses Mr. Salamone and Mr. Chang. As described in that testimony, RECO has not supported an increase in these costs over the actual Test Year expenditures. Therefore, at Schedule ACC-25, I have made an adjustment to eliminate this post-test year adjustment from the Company's revenue requirement.

I. Management Audit Fee Expense

Q. Please describe the Company's claim for recovery of management audit fees.

A. RECO was recently the subject of a BPU-ordered management audit conducted by Silverpoint Consulting LLC ("Silverpoint"). Silverpoint began the audit in January 2018 and submitted its Audit Report to the BPU on July 19, 2019. In this case, RECO is seeking to recover costs of $655,200 incurred as a result of the management audit. It is seeking to amortize these costs over 3 years and to include the unamortized balance in rate base. I addressed RECO's request for rate base treatment of these costs earlier in my testimony.

Q. Are you recommending any adjustment to RECO's request to recover these management audit costs over a three-year amortization period?

A. Yes, I am recommending two adjustments. First, I am recommending that the BPU limit RECO's recovery to 50% of the deferred management audit costs, or $327,600. My recommendation is based on the fact that RECO did not fully cooperate with Silverpoint in the auditing process. As discussed in comments on the Audit Report that were submitted by Rate Counsel on October 7, 2019, RECO and its parent company "failed to provide responses to multiple, critical discovery requests and failed to meet with auditors despite multiple requests to do so." Since RECO failed to cooperate, the BPU cannot be certain that the Audit Report is either accurate or complete. As noted by Rate Counsel in its audit comments, "[h]ad RECO responded to the auditor's requests for information and interviews, it is unclear whether the information provided would have resulted in different or additional recommendations." Given RECO's failure to cooperate fully in the management audit, the Company should not be permitted to recover 100% of its audit costs from ratepayers. Therefore, at Schedule ACC-26, I have made an adjustment to allocate only 50% of RECO's management audit costs to ratepayers.

In addition, I am recommending that these costs be amortized over a five-year period, instead of the three-year period requested by RECO. RECO's last two management audits were conducted in 2009 and 2018. Given the fact that was a nine-year period between RECO's last two management audit, a longer amortization period is appropriate. At Schedule ACC-26, I have amortized the ratepayer share of RECO's management audit cost over five years.

J. Credit Card Fee Expense

Q. Has RECO included fees associated with credit card payments in its revenue requirement claim?

A. Yes, it has. In April 2019, RECO announced that it would no longer charge a convenience fee to residential customers that use their credit and debit cards to pay their bills. O&R received approval for this change from the NYSPC and announced that it would apply this policy to its New Jersey residential customers as well. In this case, RECO has included an adjustment to recover fees associated with credit card payments from all ratepayers through its base distribution rates.

Q. Please describe the adjustment proposed by RECO.

A. RECO has included a post-test year adjustment of $60,000 related to credit card fees. In addition, it is proposing that amounts above or below $60,000 be deferred each year until the Company's next base rate case. RECO claims that this deferral is reasonable because of the uncertainty regarding the actual number of residential customers that will use credit or debit cards and therefore the actual level of fees that will be incurred.

Q. Are you recommending any adjustment relating to the Company's claim for credit card fees?

A. Yes, I am recommending that the Company's request to include these fees in base rates be denied. Credit card fees should be borne by those ratepayers who choose to use a credit card to pay for their utility service. In many cases, customers choose to utilize credit cards because of points, cash refunds, or other benefits that are directly tied to use of the card. It is unreasonable to ask other ratepayers to subsidize these benefits. Therefore, I am recommending that credit card fees continue to be borne by the actual customers that utilize them.

RECO states in its testimony that "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."[11] RECO's testimony completely misses the point. The Company's proposal won't benefit all residential customers, it will only shift costs from those customers that currently use credit or debit cards to all residential customers. While customers that use credit cards will save, others will pay more. It is unreasonable to pass these costs on to the general body of ratepayers, some of whom may not even have credit cards, especially when it is the individual user of the card who will receive the benefits offered by the credit card. Finally, the Company's claim of $60,000 is high relative to the five-year average of actual transaction costs over the last five years. For all these reasons, I am recommending that the Company's proposal to recover the costs of credit card fees from the general body of ratepayers be denied. My adjustment is shown in Schedule ACC-27.

11 Accounting Panel Testimony, page 70.

Q. If the BPU does approve recovery of credit and debit card convenience fees from all residential ratepayers, what level of cost should be reflected in base rates?

A. If the BPU approves the Company's request to recover these costs in base rates, then the costs included in the Company's revenue requirement should be based on annualized costs that reflect activity at the end of the Test Year. In addition, the Company's request to defer amounts associated with credit and debit card payments should be denied.

K. Industry Dues Expense

Q. Are you recommending any adjustment to the Company's claim for membership dues?

A. Yes, I am. In response to S-RECO-REV-19, the Company identified various membership dues that it included in its revenue requirement claim. These dues included payments to such organizations as the New Jersey Alliance for Action, New Jersey Energy Coalition, the New Jersey Utilities Association, and the Edison Electric Institute ("EEI").

Q. Are you recommending any adjustment to the industry dues included by the Company in its filing?

A. Yes, I am recommending that 100% of the dues paid to the New Jersey Alliance for Action, New Jersey Energy Coalition, and the New Jersey Utilities Association be disallowed. I am also recommending that 20% of the EEI dues be disallowed. These organizations engage in lobbying activities, the costs of which should not be charged to ratepayers. In addition to explicit lobbying costs, most of these organizations also engage in other activities that should not be charged to ratepayers, such as public affairs, media relations, and other advocacy initiatives.

Q. Are lobbying costs an appropriate expense to include in a regulated utility's cost of service?

A. No, they are not. Lobbying expenses are not necessary for the provision of safe and adequate utility service. Ratepayers have the ability to lobby on their own through the legislative process. Moreover, lobbying activities have no functional relationship to the provision of safe and adequate regulated utility service. If the Company were to immediately cease contributing to these types of efforts, utility service would in no way be disrupted. For all these reasons, I recommend that costs associated with lobbying be disallowed.

Similarly, public affairs, media relations, and other advocacy initiatives should not be charged to ratepayers. I recognize that the specific level of lobbying/public affairs/media activity varies from organization to organization. However, based on my review of these organizations and on recommendations in other utility rate proceedings, I believe that a 20% disallowance for EEI, and a 100% disallowance for the other organizations, is a reasonable overall recommendation. My adjustment is shown in Schedule ACC-28.

L. <u>Depreciation Expense</u>

Q. Have you made any adjustments to the Company's claim for pro forma depreciation expense?

A. Yes, I am recommending two adjustments. First, with regard to the Company's claim for new depreciation rates, Rate Counsel witness James Garren is recommending new depreciation rates that result in a reduction in depreciation expense from the amount included in the Company's claim. RECO's proposed depreciation rates result in a composite depreciation rate of 2.132%, while Mr. Garren is recommending depreciation rates that result in a composite depreciation rate of 1.92%. Therefore, at Schedule ACC-29, I have made an adjustment to apply Mr. Garren's recommended composite depreciation rate to the Company's plant balance at the end of the Test Year. This is the same methodology used by the Company to calculate its depreciation expense in this case.

In addition, since I am recommending that post-test year plant additions be excluded from rate base, it is necessary to make a corresponding adjustment to eliminate the associated depreciation expense. At Schedule ACC-30, I have made an adjustment to eliminate depreciation expense associated with the post-test year plant additions that I recommend be excluded from rate base. Thus, my pro forma depreciation expense is synchronized with Rate Counsel's recommended Test Year plant in-service-balance and with Rate Counsel's proposed depreciation rates.

M. Interest Synchronization

Q. Have you adjusted the pro forma interest expense for income tax purposes?

A. Yes, I have made this adjustment at Schedules ACC-31. It is consistent (synchronized) with my recommended rate base and with the capital structure and cost of capital recommendations of Mr. Kahal. Rate Counsel is recommending a lower rate base and a lower cost of debt than the rate base and debt cost included in the Company's filing. These adjustments result in a lower pro forma interest expense for the Company. This lower interest expense, which is an income tax deduction for state and federal tax purposes, will result in an increase to the Company's income tax liability under Rate Counsel's recommendations. Therefore, I have included an interest synchronization adjustment that reflects a higher pro forma income tax expense for the Company and a decrease to pro forma income at present rates.

N. Income Taxes and Revenue Multiplier

Q. What income tax factors have you used to quantify your adjustments?

A. As shown on Schedule ACC-32, I have used a composite income tax factor of 28.11%, which includes a corporate business tax rate of 9.0% and a federal income tax rate of 21%. These are the state and federal income tax rates contained in the Company's filing.

My revenue multiplier, which is shown in Schedule ACC-33, incorporates these tax rates. In addition, the revenue multiplier also includes the Company's proposed uncollectible rate of 0.20%, resulting in a revenue multiplier of 1.3938.

VII. REVENUE REQUIREMENT SUMMARY

Q. What is the result of the recommendations contained in your testimony?

A. My adjustments indicate a revenue deficiency of $5.817 million, as summarized on Schedule ACC-1.

Q. Have you quantified the revenue requirement impact of each of your recommendations?

A. Yes, at Schedule ACC-34, I have quantified the revenue requirement impact of each of the rate of return, rate base, and expense recommendations contained in this testimony.

Q. Does this conclude your testimony?

A. Yes, although I reserve my right to supplement my testimony if necessary.

APPENDIX A

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Rockland Electric Company	E	New Jersey	ER19050552	10/19	Revenue Requirements	Division of Rate Counsel
Avista Corporation	E/G	Washington	UE-190334/UG-190335	10/19	Revenue Requirements	Public Counsel Unit
Westar Energy, Inc.	E	Kansas	19-WSEE-355-TAR	6/19	JEC Capacity Purchase	Citizens' Utility Ratepayer Board
Empire District Electric Company	E	Kansas	19-EPDE-223-RTS	5/19	Revenue Requirements	Citizens' Utility Ratepayer Board
Public Service Electric and Gas Co.	E/G	New Jersey	EO18060629/ G018060630	3/19	Energy Strong II Program	Division of Rate Counsel
Southwestern Public Service Company	E	New Mexico	18-00308-UT	2/19	Voluntary Renewable Energy Program	Office of Attorney General
Zero Emission Certificate Program (Various Applicants)	E	New Jersey	EO18080899	1/19	Zero Emission Certificates Subsidy	Division of Rate Counsel
Public Service Company of New Mexico	E	New Mexico	18-00043-UT	12/18	Removal of Energy Efficiency Disincentives	Office of Attorney General
Kansas Gas Service	G	Kansas	18-KGSG-560-RTS	10/18	Revenue Requirements	Citizens' Utility Ratepayer Board
New Mexico Gas Company	G	New Mexico	18-00038-UT	9/18	Testimony in Support of Stipulation	Office of Attorney General
Kansas City Power and Light Company	E	Kansas	18-KCPE-480-RTS	9/18	Revenue Requirements	Citizens' Utility Ratepayer Board
Public Service Electric and Gas Co.	E/G	New Jersey	ER18010029/ GR18010030	8/18	Revenue Requirements	Division of Rate Counsel
Westar Energy, Inc.	E	Kansas	18-WSEE-328-RTS	6/18	Revenue Requirements	Citizens' Utility Ratepayer Board
Southwestern Public Service Company	E	New Mexico	17-00255-UT	4/18	Revenue Requirements	Office of Attorney General
Empire District Electric Company	E	Kansas	18-EPDE-184-PRE	3/18	Approval of Wind Generation Facilities	Citizens' Utility Ratepayer Board
GPE/ Kansas City Power & Light Co., Westar Energy, Inc.	E	Kansas	18-KCPE-095-MER	1/18	Proposed Merger	Citizens' Utility Ratepayer Board
Public Service Electric and Gas Co.	E	New Jersey	GR17070776	1/18	Gas System Modernization Program	Division of Rate Counsel
Southwestern Public Service Company	E	New Mexico	17-00044-UT	10/17	Approval of Wind Generation Facilities	Office of Attorney General
Kansas Gas Service	G	Kansas	17-KGSG-455-ACT	9/17	MGP Remediation Costs	Citizens' Utility Ratepayer Board
Atlantic City Electric Company	E	New Jersey	ER17030308	8/17	Base Rate Case	Division of Rate Counsel
Public Service Company of New Mexico	E	New Mexico	16-00276-UT	6/17	Testimony in Support of Stipulation	Office of Attorney General
Westar Energy, Inc.	E	Kansas	17-WSEE-147-RTS	5/17	Abbreviated Rate Case	Citizens' Utility Ratepayer Board
Kansas City Power and Light Company	E	Kansas	17-KCPE-201-RTS	4/17	Abbreviated Rate Case	Citizens' Utility Ratepayer Board
GPE/ Kansas City Power & Light Co., Westar Energy, Inc.	E	Kansas	16-KCPE-593-ACQ	12/16	Proposed Merger	Citizens' Utility Ratepayer Board

The Columbia Group, Inc., Testimonies of Andrea C. Crane

Company	Utility	State	Docket	Date	Topic	On Behalf Of
Kansas Gas Service	G	Kansas	16-KGSG-491-RTS	9/16	Revenue Requirements	Citizens' Utility Ratepayer Board
Public Service Company of New Mexico	E	New Mexico	15-00312-UT	7/16	Automated Metering Infrastructure	Office of Attorney General
Kansas City Power and Light Company	E	Kansas	16-KCPE-160-MIS	6/16	Clean Charge Network	Citizens' Utility Ratepayer Board
Kentucky American Water Company	W	Kentucky	2016-00418	5/16	Revenue Requirements	Attorney General/LFUCG
Black Hills/Kansas Gas Utility Company	G	Kansas	16-BHCG-171-TAR	3/16	Long-Term Hedge Contract	Citizens' Utility Ratepayer Board
General Investigation Regarding Accelerated Pipeline Replacement	G	Kansas	15-GIMG-343-GIG	1/16	Cost Recovery Issues	Citizens' Utility Ratepayer Board
Public Service Company of New Mexico	E	New Mexico	15-00261-UT	1/16	Revenue Requirements	Office of Attorney General
Atmos Energy Company	G	Kansas	16-ATMG-079-RTS	12/15	Revenue Requirements	Citizens' Utility Ratepayer Board
El Paso Electric Company	E	New Mexico	15-00109-UT	12/15	Sale of Generating Facility	Office of Attorney General
El Paso Electric Company	E	New Mexico	15-00127-UT	9/15	Revenue Requirements	Office of Attorney General
Rockland Electric Company	E	New Jersey	ER14030250	9/15	Storm Hardening Surcharge	Division of Rate Counsel
El Paso Electric Company	E	New Mexico	15-00099-UT	8/15	Certificate of Public Convenience - Ft. Bliss	Office of Attorney General
Southwestern Public Service Company	E	New Mexico	15-00083-UT	7/15	Approval of Purchased Power Agreements	Office of Attorney General
Westar Energy, Inc.	E	Kansas	15-WSEE-115-RTS	7/15	Revenue Requirements	Citizens' Utility Ratepayer Board
Kansas City Power and Light Company	E	Kansas	15-KCPE-116-RTS	5/15	Revenue Requirements	Citizens' Utility Ratepayer Board
Comcast Cable Communications	C	New Jersey	CR14101099-1120	4/15	Cable Rates (Form 1240)	Division of Rate Counsel
Liberty Utilities (Pine Buff Water)	W	Arkansas	14-020-U	1/15	Revenue Requirements	Office of Attorney General
Public Service Electric and Gas Co.	E/G	New Jersey	EO14080897	11/14	Energy Efficiency Program Extension II	Division of Rate Counsel
Exelon and Pepco Holdings, Inc.	E	New Jersey	EM14060581	11/14	Synergy Savings, Customer Investment Fund, CTA	Division of Rate Counsel
Black Hills/Kansas Gas Utility Company	G	Kansas	14-BHCG-502-RTS	9/14	Revenue Requirements	Citizens' Utility Ratepayer Board
Public Service Company of New Mexico	E	New Mexico	14-00158-UT	9/14	Renewable Energy Rider	Office of Attorney General
Public Service Company of New Mexico	E	New Mexico	13-00390-UT	8/14	Abandonment of San Juan Units 2 and 3	Office of Attorney General

APPENDIX B

SCHEDULES

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING SEPTEMBER 30, 2019
REVENUE REQUIREMENT SUMMARY ($000)

	Company Claim (A)	Recommended Adjustment	Recommended Position	
1. Pro Forma Rate Base	$252,250	($55,891)	$196,359	(B)
2. Required Cost of Capital	7.51%	-0.72%	6.79%	(C)
3. Required Return	$18,944	($5,620)	$13,324	
4. Operating Income @ Present Rates	4,306	4,845	9,151	(D)
5. Operating Income Deficiency	$14,638	($10,464)	$4,174	
6. Revenue Multiplier	1.3938	1.3938	1.3938	(E)
7. Revenue Increase	**$20,402**	**($14,585)**	**$5,817**	

Sources:
(A) Company Filing, Schedule P-2, Summary, (9&3) Update, Page 3.
(B) Schedule ACC-2.
(C) Schedule ACC-3.
(D) Schedule ACC-14.
(E) Schedule ACC-33.

Appendix B
Schedule ACC-2

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING SEPTEMBER 30, 2019
REQUIRED COST OF CAPITAL

	Capital Structure (%	Cost Rate (%)	Weighted Cost (%)
	(A)	(A)	
1. Long Term Debt	52.86%	4.90%	2.59%
2. Customer Deposits			0.00%
3. Common Equity	47.14%	8.90%	4.20%
4. Total Cost of Capital	100.00%		**6.79%**

Sources:
(A) Testimony of Mr. Kahal, Schedule MIK-1.

Appendix B
Schedule ACC-3

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING SEPTEMBER 30, 2019
RATE BASE SUMMARY ($000)

	Company Claim	Recommended Adjustment		Recommended Position
	(A)			
1. Utility Plant in Service	$377,643	($24,839)	(B)	$352,804
2. Plant Held for Future Use	209	(209)	(C)	0
3. Construction Work in Progress	5,061	(5,061)	(D)	0
Less:				
4. Accumulated Depreciation	(76,440)	2,594	(E)	(73,846)
5. Net Utility Plant	$306,473	($27,515)		$278,958
Plus:				
6. Working Capital	$12,793	($3,219)	(F)	$9,574
7. Deferred Regulatory Balances	550	(919)	(G)	(369)
8. Storm Reserve	9,538	(9,538)	(H)	0
				0
Less:				0
9. Net Pension/OBEP Liability	0	0		0
10. Customer Deposits	(2,851)	0		(2,851)
11. Advances for Construction	($1,884)	0		(1,884)
12. Acc. Deferred Income Taxes	(72,346)	396	(I)	(71,950)
13 Consolidated Income Taxes	(23)	(15,096)	(J)	(15,119)
14. Total Rate Base	**$252,250**	**($55,891)**		**$196,359**

Sources:
(A) Company Filing, Exhibit P-3, Summary, 9+3 Update.
(B) Schedules ACC-4 and ACC-5.
(C) Schedule ACC-6.
(D) Schedule ACC-7.
(E) Schedule ACC-5 and ACC-8.
(F) Schedule ACC-9.
(G) Schedule ACC-10.
(H) Schedule ACC-11.
(I) Schedules ACC-5 and ACC-12.
(J) Schedule ACC-13.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING SEPTEMBER 30, 2019
UTILITY PLANT IN SERVICE ($000)

1.	Company Claim	$9,369	(A)
2.	Recommended Adjustment	**($9,369)**	

Sources:
(A) Company Filing, Exhibit P-3, Schedule 1, (9+3) Update.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING SEPTEMBER 30, 2019
UTILITY PLANT IN SERVICE - AMI METERS ($000)

	Utility Plant in Service:		
1.	AMI Meters in Service	$15,470	(A)
2.	Recommended Plant Adjustment	**($15,470)**	
	Accumulated Depreciation:		
3.	Accumulated Depreciation - AMI Meters	($697)	(A)
4.	Recommended Acc. Dep. Adjustment	**$697**	
	Accumulated Deferred Income Taxes - AMI Meters:		
5.	ADIT - AMI Meters	($399)	(A)
6.	Recommended ADIT Adjustment	**$399**	

Sources:
(A) Response to RCR-A-109.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING SEPTEMBER 30, 2019
PLANT HELD FOR FUTURE USE ($000)

1.	Company Claim	$209	(A)
2.	Recommended Adjustment	**($209)**	

Sources:
(A) Company Filing, Exhibit P-3, Schedule 2, (9+3) Update.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING SEPTEMBER 30, 2019
CONSTRUCTION WORK IN PROGRESS ($000)

1.	Company Claim	$5,061	(A)
2.	Recommended Adjustment	**($5,061)**	

Sources:
(A) Company Filing, Exhibit P-3, Schedule 3, (9+3) Update.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING SEPTEMBER 30, 2019
ACCUMULATED DEPRECIATION ($000)

1.	Company Claim	($1,897)	(A)
2.	Recommended Adjustment	**$1,897**	

Sources:
(A) Company Filing, Exhibit P-3, Schedule 4, (9+3) Update.

Appendix B
Schedule ACC-9

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING SEPTEMBER 30, 2019
CASH WORKING CAPITAL ($000)
LEAD LAG STUDY RESULTS

1.	Recommended Cash Working Capital	$3,564	(A)
2.	Company Claim	6,783	(B)
3.	Recommended Adjustment	**($3,219)**	

Sources:
(A) Reflects Rate Counsel adjustments. See Crane CWC Workpaper.
(B) Company Filing,Exhibit P-3, Schedule 6, (9+3) Update, Page 1.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING SEPTEMBER 30, 2019
DEFERRED REGULATORY BALANCES ($000)

1.	Company Claim	$550	(A)
2.	Federal Tax Reform Balance	(369)	(A)
3.	Total Recommended Adjustment	**($919)**	

Sources:
(A) Company Filing, Exhibit P-3, Schedule 7, (9+3) Update.

Appendix B
Schedule ACC-11

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING SEPTEMBER 30, 2019
STORM RESERVE ($000)

1.	Company Claim	$9,538	(A)
2.	Total Recommended Adjustment	**($9,538)**	

Sources:
(A) Company Filing, Exhibit P-3, Schedule 8, (9+3) Update.

Appendix B
Schedule ACC-12

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING SEPTEMBER 30, 2019
ACCUMULATED DEFERRED INCOME TAXES

1.	Company Claim	($72,346)	(A)
2.	Test Year Balance	(72,349)	(A)
3.	Recommended Adjustment	**($3)**	

Sources:
(A) Company Filing, Exhibit P-3, Schedule 11, (9+3) Update.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING SEPTEMBER 30, 2019
CONSOLIDATED INCOME TAXES ($000)

1. Sum of Net Taxable Losses for Companies With Cumulative Taxable Losses	$1,425,943	(A)
2. Tax Loss Benefit Based on Annual Federal Income Tax Rate	499,080	(A)
3. Share of RECO Cumulative Positive Taxable Income to Total for Companies With Cumulative Taxable Income	3.03%	(A)
4. Total CIT Adjustment for RECO	$15,119	
5. Company Claim	23	(B)
6. Recommended Adjustment	**($15,096)**	

Sources:
(A) Reflects Rate Counsel adjustments, based on the response to RCR-A-14 Supplement.
(B) Company Filing, Exhibit P-3, Schedule 13 (9+3) Update.

Appendix B
Schedule ACC-14

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING SEPTEMBER 30, 2019
OPERATING INCOME SUMMARY ($000)

			Schedule
1.	Company Claim	$4,306	
	Recommended Adjustments:		
2.	Salary and Wage Expense	$247	15
3.	Additional Employees Expense	89	16
4.	Payroll Tax Expense	26	17
5.	Incentive Compensation Expense	1,357	18
6.	SERP Expense	81	19
7.	Employee Benefits Expense	82	20
8.	Rate Case Expense	96	21
9.	AMI Program Meter Expense	340	22
10.	Annual Storm Funding Expense	687	23
11.	Extraordinary Storm Expense	1,047	24
12.	Tree Removal Program Expense	359	25
13.	Management Audit Fee Expense	61	26
14.	Credit Card Fee Expense	43	27
15.	Industry Dues Expense	44	28
16.	Depreciation Expense - New Rates	561	29
17.	Depreciation Expense - Post Test Year Plant	144	30
18.	Interest Synchronization	(421)	31
19.	Operating Income	**$9,151**	

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING SEPTEMBER 30, 2019
SALARY AND WAGE EXPENSE ($000)

1.	Company Claim		$539	(A)
2.	Rate Counsel Recommendation		195	(B)
3.	Recommended Adjustment		$344	
4.	Income Taxes @	28.11%	97	
5.	Operating Income Impact		**$247**	

Sources:
(A) Company Exhibit P-2, Schedule 4, (9+3) Update.
(B) Reflects elimination of 2020 increases.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING SEPTEMBER 30, 2019
ADDITIONAL EMPLOYEES EXPENSE

1.	Recommended Adjustment		$124	(A)
2.	Income Taxes @	28.11%	35	
3.	Operating Income Impact		**$89**	

Sources:
(A) Company Exhibit P-2, Schedule 4, 9+3 Update.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING SEPTEMBER 30, 2019
PAYROLL TAX EXPENSE ($000)

1.	Salary and Wage Adjustments		$468	(A)
2.	Payroll Tax Rate		7.74%	(B)
3.	Recommended Payroll Tax Adjustment		$36	
4.	Income Taxes @	28.11%	10	
5.	Operating Income Impact		**$26**	

Sources:
(A) Schedule ACC-15 and Schedule ACC-16.
(B) Reflects tax rate per Exhibit P-2, Schedule 20 (9+3) Update.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING SEPTEMBER 30, 2019
INCENTIVE COMPENSATION EXPENSE ($000)

1. Employee Incentive Compensation Expense		$1,433	(A)
2. Officer Incentive Compensation Expense		454	(A)
3. Total Recommended Adjustment		$1,888	
4. Income Taxes @	28.11%	531	
5. Operating Income Impact		**$1,357**	

Sources:
(A) Response to RCR-A-107.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING SEPTEMBER 30, 2019
SUPPLEMENTAL RETIREMENT INCOME PLAN EXPENSE ($000)

1.	Recommended Adjustment		$113	(A)
2.	Income Taxes @	28.11%	32	
3.	Operating Income Impact		**$81**	

Sources:
(A) Response to RCR-A-41.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING SEPTEMBER 30, 2019
EMPLOYEE BENEFITS EXPENSE ($000)

1.	Recommended Adjustment		$114	(A)
2.	Income Taxes @	28.11%	32	(A)
3.	Operating Income Impact		**$82**	

Sources:
(A) Company Filing, Exhibit P-2, Schedule 5, (9+3) Update.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING SEPTEMBER 30, 2019
RATE CASE EXPENSE ($000)

1. Recommended Expense		$400	(A)
2. Recommended Amortization Period		3	(B)
3. Annual Amortization		$133	
4. Allocation to Ratepayers (%)		50.00%	(C)
5. Allocation to Ratepayers ($)		$67	
6. Company Claim - Annual Expense		200	(D)
7. Recommended Adjustment		$133	
8. Income Taxes @	28.11%	37	
9. Operating Income Impact		**$96**	

Sources:
(A) Based on a review of last three base rate cases.
(B) Company Filing, Exhibit P-2, Schedule 9, (9+3) Update.
(C) Recommendation of Ms. Crane.
(D) Excludes underrecovery from prior case.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING SEPTEMBER 30, 2019
AMI METERS - OPERATING EXPENSE ($000)

1. Annual Depreciation Expense - AMI		$791	(A)
2. Amortization of Legacy Meters		345	(B)
3. Additional Meter Readers - Test Year		(97)	(C)
4. Additional Meter Readers - Pre Test Year		(566)	(D)
5. Total Operating Expense		$473	
6. Income Taxes @	28.11%	133	
7. Operating Income Impact		**$340**	

Sources:
(A) Response to RCR-A-109.
(B) Company Filing, Exhibit P-2, Schedule 19 (9+3) Update.
(C) $75,000 per Company Filing, Exhibit P-3, Schedule 10 (9+3) Update, adjusted to include payroll taxes and fringe benefit costs.
(D) Reflects 8 additional meter readers, based on actual meter readers in December, 2017. Reflects payroll of $55,000 per meter reader plus taxes and fringe benefit costs.

Appendix B
Schedule ACC-23

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING SEPTEMBER 30, 2019
ANNUAL STORM FUNDING EXPENSE ($000)

			(A)	
1.	2014 Storm #9 (Thanksgiving)		$143	
2.	2017 Storm #2		306	
3.	2017 Storm #8		256	
4.	2018 Storm #1 (Riley)		1,460	
5.	2019 Storm #2		489	
6.	Five Year Total		$2,655	
5.	Five Year Average		$531	
6.	Company Claim		1,487	(A)
7.	Recommended Adjustment		$956	
8.	Income Taxes @	28.11%	269	
9.	Operating Income Impact		**$687**	

Sources:
(A) Company Filing, Exhibit P-2, Schedule 14, (9+3) Update, Page 1.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING SEPTEMBER 30, 2019
EXTRAORDINARY STORM COST EXPENSE ($000)

1.	Storm Quinn Costs	$10,049	(A)
2.	May 15, 2018 Storm Costs	4,781	(A)
3.	Total "Extraordinary" Storm Costs	$14,830	
4.	Recommended Amortization (Yrs.)	5	(B)
5.	Annual Amortization	$2,966	
6.	Company Claim	4,422	(A)
7.	Recommended Adjustment	$1,456	
8.	Income Taxes @ 28.11%	409	
9.	Operating Income Impact	**$1,047**	

Sources:
(A) Company Filing, Exhibit P-2, Schedule 14, (9+3) Update, Page 1.
(B) Recommendation of Ms. Crane.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING SEPTEMBER 30, 2019
DANGER TREE PROGRAM EXPENSE ($000)

1.	Recommended Adjustment		$500	(A)
2.	Income Taxes @	28.11%	141	
3.	Operating Income Impact		**$359**	

Sources:
(A) Company Filing, Exhibit P-2, Schedule 12,(9+3) Update, Page 1.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING SEPTEMBER 30, 2019
MANAGEMENT AUDIT EXPENSE ($000)

1. Deferred Management Audit Fees		$655	(A)
2. Allocation to Ratepayers (%)		50.00%	(B)
3. Allocation to Ratepayers ($)		$328	
4. Recommended Amortization (Yrs.)		5	(B)
5. Annual Amortization Expense		$66	
6. Company Claim		218	(A)
7. Recommended Adjustment		$153	
8. Income Taxes @	28.11%	92	
9. Operating Income Impact		**$61**	

Sources:
(A) Company Filing, Schedule 14, (9&3) Update, Page 2.
(B) Recommendation of Ms. Crane.

Appendix B
Schedule ACC-27

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING SEPTEMBER 30, 2019
CREDIT CARD FEES ($000)

1.	Total Recommendation Adjustment		$60	(A)
2.	Income Taxes @	28.11%	17	
3.	Operating Income Impact		**$43**	

Sources:
(A) Company Filing, Exhibit P-2, Schedule 12, (9+3) Update, Page 1.

Appendix B
Schedule ACC-28

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING SEPTEMBER 30, 2019
INDUSTRY DUES EXPENSE ($000)

		Amount	Recommended Adjustment (%)	Recommended Adjustment ($)
		(A)	(B)	
1. NJ Alliance for Action		$1	100.00%	1
2. NJ Energy Coalition		1	100.00%	1
3. NJ Utilities Association		51	100.00%	51
4. Edison Electric Institute		38	20.00%	8
5. Total Recommended Tax Adjustment				$61
6. Income Taxes @	28.11%			17
7. Recommended Adjustment				**$44**

Sources:
(A) Response to S-RECO-REV-19.
(B) Recommendation of Ms. Crane.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING SEPTEMBER 30, 2019
DEPRECIATION EXPENSE - NEW RATES ($000)

1.	Company Proposed Composite Rate		2.13%	(A)
2.	Rate Counsel Proposed Composite Rate		1.92%	(B)
3.	Recommended Adjustment (%)		0.21%	
4.	Distribution Plant at September 30, 2019		$368,274	(A)
5.	Recommended Adjustment		$781	
6.	Income Taxes @	28.11%	219	
7.	Operating Income Impact		**$561**	

Sources:
(A) Company Filing, Exhibit P-2, Schedule 16, (9+3) Update.
(B) Workpaper of Mr. Garren.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING SEPTEMBER 30, 2019
DEPRECIATION EXPENSE - POST TEST YEAR PLANT ($000)

1.	Recommended Adjustment		$200	(A)
2.	Income Taxes @	28.11%	56	
3.	Operating Income Impact		**$144**	

Sources:
(A) Company Filing, Exhibit P-2, Schedule 17, (9+3) Update.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING SEPTEMBER 30, 2019
INTEREST SYNCHRONIZATION ($000)

1. Pro Forma Rate Base		$196,359	(A)
2. Weighted Cost of Debt		2.59%	(B)
3. Pro Forma Interest Expense		$5,086	
4. Company Claim		6,584	(C)
5. Recommended Adjustment		$1,498	
6. Increase in Income Taxes @	28.11%	**$421**	

Sources:
(A) Schedule ACC-3.
(B) Schedule ACC-2.
(C) Company Filing, Exhibit P-2, Schedule 23, (9+3) Update.

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING SEPTEMBER 30, 2019
INCOME TAX RATE

1. Revenue		100.00%	
2. State Income Taxes @	9.00%	9.00%	(A)
3. Federal Taxable Income		91.00%	
4. Income Taxes @	21.00%	19.11%	(A)
5. Operating Income		71.89%	
6. Total Tax Rate		**28.11%**	(B)

Sources:
(A) Reflects statutory rates.
(B) Line 1 - Line 5.

Appendix B
Schedule ACC-33

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING SEPTEMBER 30, 2019
REVENUE MULTIPLIER

1. Revenue		100.00%	
Less:			
2. Uncollectibles		0.20%	(A)
3. Taxable Income		99.80%	
4. State Income Taxes @	9.00%	8.98%	(A)
5. Federal Taxable Income		90.82%	
6. Income Taxes @	21.00%	19.07%	(A)
7. Operating Income		71.75%	
8. Total Tax Rate		**28.05%**	(B)
9. Revenue Multiplier		**1.3938**	(C)

Sources:
(A) Company Filing, Exhibit P-2, Summary (9+3) Update, Page 3.
(B) Line 6 + Line 8.
(C) Line 1 / Line 9.

Appendix B
Schedule ACC-34

ROCKLAND ELECTRIC COMPANY
TEST YEAR ENDING SEPTEMBER 30, 2019
REVENUE REQUIREMENT IMPACT OF ADJUSTMENTS ($000)

1.	Capital Structure/Cost of Capital	($2,547)
	Rate Base Adjustments:	
2.	Utility Plant in Service	(886)
3.	Plant Held For Future Use	(20)
4.	AMI Meters	(1,359)
5.	Construction Work in Progress	(479)
6.	Accumulated Depreciation	179
7.	Cash Working Capital	(304)
8.	Deferred Regulatory Balances	(87)
9.	Storm Reserve	(902)
10.	Acc. Deferred Income Taxes	(0)
11.	Consolidated Income Taxes	(1,428)
	Operating Income Adjustments	
12.	Salary and Wage Expense	(345)
13.	Additional Employees Expense	(125)
14.	Payroll Tax Expense	(36)
15.	Incentive Compensation Expense	(1,891)
16.	SERP Expense	(113)
17.	Employee Benefits Expense	(114)
18.	Rate Case Expense	(134)
19.	AMI Program Meter Expense	(474)
20.	Annual Storm Funding Expense	(958)
21.	Extraordinary Storm Expense	(1,459)
22.	Tree Removal Program Expense	(501)
23.	Management Audit Fee Expense	(85)
24.	Credit Card Fee Expense	(60)
25.	Industry Dues Expense	(61)
26.	Depreciation Expense - New Rates	(782)
27.	Depreciation Expense - Post Test Year Plant	(200)
28.	Interest Synchronization	587
29.	Total Recommended Adjustments	($14,585)
30.	Company Claim	20,402
31.	Recommended Revenue Deficiency	**$5,817**