RIKER
DANZIG
SCHERER
HYLAND
PERRETTI LLP

ATTORNEYS AT LAW

James C. Meyer
Partner

Direct:
t: 973.451.8464
f: 973.451.8688
jmeyer@riker.com
Reply to: Morristown

May 3, 2019

BY HAND DELIVERY
Honorable Aida Camacho-Welch
Secretary
Board of Public Utilities
44 South Clinton Ave, 3d Floor Suite 314
P.O. Box 350
Trenton, NJ 08625-0350

Re: I/M/O 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.______________

Dear Secretary Camacho-Welch:

On behalf of Rockland Electric Company (the "Company"), enclosed for filing please find an original and eleven copies of the Company's Verified Petition for Approval of Changes In Electric Rates, Its Tariff For Electric Service, And Its Depreciation Rates, And For Other Relief. Rockland Electric Company will provide a copy of this filing to the Municipal Clerks, the County Executive, the Board of Chosen Freeholders and libraries in its service territory. Two hard copies are being provided to the Division of Law and to the Division of Rate Counsel. A copy of this filing also will be available on the Company's website at www.oru.com. In addition, a copy of this cover letter and a web link to the Company's Petition will be provided by electronic mail to the individuals on the attached service list.

As noted in the Petition, pursuant to N.J.A.C. 14:1-5.12(d), Rockland Electric Company will combine the notices of the Petition and of the public hearings and will provide them in accordance with the Board's regulations governing notice of the public hearings.

Please date stamp the enclosed extra copy of this cover letter as "filed", and return it in the enclosed self-addressed postage-paid envelope. Please contact me if you have any questions regarding this matter.

Respectfully submitted,

By: ____________________________
James C. Meyer
Riker, Danzig, Scherer, Hyland & Perretti LLP
Headquarters Plaza
One Speedwell Avenue
P.O. Box 1981
Morristown, New Jersey 07962-1981

And

John L. Carley
Assistant General Counsel
Consolidated Edison Company of New York, Inc.
Law Department, Room 1815-S
4 Irving Place
New York, NY 10003

Attorneys for Rockland Electric Company

Enclosure/c:

(2 copies of filing by Hand Delivery)
Stefanie Brand, Director
Division of Rate Counsel
140 East Front Street 4th Floor
Trenton, NJ 08625

(2 copies of filing by U.S. Mail)
Peter Van Brunt, DAG
Department of Law and Public Safety
124 Halsey Street, 5th Floor
P.O. Box 45029
Newark, New Jersey 07101-45029

Service List (copy of cover letter and web link by email)

5036394v1

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

Rockland Electric Company
Docket No. _________________

Direct Testimony

Volume I

ROCKLAND ELECTRIC COMPANY

TESTIMONY

ROCKLAND ELECTRIC COMPANY
DIRECT TESTIMONY OF
ACCOUNTING PANEL

NJBPU Docket No. _____________

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

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

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

A. (de la Bastide) I am employed by Orange and Rockland Utilities, Inc. ("Orange and Rockland" or "O&R"), the parent company of Rockland Electric Company ("RECO" or the "Company"), where I hold the position of Director – Financial Services.
(Ryan) I am employed by Consolidated Edison Company of New York, Inc. ("Con Edison" or "CECONY"), a utility affiliate of O&R and RECO, where I hold the position of Department Manager of Regulatory Filings.
(Wang) I am employed by CECONY, where I hold the position of Department Manager of Regulatory Accounting and Revenue Requirements.

Q. Please briefly outline your educational and business experience.

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

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

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

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

Q. Have you previously submitted testimony before the Board?

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

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

(Ryan) No.

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

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

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

P-1 Historical Financial Statements;

P-2 Electric Cost of Service; and

P-3 Electric Rate Base.

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

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

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

<u>BACKGROUND</u>

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

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

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

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

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

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

Q. Why is RECO filing this base rate case?

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

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

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

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

A. Yes.

Q. Please discuss.

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

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

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

- The second rate change resulted from the Board's Decision and Order dated June 22, 2018 in BPU Docket No. ER18030236 ("TCJA Order"). This Order reflected in the Company's rates the impact of the December 22, 2017 Federal Tax Cuts and Job Act ("TCJA"). Applying the changes enacted by the TCJA to RECO's annual federal income tax expense, the Board authorized a one-time refund of approximately $1.019 million to the Company's customers during July 2018, relating to the Stub Period (*i.e.*, January 1 through March 31, 2018) over-collection. The Board also implemented a reduction in the Company's annual revenue requirement of $2.868 million resulting from the TCJA's decrease in the statutory federal income tax rate from 35% to 21%, effective April 1, 2018. Finally, the Board authorized the Company to refund to its customers the unprotected accumulated deferred income taxes of approximately $10.6 million (grossed up amount), inclusive of SUT, over a three-year period, commencing in July 1, 2018. Excluding the one-time refund of $1.019 million made during July 2018, the annual reduction to base rates through June 2020 relating to the TCJA will be $6.4 million (*i.e.*, $2.868 million plus $3.553 million [$10.6 million / 3 years]).

- The third rate change that became effective on August 1, 2018, reduced the Company's base rates by $6,413,091 in order to eliminate the four-year recovery of deferred extraordinary storm damage costs of approximately $25,652,364 pursuant to the Board's Order Approving Stipulation dated July 23, 2014 in *I/M/O the Verified Petition of Rockland Electric Company for Approval of Changes in Electric Rates, et al., (*BPU Docket No. ER13111135).

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

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

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

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

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

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

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

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

A fairly significant portion of the Company's current filing is to recover deferred storm costs incurred through the end of the Test Year. Absent any new storm costs between now and September 30, 2019, the Company will have approximately $13.3 million of deferred storm costs. The total impact of recovering the deferred storm costs over three years, combined with the additional annual funding of $750,000 the Company is seeking to fund the current Storm Reserve (along with carrying costs on the deferred balance), represents approximately $6.1 million ($13.3 million / three years plus $750,000, plus $1.0 million of carrying cost on $13.3 million of deferred expenditures) of the rate increase the Company is requesting in this case. Had the prior annual storm cost recoveries of $6.4 million continued (instead of being eliminated August 1, 2018) and been reflected on the Company's books for the benefit of customers, those amounts could have been used in part, to avoid the impact of first lowering and then increasing customer rates to recover new deferred storm costs.

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

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

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

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

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

Q. What changes to distribution rates is RECO proposing?

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

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

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

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

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

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

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

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

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

HISTORIC FINANCIAL STATEMENTS

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

A. Yes.

Q. Please describe its contents.

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

Q. Please describe Schedules 2 and 3.

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

Q. Please describe Schedule 4.

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

Q. Please describe Schedule 5.

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

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

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

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

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

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

73,720 / 444,150 = 16.60%

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

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

73,720 / 307,266 = 23.99%

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

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

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

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

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

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

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

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

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

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

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

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

<u>RATE BASE</u>

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

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

Q. Please describe Schedule 1.

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

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

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

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

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

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

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

Q. Please describe Schedule 2.

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

Q. Please describe Schedule 3.

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

Q. Please describe Schedule 4.

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

Q. Please describe Schedule 5.

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

Q. Please describe Schedule 6.

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

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

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

Q. Please describe Schedule 7.

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

Q. Please describe Schedule 8.

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

Q. Please describe Schedule 9.

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

Q. Please describe Schedule 10.

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

Q. Please describe Schedule 11.

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

Q. What does Schedule 12 show?

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

Q. Please describe Schedule 13.

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

CASH WORKING CAPITAL

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

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

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

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

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

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

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

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

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

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

Q. Please describe the treatment of salaries and wages.

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

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

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

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

Q. How was the lag for the JOA calculated?

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

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

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

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

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

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

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

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

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

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

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

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

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

ELECTRIC COST OF SERVICE

Q. Please describe Exhibit P-2.

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

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

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

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

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

Q. Please begin and explain adjustment No. 1

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

Q. Please describe adjustment No. 2.

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

Q. Please continue.

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

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

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

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

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

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

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

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

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

Q. What wage increase percentages were used?

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

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

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

A listing of these new positions is also set forth in Attachment A to this testimony. The wage increase amounts summarized on Exhibit P-2, Schedule 4, Page 2 of 2, also include the portion of the salary expense of these new positions that is allocated to RECO and the escalation, calculated at the wage increase rates stated above, as applied to these salaries. The amount of salary and escalation allocated to RECO was calculated separately for each new position based on the specific job-related duties of each position.

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

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

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

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

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

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

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

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

systems related disaster recovery preparation, Personally Identifiable Information ("PII") protections and cyber security planning.

The combination of RECO's ongoing effort to implement new technologies and automate processes will continue to place additional strain on the Customer Systems department. The two Technical Programmers will have the knowledge and expertise in technical programming and will serve as an additional resource to code and test system enhancements.

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

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

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

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

<u>Annual Management Compensation Program</u>

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

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

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

Q. Please describe the O&R ATIP.

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

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

Q. Please continue with a description of the ATIP.

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

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

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

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

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

Q. Please describe the ATIP goals for 2019.

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

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

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

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

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

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

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

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

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

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

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

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

Q. Please address adjustment No. 5.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Q. When did the Company introduce employee contributions?

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

Q. Please describe adjustment No. 6.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Q. Please address adjustment No. 8.

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

Q. Please continue with adjustment No. 9.

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

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

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

Q. Please explain adjustment No. 10.

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

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

Q. Please address adjustment No. 11.

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

Q. Please describe adjustment No. 12

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

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

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

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

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

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

Q. Please discuss proposed adjustment No. 13.

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

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

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

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

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

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

Q. Please explain adjustment 14(b).

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

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

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

Q. Please describe adjustment No. 15.

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

Q. Please describe adjustment No. 16.

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

Q. Please describe adjustment No. 17.

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

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

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

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

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

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

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

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

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

Q. Please continue with adjustment No. 20.

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

Q. Please describe adjustments Nos. 21 and 22.

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

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

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

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

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

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

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

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

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

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

Q. Please describe adjustment No. 23.

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

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

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

2017 and 2018 Storm Hardening Filings

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

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

Q. How was the adjustment calculated?

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

Q. What is the impact of this adjustment?

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

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

A. No.

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

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

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

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

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

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

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

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

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

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

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

<u>"No-Fee" Debit/Credit Card Transactions</u>

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

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

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

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

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

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

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

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

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

Q. When would the Company implement this change?

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

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

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

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

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

Q. Does that conclude your direct testimony?

A. Yes, it does.

ROCKLAND ELECTRIC COMPANY
2019 Base Rate Case
Additional Employee Positions Requested

Accounting Panel
Attachment A

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

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

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

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

CUSTOMER SERVICE PERFORMANCE – Weighted at 50%

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

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

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

1. Employee and Public Safety

1. Injury/Illness Incidence Rate – Target ≤ 1.00

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

2. Significant High Hazard Injuries – Target = 0

Achieve a goal of zero.

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

3. Motor Vehicle Collisions – Target ≤ 38

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

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

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

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

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

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

2. **Environment and Sustainability**

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

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

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

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

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

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

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

   The twelve-month average monthly inventory is calculated by summing, at year-end, the total leak backlog (Type 1, 2A, 2 and 3 as defined in PSC code) at the end of each month and dividing by 12. The year-end average monthly inventory cannot exceed 40.

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

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

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

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

3. <u>Operational Excellence</u>

11. Outage Frequency - SAIFI – Target ≤ 1.20

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

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

12. Outage Duration – CAIDI – Target ≤ 115.5

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

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

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

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

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

14. Cyber Security – Target = 0

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

15. Physical Security – Target = 0

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

4. <u>Customer Experience</u>

16. Customer Service Appointments Kept – Target ≥ 95%

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

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

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

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

18. First Call Resolution – Target ≥ 84%

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

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

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

20. Storm Scorecard – Target ≥ 90

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

Earnings Goal -- Weighted at 25%

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

Operating Budget Goal – Weighted at 25%

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

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

Capital Budget Goal – Weighted at 5%

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

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

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

The 6 Capital Projects are as follows:

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

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

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

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

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

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

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

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

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

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

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

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

ROCKLAND ELECTRIC COMPANY
DIRECT TESTIMONY OF
DEPRECIATION PANEL

I. INTRODUCTION AND PURPOSE OF TESTIMONY

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

A. The Panel's direct testimony:

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

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

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

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

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

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

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

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

II. RECOMMENDED DEPRECIATION RATES AND DEPRECIATION STUDY

Q. Please define the concept of depreciation.

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

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

A. Yes.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

III. UNALLOCATED RESERVE AND NET SALVAGE ALLOWANCE

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

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

Q. Please discuss the unallocated accounts individually.

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

Q. Please describe the second unallocated depreciation reserve account.

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

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

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

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

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

Q. Please discuss the annual net salvage allowance.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

A. Yes, it does.

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

NJBPU Docket No. ____________

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

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

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

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

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

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

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

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

Q. Please briefly describe your educational and business experience.

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

(Banker) I received a Bachelor of Science degree in Electrical Engineering in 1991 from Clarkson University in Potsdam, New York and a Masters of Business Administration in 2000 from Iona College – Hagan School of Business, in New Rochelle, New York. I am a licensed Professional Engineer in the State of New York. I joined Orange and Rockland in 1990 and have held positions for Orange and Rockland as an underground Distribution and Transmission Engineer, as Divisional Field Engineer for the Electrical Operations Department, and my present position, which I assumed in 2005, as Chief Engineer of Distribution Engineering. This position oversees the planning, engineering and design of underground transmission and distribution projects included in the capital improvement budget.

(Coffey) I received a Bachelor of Science degree in Electrical Engineering from Manhattan College in 1988. I am a licensed Professional Engineer in the State of New York. I worked for one year at Burns and Roe Co. in Oradell, New Jersey as an Electrical Engineer prior to my arrival at Orange and Rockland in 1989. I have over 30 years of electrical engineering experience and have worked for Orange and Rockland for over 29 years. I have served in my current position since 2010. This position oversees the planning, engineering and design of transmission and substation projects included in the capital improvement budget.

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

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

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

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

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

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

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

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

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

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

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

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

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

A. Yes.

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

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

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

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

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

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

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

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

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

Q. Please explain both of these prioritization processes.

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

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

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

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

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

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

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

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

Test Year Major Capital Projects (through September 2019)

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

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

Reserve at Franklin Lakes Phase 1

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

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

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

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

Closter Breaker Replacements

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

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

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

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

Ringwood Breaker 983/984-78-2

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

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

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

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

Sweetwater Lane, Ringwood

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

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

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

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

<u>Additional Projects That Will Be Completed Post-Test Year (Through March 2020)</u>

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

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

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

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

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

Wyckoff Automation/Resiliency

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

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

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

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

Allendale Breaker T588-239 Replacement

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

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

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

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

<u>Old Tappan – Howard Drive</u>

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

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

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

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

Montvale – Main Street 4kV Conversion

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

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

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

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

Franklin Lakes – Old Mill Road Wyckoff Support

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

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

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

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

Oakland – Long Hill Road Hendrix

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

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

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

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

Orangeburg Road UG Circuit 30-7-13

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

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

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

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

Allendale 39-1 & 39-6 Reroute

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

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

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

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

Blanche Road UG Circuit 28-3-13

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

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

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

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

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

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

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

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

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

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

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

<u>Multi-Year Capital Projects (2019 – 2020)</u>

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

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

i. Distribution Reliability Blanket;

ii. Electric Distribution Blankets;

iii. Electric Meter and Transformer Blankets;

iv. Smart Grid Automation and Resiliency Program

v. U/G Circuit Relocation and Rebuild Blanket; and

vi. All Other Electric Blankets.

Each of these is described further below.

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

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

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

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

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

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

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

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

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

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

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

<u>Unit Charges Applicable to Extension of Lines and Facilities</u>

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

A. Yes.

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

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

Q. Please explain.

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

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

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

Q. How are these rates applied?

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

Storm Hardening Program

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

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

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

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

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

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

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

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

Selective Undergrounding

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

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

Overhead System Construction Projects

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

Harrington Park-Harriet Ave (Schraalenburgh to Bogert Mill)

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

Old Tappan-Old Tappan Road Reconductor

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

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

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

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

Oakland-Chuckanutt Drive Tie

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

Wyckoff-Godwin Avenue Mainline

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

Substation Flood Mitigation

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

Distribution Automation/Smart Grid Expansion

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

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

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

Danger Tree Program

Q. Please explain the Danger Tree Program

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

Major Storm Cost Reserve

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

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

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

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

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

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

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

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

Q. Does this conclude your testimony?

A. Yes, it does.

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

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

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

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

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

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

ROCKLAND ELECTRIC COMPANY
DIRECT TESTIMONY OF
ELECTRIC RATE PANEL

BPU Docket No. _____________

Table of Contents

I. INTRODUCTION

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

A. Cheryl Ruggiero, Lucy Villeta, and Shajan Jacob, 4 Irving Place, New York, New York 10003.

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

A. **(Ruggiero)** We are all employed by Consolidated Edison Company of New York, Inc. ("Con Edison"), the corporate affiliate of Rockland Electric Company ("RECO" or the "Company"). I am Department Manager of the Orange and Rockland ("O&R") Rate Design section of the Rate Engineering Department. I received a Bachelor of Science Degree in Electrical Engineering from Polytechnic University in 2000 and a Master of Business Administration Degree in Finance from Baruch College in 2009. In 2000, I began my employment with Con Edison as a Management Intern with rotational assignments in Electric Operations, Engineering Services, and Gas Operations. In July 2001, I accepted a position as an Associate Engineer - A in Distribution Engineering. In November 2005, I accepted a position as a Senior Analyst in Rate Engineering and have held titles of increasing responsibility. I was promoted to my current position in March 2013. I have submitted testimony before the New Jersey Board of Public Utilities ("BPU"), the Pennsylvania Public Utility Commission ("PAPUC") and the New York Public Service Commission ("NYPSC").

(Villeta) I am Section Manager of the Cost Analysis section of the Rate Engineering Department. I received a Bachelor of Business Administration Degree in Finance with a minor in Management Information Systems from Pace University in September 1989. In October 1989, I began my employment with Con Edison as a Management Intern with rotational assignments in Forecasting and Economic Analysis, Accounting Research and Procedures ("ARP") and Power Generation Services. In June 1990, I accepted my permanent assignment as an Associate Accountant in ARP. In 1995, I was promoted to Budget Analyst in Central Customer Service. In 1998, I was promoted to Senior Analyst in Customer Operations responsible for managing the Call Center and Service Center budget. In 2001, I was promoted to Financial Manager of Staten Island and Electric Services. I have been in my current position since November 2005. I have submitted testimony before the BPU, PAPUC, and NYPSC.

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

II. PURPOSE OF TESTIMONY

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

A. We will present:

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

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

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

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

(5) Proposed changes to standby rate provisions;

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

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

III. COMPANY-SPONSORED ECOS STUDY

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

A. The Company-sponsored ECOS study is contained in a document entitled "Rockland Electric Company – Company-sponsored Embedded Cost of Service Study – Year 2016" and identified as Exhibit P-8, Schedule 1.

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

A. Yes.

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

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

Q. What is the scope of the Company-sponsored ECOS study?

A. This ECOS study is for the electric distribution portion of the Company's operations. The revenues, expenses and rate base associated with Purchased Power and Transmission are excluded from this study.

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

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

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

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

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

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

Q. What is the total system rate of return shown in the Company-sponsored ECOS study?

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

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

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

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

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

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

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

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

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

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

Q. What do customer costs include?

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

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

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

Q. Please describe the functionalization and classification step.

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

Customer-related costs are fixed costs, which are caused by the presence of customers connected to the system. Revenue-related costs are general costs associated with conducting utility operations, such as the state income tax expense incurred by the Company.

Q. Please describe the allocation step.

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

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

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

IV. STAFF-ENDORSED ECOS STUDY

Q. Please describe the Staff-endorsed ECOS study.

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

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

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

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

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

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

A. No, it does not.

Q. Please explain.

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

Q. Please continue.

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

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

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

> Distribution facilities, from a design and operational perspective, are installed primarily to meet localized area loads. Distribution substations are designed to meet the maximum load from the distribution feeders emanating from the substation. Similarly, the distribution engineer designs primary and secondary distribution feeders so that sufficient conductor and transformer capacity is available to meet the customer's loads at the primary and secondary distribution service levels. Local area loads are the major factors in sizing distribution equipment. Consequently, customer-class non-coincident demands (NCPs) and individual customer maximum demands are the load characteristics that are normally used to allocate the demand component of distribution facilities.

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

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

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

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

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

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

A. The distribution revenue increase of $19,906,000, excluding sales and use tax ("SUT"), was provided by the Accounting Panel. This amount will be applied as an increase to distribution rates.

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

A. Before allocating the proposed distribution revenue increase among the various SCs, we realigned Test Year distribution revenues, excluding SUT, for each SC to address the deficiency and surplus indications from the Company-sponsored ECOS study. In doing so, the SCs were separated into the following groupings:

- SC No. 1 Residential Service and SC No. 5 Residential Space Heating Service;
- SC No. 2 General Service Secondary Non-Demand Billed;
- SC No. 2 General Service Secondary Demand Billed;
- SC No. 2 General Service Space Heating;
- SC No. 2 General Service Primary;
- SC No. 3 Residential Time-of-Day Heating Service;
- SC No. 4 Public Street Lighting Service;
- SC No. 6 Private Overhead Lighting Service – Dusk to Dawn;
- SC No. 6 Private Overhead Lighting Service – Energy Only;
- SC No. 7 Large General Time-Of-Day Service – Primary;
- SC No. 7 High Voltage Distribution; and
- SC No. 7 Space Heating.

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

A. Before making final decisions on the elimination of the deficiencies and surpluses, we considered the overall impacts of the realignment and distribution revenue increase by SC. After the realignment process, we allocated the distribution revenue increase among the SCs in proportion to the relative contribution made by each class to the realigned total Test Year distribution revenues. We then reviewed, by SC, the combined impact of eliminating a deficiency or surplus and the impact of the distribution revenue increase. We found that fully eliminating the deficiencies and surpluses, coupled with the distribution revenue increase, would result in large revenue impacts for the following classes: SC No. 1, SC No. 3, and SC No. 6 (Private Overhead Lighting Service - Dusk to Dawn). Therefore, we made mitigation adjustments, on an overall revenue neutral basis, to limit the class-specific distribution increase percentages to no more than 1.25 times the overall distribution increase percentage.

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

A. In addition to the mitigation adjustments described above, we implemented mitigation adjustments to limit the distribution revenue changes so that no class received a revenue decrease. SC No. 2 General Service Primary, SC No. 7 Large General Time-Of-Day Service – Primary, and SC No. 7 High Voltage Distribution were mitigated in this manner. The realignment of revenues, with the mitigation adjustments described above, will move the classes in the direction of more closely matching revenues with costs, while limiting the customer bill impacts associated with the changes.

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

A. In order to compute the proposed distribution rates, billing determinants by rate block must be used. These "by-block" billing determinants are available only for historic periods. Therefore, we restated the Test Year distribution revenue increases by class based on the twelve months ended March 31, 2019, *i.e.*, the historical period for which detailed billing data are available.

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

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

Q. Before applying the distribution revenue increases to each SC, did you make any revenue neutral changes?

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

A. Schedule 2 shows the calculation of the Company's proposed distribution rates, including SUT. Schedule 3 shows the effects that proposed rates will have on bills of SC Nos. 1, 2, 5 and 7 customers at various levels of consumption. Schedule 4 is a summary, by SC, of the Test Year sales, revenues at present and proposed rates, and the increase and percentage increase in revenues that will result from the proposed rate design. The revenues at proposed rates include an estimate of electric supply costs for retail access customers. As shown on Schedule 4, the overall percentage increase on total revenues is 9.6%.

VI. OTHER REVENUE ALLOCATION AND RATE DESIGN SCENARIOS

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

A. Yes. As explained above, the 2017 Rate Order required that RECO perform a rate design based on the Staff-endorsed ECOS study, while providing the Company with the flexibility to sponsor any ECOS study and rate design it determines appropriate.

Q. Did you produce a rate design based on the Staff-endorsed ECOS study? If so, what was the basis for this rate design?

A. Yes. Based on an approach similar to that discussed above, we produced rates and bill impacts for illustrative purposes using the results produced by the Staff-endorsed ECOS study. Briefly, we allocated the incremental distribution revenue requirement by realigning Test Year distribution revenues to reflect the full amount of the deficiency and surplus indications in accordance with the classes' cost responsibilities from the Staff-endorsed ECOS study. Based on the results of this process, we produced comparable schedules to Schedules 1 through 4 of Exhibit P-5. They are presented as Schedules 8 through 11 of Exhibit P-5.

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

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

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

A. Based on the results of the Staff-endorsed ECOS study, Schedule 8 contains illustrative distribution rates. Schedule 9 shows the calculation of the illustrative distribution rates, including SUT. Schedule 10 shows bill impacts using the Staff-endorsed ECOS study for SC Nos. 1, 2, 5 and 7 customers at various levels of consumption. Schedule 11 shows a summary, by SC, of the Test Year sales, revenues at present and proposed rates, and the increase and percentage increase in revenues that will result from the rate design using the results of the Staff-endorsed ECOS study.

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

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

VII. STANDBY RATES

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

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

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

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

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

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

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

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

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

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

A. Yes. Currently, SC No. 2 customers who take standby service are required to take service under SC No. 7 because there are no standby rate provisions outside of SC No. 7. Therefore, to allow customers to remain being served under SC No. 2 if they are to take standby rates, the Company proposes to move the standby rate provisions out of SC No. 7 and include them as a Rider to the tariff that will be applicable to demand-billed customers served under either SC No. 2 or SC No. 7.

VIII. LIGHTING SERVICE CLASSIFICATION CHANGES

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

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

Q. Please describe the new luminaires you are adding.

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

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

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

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

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

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

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

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

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

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

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

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

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

Q. Why did the Company propose this change?

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

IX. OTHER TARIFF CHANGES

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

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

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

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

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

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

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

A. Yes, Exhibit A to the Petition shows all tariff language changes and Exhibit B to the Petition shows these tariff language changes in redline/strikeout format. Exhibit C to the Petition contains two schedules showing side-by-side comparisons of present and proposed distribution rates included in the SCs and construction charges included in General Information Section No. 17.

Q. Does this conclude your direct testimony?

A. Yes, it does.

I. INTRODUCTION AND PURPOSE OF TESTIMONY

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

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

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

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

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

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

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

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

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

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

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

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

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

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

TCJA

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

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

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

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

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

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

REMOVAL COSTS

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

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

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

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

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

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

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

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

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

Q. How should flow through tax depreciation be calculated?

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

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

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

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

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

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

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

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

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

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

A. Yes, it does.

Q. Please state your name and business address.

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

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

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

Q. Please describe your educational background.

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

Q. Please describe your work experience.

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

Q. Please generally describe your current responsibilities.

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

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

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

Purpose

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

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

Background

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

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

Q. What is the purpose of the AMI metrics?

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

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

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

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

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

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

A. They include:

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

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

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

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

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

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

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

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

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

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

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

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

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

Prudency – AMI Program Benefits

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

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

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

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

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

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

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

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

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

(5) The AMI Program will provide a more accurate picture of its system's electrical performance which will benefit its planning and forecasting processes, as well as facilitating the incorporation of more DERs by using interval data from the AMI Program. The data from AMI will enable the Company to obtain, store and analyze actual 15-minute interval energy usage and power quality data from customer premises. By using this data as input for the Company’s Integrated System Model (“ISM”) and coupling it with the Company’s sophisticated analysis tools, RECO will realize a more accurate simulation of system electrical performance. This will benefit the Company’s electric planning and forecasting processes. Also, greater granularity within those processes improves integrated planning analysis to incorporate more DERs and potentially defer or eliminate, major capital expenditures. Simply knowing the actual voltages for every single meter along a circuit, including the very last meter on each circuit, allows for better management of the electric distribution system from the substation out to the last customer served.

(6) AMI metering will enable the Company to review the entire system as well as to monitor closely and model load characteristics, local voltage, and power quality. With

the AMI input, the entire system and generation profile can be integrated and reviewed for peaks, demand reduction, contingencies and monitoring (and future controlling) of generation sources such as solar and microgrids. Data can be summarized or aggregated to provide real-time operational awareness in the control center.

As these innovative technologies are implemented, AMI metering will enable the Company to monitor closely and model load characteristics and local voltage and power quality, so that these technologies are safely integrated with the use of smart devices in the field for the benefit of the consumer. Locational problems, even down to the secondary level, will be identified and resolved more quickly.

Q. Are there benefits associated with the automated connect/disconnect functionality of AMI and AMI meters?

A. Yes. The Company can employ this automated connect/disconnect functionality to support residential and small commercial AMI meters that have remote switch capability. The Company can now provide more timely connection or disconnection of service to those customers who are moving in or moving out of premises, thereby allowing for more timely service. Customers can now schedule connection and disconnection of service in advance with RECO. For example, a customer can call two weeks in advance of selling their home and request the specific date/time that they wish the service to be terminated. That request will sit in a pending state waiting for that date/time to arrive. When it does arrive, the automation of the AMI systems and communication network will communicate to that meter to open the switch disconnecting service. This not only provides an improved customer experience but also reduces unaccounted for usage that may occur on a “soft locked” meter while the Company awaits a new customer to contact RECO for service. Conversely, a customer who knows they will be purchasing a new home can contact RECO in advance and request service to be turned on for a certain date/time to coincide with their arrival at the home. RECO has encountered several examples, to date, where customers were on the phone with customer service representatives requesting service at a home and while standing in the home the representative was able to send a signal to those meters and turn the service on. These real-time, on demand, service activation are some of the best customer experiences a utility can provide. In addition, this functionality is being used to support collections work in the field. Customer meter technicians continue to make contact in person with customers who are eligible to have their service terminated for non-payment. However, if payment arrangements cannot be made the technician can now leave the premise instead of disconnecting the service. Once the technician completes the paperwork in the automated system a signal is sent over the air to open the switch in the meter thereby disconnecting service. Similarly, when payment is made by a customer who was disconnected for non-payment, an over the air signal is sent to the meter to close the switch in the meter thereby re-connecting service. While disconnection and reconnection of service for non-payment is not a pleasant interaction, this new remote functionality provides a marked customer experience improvement. For customers who make payment and need their service turned back on, they no longer need to wait for a technician to arrive at their home. The customer service representative can initiate an order that will send a signal to the meter to close the switch thereby providing power to the premise. As of March 31, 2019, the Company utilized remote switch functionality approximately 1,250 times.

Q. Please discuss the Company’s integration of the AMI system into the Company’s OMS, and the resulting benefits.

A. The Company completed the first round of AMI meter data integration into its OMS on September 30, 2018. This integration allows any and all AMI meters associated with an outage to be “pinged” by Company resources prior to dispatching crews to the field to investigate and effectuate repairs. The ability to “ping” a meter enhances the Company’s outage detection capability by providing confirmation that power is on or off at a particular premise. This information allows the Company to manage field crews more efficiently during restoration. During “Blue Sky” days and small-scale events from October 2018 through March 2019 the Company was able to use the “ping” capability to determine that power to customer locations was active 71 times. That is 71 distinct truck rolls that were avoided. As the Company becomes more skilled at performing a “ping” of AMI meters and the fact that the service territory will be fully deployed with AMI meters, the Company fully expects this number to grow. I would note that because the Company has not experienced a major storm since March 2018, RECO cannot yet report on the AMI system’s performance during such an event.

Q. Are there additional benefits from reduced truck rolls?

A. Yes, in addition to providing customers with accurate analysis of their power issues faster, there are environmental benefits (*i.e.*, reduced emissions) from not sending Company vehicles to those locations to determine the same result. In addition, Company vehicles can then be dispatched to locations where they can provide services to other customers.

Q. Has the Company performed any quantitative analysis of benefits and costs?

A. Yes. The Company provided a cost benefit analysis in the AMI Business Plan it submitted to the Board in the RECO AMI Proceeding, which analysis was referenced in the Board's AMI Order approving the AMI Program. That analysis reviewed project costs and benefits over a 20-year period and demonstrated benefits substantially exceeding costs.

Q. Have there been any changes to the Company's cost benefit analysis since the AMI Order (dated August 23, 2017) with regard to costs or benefits?

A. No. As indicated below, the actual project costs are well within the originally estimated project costs. The Amortization of Outmoded Assets is now $3.0 million less than what it was in 2016 but that is only due to legacy meter depreciation over the last three years. The Company continues to expect the level of benefits that were forecasted to occur in that analysis based on AMI deployment. As discussed above, the mass deployment of AMI meters is just now being completed such that there is no reason to adjust the projected benefits.

Q. What were the results of the cost benefit analysis previously submitted to the Board and referenced in its AMI Order?

A. Please see the Table 1 below showing costs and benefits in millions of dollars.

Table 1: Financial Highlights and Summary ($ in millions)

Business Case Financial View Over 20 Years	Costs
A. Costs (20 Year Total Costs)	(millions)
O&M Expense for AMI System	$12.0
Net Capital Depreciation Expense for AMI System	$12.6
Amortization of Outmoded Assets	$8.2
Sub-Total	$32.8
B. AMI Benefits (20 Year Total Benefits)	
AMI Cost Reduction Benefits	$65.0
Customer and Societal Benefits	$17.0
Sub-Total	$82.0
C. Total (20 Year Net Total)	
Benefits Less Costs	$49.2
Utility Simple Payback Period	7.2 years
Utility Discounted Payback Period	15.5 years

Prudency – Costs

Q. Please discuss the prudency of the costs the Company incurred to deploy the AMI Program.

A. As noted in the AMI Order (p. 4), the Company estimated that it would cost $16.5 million to deploy the AMI Program in the RECO service territory. The actual cost of the AMI program as of April 30, 2019 is $11,324,290 and the projected final cost is $16,200,000. The Company has implemented the AMI Program in an orderly and efficient fashion in accordance with the Implementation Plan, as demonstrated in the Quarterly Reports. The AMI Program's capital investment has been completed on schedule and under budget.

Q. What is the level of AMI expenditures are you projecting will be added to RECO's plant between April 2019 and March 2020?

A. As shown on Exhibit P-3, Schedule 12, I am projecting that approximately $1.6 million of AMI expenditures will be added to plant-in-service through March 2020. The balance of approximately $3.3 million (*i.e.,* $16.2 million less $11.3 million less $1.6 million), will be recorded on Orange and Rockland's books as part of "Joint Use Plant."

Legacy Meters

Q. What has the Board stated regarding the recovery of the costs of the legacy meters (*i.e*., those meters replaced by AMI meters)?

A. In the AMI Order (p. 19), the Board authorized the Company to defer, in a regulatory asset, the remaining net book value of the legacy meters. The Board directed the Company in its next base rate case, *i.e.*, this base rate case, to file testimony addressing the amount of the deferral for the legacy meters and a proposal for the amortization of the deferred costs.

Q. What is the amount of the Company’s remaining undepreciated, deferred investment in legacy meters?

A. As set forth in the direct testimony of the Depreciation Panel, the Company projects that upon completion of the AMI meter installation, the remaining unrecovered legacy meter costs will be approximately $5.2 million.

Q. Please explain why the Company should be authorized to recover the unrecovered legacy meter costs.

A. In the absence of the AMI Program, the costs of the legacy meters would have been recovered from customers in rates via depreciation. Indeed, the recovery of the investment in the legacy meters has been repeatedly approved in prior base rate cases. In the AMI Order, the Board authorized the Company to implement the AMI Program (and remove the existing meters), upon finding that the Program had the potential to "enable a host of benefits" (p. 20) and further the Energy Master Plan goals (p. 18). In order to implement the Board-approved AMI Program, and achieve the associated benefits, it was absolutely necessary to remove the legacy meters which resulted in the unrecovered legacy meter costs. As discussed above, the Company has demonstrated the undisputed benefits from and prudency of the AMI Program. Accordingly, the Company has included a proposal for the recovery of these legacy meter costs in this base rate filing.

Q. What is the Company proposing?

A. As discussed in the testimony of the Company's Depreciation Panel, the Company is proposing to amortize the net book value of the legacy meters over 15 years.

Opt-Out Fees

Q. Has the Company implemented the AMI opt-out fees approved by the Board in the AMI Order?

A. Yes. As authorized by the AMI Order (p. 21), the Company implemented the AMI opt-out fees via a tariff filing in June 2018. Specifically, the Company charges two fees related to customer opt-outs from the AMI Program: (1) a monthly meter reading fee of $15 monthly charge for those customers who choose not to have an AMI meter installed at their premise; and (2) a $45 meter change out fee for customers who opt-out after the AMI meter has been installed. The AMI Order authorized these fees after finding that the Company demonstrated they were in line with fees in other jurisdictions, and that the meter reading fee is consistent with basic causation principles since the fee would cover the incremental costs of manual meter reading. The Company does not propose to change the amount of either of these two fees in this rate filing.

Q. How much has the Company collected from these two fees?

A. Through March 31, 2019, the Company has collected a total of $36,225 from the opt-out fee. Through March 31, 2019, the Company has not had to perform meter change outs and has therefore collected $0 from the meter change out fee. The Accounting Panel discusses how these amounts are treated for ratemaking purposes.

Q. Should the Board continue to allow the Company to assess these two fees?

A. Definitely. The Company incurs actual costs associated with the provision of service to the customers against whom the fees are assessed that must be recovered. The monthly meter reading fee allows RECO to recover the incremental costs it incurs by manually reading the customer's meter. Similarly, the meter change-out fee allows RECO to recover the incremental costs that it incurs in changing out an AMI meter. Charging these fees to those very customers who require the Company to incur these incremental costs is consistent with fundamental cost causation principles.

Q. Does the current opt-out monthly manual meter reading fee of $15.00 cover the cost of the actual work associated with the manual meter reading?

A. No, the level of the opt-out fee is below the actual costs for the work of manual meter reading for the opt-out customers. The actual cost is now $17.00 per month per meter. This current higher cost of monthly manual meter reading is driven by increases in labor costs since the time of the issuance of the AMI Order. The determination of the $17.00 cost per read is based on meter reader labor costs per hour divided by six reads per hour.

Q. Is the Company requesting an increase in the monthly manual meter reading fee for opt-out customers?

A. No. The Company believes it would be reasonable to wait until a future rate filing to adjust the fee because the mass deployment of AMI meters is nearing completion. The Company believes it would be better to review this charge after meter readers have had additional experience focusing on reading the final number of opt-out meters monthly following removal of legacy meters and deployment of AMI meters.

Q. How many RECO customers have opted-out of the AMI Program?

A. As of March 31, 2019, 644 accounts have opted-out of RECO’s AMI Program.

Q. Does that conclude your direct testimony at this time?

A. Yes, it does.

ROCKLAND ELECTRIC COMPANY
RATE OF RETURN

TABLE OF CONTENTS

PAGE

BEFORE THE
NEW JERSEY BOARD OF PUBLIC UTILITIES

ROCKLAND ELECTRIC COMPANY

BPU DOCKET NO. __________

DIRECT TESTIMONY OF JAMES H. VANDER WEIDE
ON BEHALF OF
ROCKLAND ELECTRIC COMPANY

I. INTRODUCTION AND PURPOSE

Q. Please state your name, title, and business address.

A. My name is James H. Vander Weide. I am President of Financial Strategy Associates, a firm that provides strategic and financial consulting services to business clients. My business address is 3606 Stoneybrook Drive, Durham, North Carolina 27705.

Q. Please describe your educational background and prior academic experience.

A. I graduated from Cornell University with a Bachelor's Degree in Economics and from Northwestern University with a Ph.D. in Finance. After joining the faculty of the School of Business at Duke University, I was named Assistant Professor, Associate Professor, Professor, and then Research Professor. I have published research in the areas of finance and economics and taught courses in these fields at Duke for more than thirty-five years. I am now retired from my teaching duties at Duke. A summary of my research, teaching, and other professional experience is presented in Appendix 1.

Q. Have you previously testified on financial or economic issues?

A. Yes. As an expert on financial and economic theory and practice, I have participated in more than five hundred regulatory and legal proceedings before the public service commissions of forty-five states and four Canadian provinces, the United States Congress, the Federal Energy Regulatory Commission, the National Energy Board (Canada), the Federal Communications Commission, the Canadian Radio-Television and Telecommunications Commission, the National Telecommunications and Information Administration, the insurance commissions of five states, the Iowa State Board of Tax Review, the National Association of Securities Dealers, and the North Carolina Property Tax Commission. In addition, I have prepared expert testimony in proceedings before the United States District Court for the District of Nebraska; the United States District Court for the District of New Hampshire; the United States District Court for the District of Northern Illinois; the United States District Court for the Eastern District of North Carolina; the United States District Court for the Northern District of California; the United States District Court for the Eastern District of Michigan; the United States Bankruptcy Court for the Southern District of West Virginia; the Montana Second Judicial District Court, Silver Bow County; the Superior Court, North Carolina; and the Supreme Court of the State of New York.

Q. What is the purpose of your testimony in this proceeding?

A. I have been asked by Rockland Electric Company ("RECO" or the "Company") to prepare an independent appraisal of the required rate of return on equity for the Company's regulated utility operations in New Jersey and to recommend an allowed rate of return on equity ("ROE") for these operations that is fair, that allows the Company to attract capital on reasonable terms, and that allows the Company to maintain its financial integrity. RECO is a wholly-owned subsidiary of Orange and Rockland Utilities, Inc. ("O&R"), and O&R is a wholly-owned subsidiary of Consolidated Edison, Inc. ("CEI").

II. SUMMARY OF TESTIMONY

Q. How do you estimate RECO's required rate of return on equity?

A. I estimate RECO's required rate of return equity by: (1) applying several standard cost of equity estimation methods to financial data for a proxy group of electric utilities of comparable risk; and (2) calculating the average expected rate of return on book equity for the group of electric utilities.

Q. Why do you apply cost of equity methods to a proxy group of comparable risk utilities rather than solely to the Company?

A. I apply my cost of equity methods to a proxy group of comparable risk utilities because: (1) the Company is not publicly-traded; and (2) standard cost of equity methods such as the discounted cash flow ("DCF"), risk premium, and capital asset pricing model ("CAPM") require inputs of quantities that are not easily measured. Because these inputs can only be estimated, there is naturally some degree of uncertainty surrounding the estimate of the cost of equity for each company. However, the uncertainty in the estimate of the cost of equity for an individual company can be greatly reduced by applying cost of equity methods to a large sample of comparable companies. Intuitively, unusually high estimates for some individual companies are offset by unusually low estimates for other individual companies. Thus, financial economists invariably apply cost of equity methods to one or more proxy groups of comparable companies. In utility regulation, the practice of using comparable companies, called the comparable company approach, is further supported by the United States Supreme Court standard that the utility should be allowed to earn a return on its investment that is commensurate with returns being earned on other investments of comparable risk.[1] I note that the Board has previously accepted the practice of calculating the Company's required rate of return on equity by applying cost of equity methods to a proxy group of comparable risk utilities in the Company's prior rate cases (for example, BPU Docket No. ER16050428 and BPU Docket No. ER1311135).

Q. Why do you believe it is important to use more than one analytical approach to estimate the Company's cost of equity?

A. Because the cost of equity is not directly observable, it must be estimated based on both quantitative and qualitative information. When faced with the task of estimating the cost of equity, analysts and investors gather and evaluate as much relevant data as reasonably can be analyzed. As a result, a number of models have been developed to estimate the cost of equity. However, as a practical matter, all models available for estimating the cost of equity are subject to limiting assumptions or other methodological constraints.

Financial models simply are tools to be used in the ROE estimation process, and strict adherence to any single approach, or to the specific results of any single approach, can lead to flawed or misleading conclusions. This position

---

[1] *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia,* 262 U.S. 679 (1923) ("Bluefield Water Works")*; Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S. 591 (1944) ("Hope Natural Gas")

is consistent with the finding in both *Bluefield Water Works* and *Hope Natural Gas* that it is the analytical result, as opposed to the methodology, that is controlling in arriving at ROE determinations. Thus, a reasonable ROE estimate appropriately considers alternate methodologies and the reasonableness of their individual and collective results.

Consequently, I believe it is prudent and appropriate to use multiple methodologies in order to reduce the uncertainty that may be associated with the assumptions and inputs of any single approach. It is further appropriate to apply reasoned judgment in considering the results generated by each individual approach.

Q. What required rate of return on equity do you find for the utility operations of RECO in this proceeding?

A. On the basis of my studies, I find that the required rate of return on equity for the utility operations of RECO is 10.4 percent. This conclusion is based on my application of standard cost of equity estimation techniques, including the DCF model and the CAPM, to a proxy group of electric utilities of comparable risk and my calculation of the average expected rate of return on book equity for that group of electric utilities.

Q. Do you have exhibits accompanying your testimony?

A. Yes. I have prepared or supervised the preparation of Exhibit ___(JVW-1), which consists of ten schedules and five appendices that accompany my direct testimony.

III. ECONOMIC AND LEGAL PRINCIPLES

Q. What is the economic definition of the cost of capital?

A. Economists define the cost of capital as the return investors expect to receive on alternative investments of comparable risk.

Q. What role does the cost of capital play in the allocation of capital in the capital markets?

A. The cost of capital is a hurdle rate, or cut-off rate, for investment in a company or project. Investors will only invest in a company or project if they expect to earn a return on their investment that is at least as large as the return they expect to receive on other investments of comparable risk.

Q. Do all investors have the same position in the company?

A. No. Debt investors have a fixed claim on a company's assets and income that must be paid prior to any payment to the company's equity investors. Because the company's equity investors have only a residual claim on the company's assets and income, equity investments are riskier than debt investments. Thus, the cost of equity exceeds the cost of debt.

Q. What is the overall or average cost of capital?

A. The overall or average cost of capital is a weighted average of the cost of debt and cost of equity, where the weights are the percentages of debt and equity in a company's capital structure.

Q. Can you illustrate the calculation of the overall or weighted average cost of capital?

A. Yes. Assume that the cost of debt is 7 percent, the cost of equity is 13 percent, and the percentages of debt and equity in the company's capital structure are 50 percent and 50 percent, respectively. Then the weighted average cost of capital is expressed by 0.50 times 7 percent plus 0.50 times 13 percent, or 10.0 percent.

Q. How do economists define the cost of equity?

A. Economists define the cost of equity as the return investors expect to receive on alternative equity investments of comparable risk. Because the return on an equity investment of comparable risk is not a contractual return, the cost of equity is more difficult to measure than the cost of debt. However, as I have already noted, there is agreement among economists that the cost of equity is greater than the cost of debt. There is also agreement among economists that the cost of equity, like the cost of debt, is both forward looking and market based.

Q. How do economists measure the percentages of debt and equity in a company's capital structure?

A. Economists measure the percentages of debt and equity in a company's capital structure by first calculating the market value of the company's debt and the market value of its equity. Economists then calculate the percentage of debt by the ratio of the market value of debt to the combined market value of debt and equity, and the percentage of equity by the ratio of the market value of equity to the combined market value of debt and equity. For example, if a company's debt has a market value of $25 million and its equity has a market value of

$75 million, then its total market capitalization is $100 million, and its capital structure contains 25 percent debt and 75 percent equity.

Q. Why do economists measure a company's capital structure in terms of the market values of its debt and equity?

A. Economists measure a company's capital structure in terms of the market values of its debt and equity because: (1) the weighted average cost of capital is defined as the return investors expect to earn on a portfolio of the company's debt and equity securities; (2) investors measure the expected return and risk on their portfolios using market value weights, not book value weights; and (3) market values are the best measures of the amounts of debt and equity investors have invested in the company on a going forward basis.

Q. Why do investors measure the expected return and risk on their investment portfolios using market value weights rather than book value weights?

A. Investors measure the expected return and risk on their investment portfolios using market value weights because: (1) the expected return on a portfolio is calculated by comparing the expected value of the portfolio at the end of the investment period to its current value; (2) the risk of a portfolio is calculated by examining the variability of the end-of-period return on the portfolio around the expected value; and (3) market values are the best measure of the current value of the portfolio. From the investor's point of view, the historical cost, or book value of their investment, is generally a poor indicator of the portfolio's current value.

Q. Is the economic definition of the weighted average cost of capital consistent with regulators' traditional definition of the average cost of capital?

A. No. The economic definition of the weighted average cost of capital is based on the market costs of debt and equity, the market value percentages of debt and equity in a company's capital structure, and the future expected risk of investing in the company. In contrast, regulators have traditionally defined the weighted average cost of capital using the embedded cost of debt and the book or accounting values of debt and equity shown on a company's balance sheet. A company's market value capital structure generally differs from its book value capital structure because the market value capital structure reflects the current values of the company's debt and equity in the capital markets, whereas the company's book value capital structure reflects the values of the company's debt and equity based on historical accounting costs.

Q. Will investors have an opportunity to earn a fair return on the value of their equity investment in the company if regulators calculate the weighted average cost of capital using the book value of equity in the company's capital structure?

A. No. Investors will only have an opportunity to earn a fair return on the value of their equity investment if regulators either calculate the weighted average cost of capital using the market value of equity in the company's capital structure or adjust the cost of equity for the difference in the financial risk reflected in the market value capital structures of the proxy companies and the financial risk reflected in the company's rate making capital structure.

Q. Are the economic principles regarding the fair return for capital recognized in any United States Supreme court cases?

A. Yes. These economic principles, relating to the supply of and demand for capital, are recognized in two United States Supreme Court cases: (1) *Bluefield Water Works*; and (2) *Hope Natural Gas Co*. In the *Bluefield Water Works* case, the Court stated:

> A public utility is entitled to such rates as will permit it to earn a return upon the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit, and enable it to raise the money necessary for the proper discharge of its public duties. [*Bluefield Water Works and Improvement Co. v. Public Service Comm'n.* 262 U.S. 679, 692 (1923).]

The Supreme Court recognizes here that: (1) a regulated company cannot remain financially sound unless the return it is allowed to earn on the value of its property is at least equal to the cost of capital (the principle relating to the demand for capital); and (2) a regulated company will not be able to attract capital if it does not offer investors an opportunity to earn a return on their investment equal to the return they expect to earn on other investments of similar risk (the principle relating to the supply of capital).

In the *Hope Natural Gas* case, the Supreme Court reiterates the financial soundness and capital attraction principles of the *Bluefield Water Works* case:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock... By that standard the return to the equity owner should be commensurate with returns on investments

> in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. [*Federal Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 591, 603 (1944).]

The Supreme Court recognizes that the fair rate of return on equity should be: (1) comparable to returns investors expect to earn on other investments of similar risk; (2) sufficient to assure confidence in the company's financial integrity; and (3) adequate to maintain and support the company's credit and to attract capital.

IV. RECO'S REQUIRED RATE OF RETURN ON EQUITY

Q. How do you estimate the required rate of return on equity for RECO's electric utility operations?

A. I estimate RECO's required rate of return on equity by applying several cost of equity estimation methods to a group of comparable-risk electric utilities and by calculating the average expected rate of return on book equity for the comparable group of electric utilities.

Q. What methods do you use to estimate the cost of equity for RECO's electric utility operations?

A. I use the DCF model and the CAPM. The DCF model assumes that the current market price of a company's stock is equal to the discounted value of all expected future cash flows. The CAPM assumes that the investor's required rate of return on equity is equal to the expected risk-free rate of interest plus the product of a company-specific risk factor, beta, and the expected risk premium on the market portfolio.

Q. How do you use the comparable earnings method to calculate RECO's required rate of return on equity?

A. I use the comparable earnings method to estimate RECO's required rate of return on equity by calculating the average expected rate of return on book equity for a comparable group of electric utilities.

Q. Is the comparable earnings method consistent with the United States Supreme Court's fair rate of return standard?

A. Yes. The United States Supreme Court states in the *Hope Natural Gas* case that the "return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks." [*Federal Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 591, 603 (1944).] This language is consistent with both a capital attraction standard, as measured by the cost of equity, and a comparable earnings standard, as measured by calculating the expected rate of return on equity for a group of comparable-risk companies.

A. THE DISCOUNTED CASH FLOW MODEL

Q. Please describe the DCF model.

A. The DCF model is based on the assumption that investors value an asset because they expect to receive a sequence of cash flows from owning the asset. Thus, investors value an investment in a bond because they expect to receive a sequence of semi-annual coupon payments over the life of the bond and a terminal payment equal to the bond's face value at the time the bond matures. Likewise, investors value an investment in a company's stock because they expect to receive a sequence of dividend payments and, perhaps, expect to sell the stock at a higher price sometime in the future.

A second fundamental principle of the DCF model is that investors value a dollar received in the future less than a dollar received today. A future dollar is valued less than a current dollar because investors could invest a current dollar in an interest earning account and increase their wealth. This principle is called the time value of money.

Applying the two fundamental DCF principles noted above to an investment in a bond leads to the conclusion that investors value their investment in the bond on the basis of the present value of the bond's future cash flows. Thus, the price of the bond should be equal to:

EQUATION 1

$$P_B = \frac{C}{(1+i)} + \frac{C}{(1+i)^2} + \ldots + \frac{C+F}{(1+i)^n}$$

where:

P_B	=	Bond price;
C	=	Cash value of the coupon payment (assumed for notational convenience to occur annually rather than semi-annually);
F	=	Face value of the bond;
i	=	The rate of interest the investor could earn by investing his money in an alternative bond of equal risk; and
n	=	The number of periods before the bond matures.

Applying these same principles to an investment in a company's stock suggests that the price of the stock should be equal to:

EQUATION 2

$$P_s = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_n + P_n}{(1+k)^n}$$

where:

P_S	=	Current price of the company's stock;
$D_1, D_2 \ldots D_n$	=	Expected annual dividend per share on the company's stock;
P_n	=	Price per share of stock at the time the investor expects to sell the stock; and
k	=	Return the investor expects to earn on alternative investments of the same risk, i.e., the investor's required rate of return.

Equation (2) is frequently called the annual discounted cash flow model of stock valuation. Assuming that dividends grow at a constant annual rate, g, this equation can be solved for k, the cost of equity. The resulting cost of equity equation is $k = D_1/P_s + g$, where k is the cost of equity, D_1 is the expected next period annual dividend, P_s is the current price of the stock, and g is the constant annual growth rate in earnings, dividends, and book value per share. The term D_1/P_s is called the expected dividend yield component of the annual DCF model, and the term g is called the expected growth component of the annual DCF model.

Q. Are you recommending that the annual DCF model be used to estimate the cost of equity for RECO's electric utility operations?

A. No. The DCF model assumes that a company's stock price is equal to the present discounted value of all expected future dividends. The annual DCF model is only a correct expression of the present value of future dividends if dividends are paid annually at the end of each year. Because the companies in my comparable group all pay dividends quarterly, the current market price that investors are willing to pay reflects the expected quarterly receipt of dividends. Therefore, a quarterly DCF model should be used to estimate the cost of equity for these companies. The quarterly DCF model differs from the annual DCF model in that it expresses a company's price as the present value of a quarterly stream of dividend payments. A complete analysis of the implications of the quarterly payment of dividends on the DCF model is provided in Appendix 2. For the reasons cited there, I employed the quarterly DCF model throughout my calculations, even though the results of the quarterly DCF model for my companies are approximately equal to the results of a properly applied annual DCF model.

Q. Please describe the quarterly DCF model you use.

A. The quarterly DCF model I use is described on Schedule 1 and in Appendix 2. The quarterly DCF equation shows that the cost of equity is: the sum of the future expected dividend yield and the growth rate, where the dividend in the dividend yield is the equivalent future value of the four quarterly dividends at the end of the year, and the growth rate is the expected growth in dividends or earnings per share.

Q. How do you estimate the quarterly dividend payments in your quarterly DCF model?

A. The quarterly DCF model requires an estimate of the dividends, d_1, d_2, d_3, and d_4, investors expect to receive over the next four quarters. I estimate the next four quarterly dividends by multiplying the previous four quarterly dividends by (1 + g), where *g* is the expected growth rate.

Q. Can you illustrate how you estimate the next four quarterly dividends with data for a specific company in your proxy group of electric utilities?

A. Yes. In the case of Alliant Energy, the first electric utility company shown in Schedule 1, the last four quarterly dividends are each equal to 0.335 and the expected growth rate is 6.9 percent. Thus dividends, d_1, d_2, d_3, and d_4 are equal to 0.358 [0.335 x (1 + 0.069) = 0.358]. (As noted previously, the logic underlying this procedure is described in Appendix 2.)

Q. How do you estimate the growth component of the quarterly DCF model?

A. I use the I/B/E/S analysts' estimates of future earnings per share ("EPS") growth reported by Refinitiv (formerly Thomson Reuters).

Q. What are the analysts' estimates of future EPS growth?

A. As part of their research, financial analysts working at Wall Street companies periodically estimate EPS growth for each company they follow. The EPS forecasts for each company are then published. Investors who are contemplating purchasing or selling shares in individual companies review the forecasts. These estimates represent three- to five-year forecasts of EPS growth.

Q. What is I/B/E/S?

A. I/B/E/S is a database that reports analysts' EPS growth forecasts for a broad group of companies. The forecasts are expressed in terms of a mean forecast and a standard deviation of forecast for each company. Investors use the mean forecast as an estimate of future company performance.

Q. Why do you use the I/B/E/S growth estimates?

A. The I/B/E/S growth rates: (1) are widely circulated in the financial community, (2) include the projections of reputable financial analysts who develop estimates of future EPS growth, (3) are reported on a timely basis to investors, and (4) are widely used by institutional and other investors.

Q. Why do you rely on analysts' projections of future EPS growth in estimating the investors' expected growth rate rather than looking at past historical growth rates?

A. I rely on analysts' projections of future EPS growth because there is considerable empirical evidence that investors use analysts' EPS growth forecasts to estimate future earnings growth.

Q. Have you performed any studies concerning the use of analysts' forecasts as an estimate of investors' expected growth rate, g?

A. Yes. I prepared a study with Willard T. Carleton, Professor Emeritus of Finance at the University of Arizona, which is described in a paper entitled "Investor Growth Expectations and Stock Prices: the Analysts versus History," published in the Spring 1988 edition of *The Journal of Portfolio Management*.

Q. Please summarize the results of your study.

A. First, we performed a correlation analysis to identify the historically-oriented growth rates which best described a company's stock price. Then we did a regression study comparing the historical growth rates with the average I/B/E/S analysts' forecasts. In every case, the regression equations containing the average of analysts' forecasts statistically outperformed the regression equations containing the historical growth estimates. These results are consistent with those found by Cragg and Malkiel, the early major research in this area (John G. Cragg and Burton G. Malkiel, *Expectations and the Structure of Share Prices*, University of Chicago Press, 1982). These results are also consistent with the hypothesis that investors use analysts' forecasts, rather than historically-oriented or sustainable growth calculations, in making stock buy and sell decisions. They provide overwhelming evidence that the analysts' forecasts of future growth are superior to historically-oriented or sustainable growth measures in predicting a company's stock price. Researchers at State Street Financial Advisors updated my study in 2004, and their results continue to confirm that analysts' growth forecasts are superior to historically-oriented growth measures in predicting a company's stock price.

Q. What stock prices do you use in your DCF model?

A. I use a simple average of the monthly high and low stock prices for each company for the three-month period ended January 2019. These high and low stock prices were obtained from Thomson Reuters.

Q. Why do you use the three-month average stock price in applying the DCF method?

A. I use the three-month average stock price in applying the DCF method because stock prices fluctuate daily, while financial analysts' forecasts for a given company are generally changed less frequently, often on a quarterly basis. Thus, to match the stock price with an earnings forecast, it is appropriate to use average stock prices over a three-month period.

Q. Do you include an allowance for flotation costs in your DCF analysis?

A. Yes. I include a five percent allowance for flotation costs in my DCF calculations.

Q. Please explain your inclusion of flotation costs.

A. All companies that have sold securities in the capital markets have incurred some level of flotation costs, including underwriters' commissions, legal fees, and printing expenses, for example. These costs are withheld from the proceeds of the stock sale or are paid separately, and must be recovered over the life of the equity issue. Costs vary depending upon the size of the issue, the type of registration method used and other factors, but in general these costs range between three percent and five percent of the proceeds from the issue [see Lee, Inmoo, Scott Lochhead, Jay Ritter, and Quanshui Zhao, "The Costs of Raising Capital," *The Journal of Financial Research*, Vol. XIX No 1 (Spring 1996), 59-74, and Clifford W. Smith, "Alternative Methods for Raising Capital," *Journal of Financial Economics* 5 (1977) 273-307]. In addition to these costs, for large equity issues (in relation to outstanding equity shares), there is likely to be a decline in price associated with the sale of shares to the public. On average, the decline due to market pressure has been estimated at two percent to three percent [see Richard H. Pettway, "The Effects of New Equity Sales upon Utility Share Prices," *Public Utilities Fortnightly*, May 10, 1984, 35—39]. Thus, the total flotation cost, including both issuance expense and stock price decline, generally ranges from five percent to eight percent of the proceeds of an equity issue. I believe a combined five percent allowance for flotation costs is a conservative estimate that should be used in applying the DCF model in these proceedings. A complete explanation of the need for flotation costs is contained in Appendix 3.

Q. How do you select your electric utility proxy company group?

A. I select all the electric utilities followed by Value Line that: (1) have an investment-grade bond rating; (2) paid dividends during every quarter of the last two years; (3) did not decrease dividends during any quarter of the past two years; (4) have a positive I/B/E/S long-term growth forecast; and (5) are not the subject of a merger offer that has not been completed. I also note that each of the utilities included in my comparable group has a Value Line Safety Rank of 1, 2, or 3.

Q. Why do you eliminate companies that have either decreased or eliminated their dividend in the past two years?

A. The DCF model requires the assumption that dividends will grow at a constant rate into the indefinite future. If a company has either decreased or eliminated its dividend in recent years, the assumption that the company's dividend will grow at the same rate into the indefinite future becomes questionable.

Q. Why do you eliminate companies that are the subject of a merger offer that has not been completed?

A. A merger announcement can sometimes have a significant impact on a company's stock price because of anticipated merger-related cost savings and new market opportunities. Analysts' growth forecasts, on the other hand, are necessarily related to companies as they currently exist, and do not reflect investors' views of the potential cost savings and new market opportunities associated with mergers. The use of a stock price that includes the value of potential mergers in conjunction with growth forecasts that do not include the growth enhancing prospects of potential mergers may distort the DCF model result.

Q. Please summarize the results of your application of the DCF model to your electric utility group.

A. As shown on Schedule 1, I obtain an average DCF result of 10.1 percent for my electric utility proxy company group.

B. CAPITAL ASSET PRICING MODEL

Q. What is the CAPM?

A. The CAPM is an equilibrium model of the security markets in which the expected or required return on a given security is equal to the risk-free rate of interest, plus the company equity "beta," times the market risk premium:

Cost of equity = Risk-free rate + Equity beta x Market risk premium

The risk-free rate in this equation is the expected rate of return on a risk-free government security, the equity beta is a measure of the company's risk relative to the market as a whole, and the market risk premium is the premium investors require to invest in the market basket of all securities compared to the risk-free security.

Q. How do you use the CAPM to estimate the cost of equity for your proxy companies?

A. The CAPM requires an estimate of the risk-free rate, the company-specific risk factor or beta, and the expected return on the market portfolio. For my estimate of the risk-free rate, I use a forecasted yield to maturity on 20-year Treasury bonds of 3.8 percent, obtained using data from Value Line and the United States

Energy Information Administration ("EIA"). For my estimate of the company-specific risk, or beta, I use both the current average 0.60 Value Line beta for the Value Line electric utilities and the 0.89 beta estimated from the relationship between the historical risk premium on utilities and the historical risk premium on the market portfolio. For my estimate of the expected risk premium on the market portfolio, I use two approaches. First, I estimate the risk premium on the market portfolio using historical risk premium data reported in the *2018 Valuation Handbook* for the years 1926 through 2017, data which are consistent with the data previously reported by Ibbotson® SBBI®. Second, I estimate the risk premium on the market portfolio from the difference between the DCF cost of equity for the S&P 500 and the forecasted yield to maturity on 20-year Treasury bonds.

Q. How do you obtain the forecasted yield to maturity on 20-year Treasury bonds?

A. I obtain the forecasted yield to maturity on 20-year Treasury bonds using data from Value Line and EIA. Value Line forecasts a yield on 10-year Treasury notes equal to 3.5 percent. The spread at January 2019 between the average yield on 10-year Treasury notes (2.71 percent) and 20-year Treasury bonds (2.89 percent) is 18 basis points. Adding 18 basis points to Value Line's 3.5 percent forecasted yield on 10-year Treasury notes produces a forecasted yield of 3.68 percent for 20-year Treasury bonds (see Value Line Investment Survey, Selection & Opinion, November 30, 2018). EIA forecasts a yield of 3.73 percent on 10-year Treasury notes. Adding the 18 basis point spread between 10-year Treasury notes and 20-

year Treasury bonds to the EIA forecast of 3.73 percent for 10-year Treasury notes produces an EIA forecast for 20-year Treasury bonds equal to 3.9 percent. The average of the forecasts is 3.8 percent (3.7 percent using Value Line data and 3.9 percent using EIA data).

1. Historical CAPM

Q. How do you estimate the expected risk premium on the market portfolio using historical risk premium data developed by Ibbotson® SBBI®?

A. I estimate the expected risk premium on the market portfolio by calculating the difference between the arithmetic mean total return on the S&P 500 from 1926 to 2018 (12.06 percent) and the average income return on 20-year U.S. Treasury bonds over the same period (4.99 percent). Thus, my historical risk premium method produces a risk premium of 7.07 percent (12.06 – 4.99 = 7.07).

Q. Why do you recommend that the risk premium on the market portfolio be estimated using the arithmetic mean return on the S&P 500?

A. I recommend that the risk premium on the market portfolio be estimated using the arithmetic mean return on the S&P 500 because, for an investment which has an uncertain outcome, the arithmetic mean is the best historically-based measure of the return investors expect to receive in the future. A discussion of the importance of using arithmetic mean returns in the context of CAPM or risk premium studies is contained in Schedule 2.

Q. Why do you recommend that the risk premium on the market portfolio be measured using the income return on 20-year Treasury bonds rather than the total return on these bonds?

A. As discussed above, the CAPM requires an estimate of the risk-free rate of interest. When Treasury bonds are issued, the income return on the bond is risk free, but the total return, which includes both income and capital gains or losses, is not. Thus, the income return should be used in the CAPM because it is only the income return that is risk free.

Q. Is there any evidence from the finance literature that the application of the historical CAPM may underestimate the cost of equity?

A. Yes. There is substantial evidence that: (1) the historical CAPM tends to underestimate the cost of equity for companies whose equity beta is less than 1.0; and (2) the CAPM is less reliable the further the estimated beta is from 1.0.

Q. What is the evidence that the CAPM tends to underestimate the cost of equity for companies with betas less than 1.0 and is less reliable the further the estimated beta is from 1.0?

A. The original evidence that the unadjusted CAPM tends to underestimate the cost of equity for companies whose equity beta is less than 1.0 and is less reliable the further the estimated beta is from 1.0 was presented in a paper by Black, Jensen, and Scholes, "The Capital Asset Pricing Model: Some Empirical Tests." Numerous subsequent papers have validated the Black, Jensen, and Scholes findings, including those by Litzenberger and Ramaswamy (1979), Banz (1981), Fama and French (1992), Fama and French (2004), Fama and MacBeth (1973), and Jegadeesh and Titman (1993).[2]

---

[2] Fischer Black, Michael C. Jensen, and Myron Scholes, "The Capital Asset Pricing Model: Some Empirical Tests," in *Studies in the Theory of Capital Markets*, M. Jensen, Ed. New York: Praeger, 1972; Eugene Fama and James MacBeth, "Risk, Return, and Equilibrium: Empirical Tests," *Journal of Political Economy* 81 (1973), pp. 607-36; Robert Litzenberger and Krishna Ramaswamy, "The Effect of Personal Taxes and

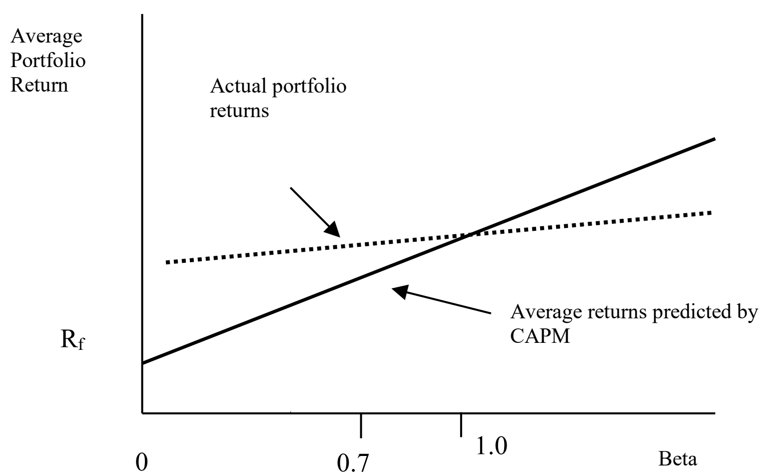
Q. Can you briefly summarize these articles?

A. Yes. The CAPM conjectures that security returns increase with increases in security betas in line with the equation:

$$ER_i = R_f + \beta_i \left[ER_m - R_f \right],$$

where ER_i is the expected return on security or portfolio i, R_f is the risk-free rate, $ER_m - R_f$ is the expected risk premium on the market portfolio, and β_i is a measure of the risk of investing in security or portfolio i (see Figure 1 below).

FIGURE 1
AVERAGE RETURNS COMPARED TO BETA
FOR PORTFOLIOS FORMED ON PRIOR BETA



Financial scholars have studied the relationship between estimated portfolio betas and the achieved returns on the underlying portfolio of securities to test whether the CAPM correctly predicts achieved returns in the marketplace. They find that

---

Dividends on Capital Asset Prices: Theory and Empirical Evidence," *Journal of Financial Economics* 7 (1979), pp. 163-95.; Rolf Banz, "The Relationship between Return and Market Value of Common Stocks," *Journal of Financial Economics* (March 1981), pp. 3-18; Eugene F. Fama and Kenneth R. French, "The Cross-Section of Expected Returns," *Journal of Finance* (June 1992), 47:2, pp. 427-465; Eugene F. Fama and Kenneth R. French, "The Capital Asset Pricing Model: Theory and Evidence," *The Journal of Economic Perspectives* (Summer 2004), 18:3, pp. 25 – 46; Narasimhan Jegadeesh and Sheridan Titman, "Returns to Buying Winners and Selling Losers: Implications for Stock Market Efficiency," *The Journal of Finance*, Vol. 48, No. 1. (Mar., 1993), pp. 65-91.

the relationship between returns and betas is inconsistent with the relationship posited by the CAPM. As described in Fama and French (1992) and Fama and French (2004), the actual relationship between portfolio betas and returns is shown by the dotted line in Figure 1 above. Although financial scholars disagree on the reasons why the return/beta relationship looks more like the dotted line in Figure 1 than the solid line, they generally agree that the dotted line lies above the solid line for portfolios with betas less than 1.0 and below the straight line for portfolios with betas greater than 1.0. Thus, in practice, scholars generally agree that the CAPM underestimates portfolio returns for companies with betas less than 1.0, and overestimates portfolio returns for portfolios with betas greater than 1.0.

Q. Do you have additional evidence that the CAPM tends to underestimate the cost of equity for utilities with average betas less than 1.0?

A. Yes. As shown in Schedule 3, over the period 1937 to 2019, investors in the S&P Utilities Stock Index have earned a risk premium over the yield on long-term Treasury bonds equal to 5.46 percent, while investors in the S&P 500 have earned a risk premium over the yield on long-term Treasury bonds equal to 6.11 percent. According to the CAPM, investors in utility stocks should expect to earn a risk premium over the yield on long-term Treasury securities equal to the average utility beta times the expected risk premium on the S&P 500. Thus, the ratio of the risk premium on the utility portfolio to the risk premium on the S&P 500 should equal the utility beta. However, the average utility beta at the time of my studies is approximately 0.60, whereas the historical ratio of the utility risk premium to the S&P 500 risk premium is 0.89 (5.46 ÷ 6.11 = 0.89). In short, the current 0.60 measured beta for electric utilities significantly underestimates the cost of equity for the utilities, providing further support for the conclusion that the CAPM underestimates the cost of equity for utilities at this time.

Q. Can you adjust for the tendency of the CAPM to underestimate the cost of equity for companies with betas significantly less than 1.0?

A. Yes. I can implement the CAPM using the 0.89 beta I discuss above, which I obtain by comparing the historical returns on utilities to historical returns on the S&P 500.

Q. What CAPM result do you obtain when you estimate the expected risk premium on the market portfolio from the arithmetic mean difference between the return on the market and the yield on 20-year Treasury bonds?

A. Using a risk-free rate equal to 3.8 percent, an electric utility beta equal to 0.60, a risk premium on the market portfolio equal to 7.1 percent, and a flotation cost allowance equal to 20 basis points, I obtain an historical CAPM estimate of the cost of equity equal to 8.2 percent for my electric utility group [3.8 + (0.60 x 7.1) + 0.20 = 8.2] (see Schedule 4). (I determine the flotation cost allowance by calculating the difference in my DCF results with and without a flotation cost allowance.)

Q. What CAPM result do you obtain when you use a beta equal to 0.89 rather than an electric utility beta equal to 0.60?

A. I obtain a CAPM result equal to 10.3 percent using a risk free rate equal to 3.8 percent, a beta equal to 0.89, the historical market risk premium equal to

7.1 percent, and a flotation cost allowance of 20 basis points (3.8 + 0.89 x 7.1+ 0.20= 10.3). (*See* Schedule 4.)

Q. What is the average of your two historical CAPM results?

A. The average of my two historical CAPM results is 9.3 percent ((8.2 percent + 10.3 percent) ÷ 2 = 9.3 percent). I conservatively use 9.3 percent as my estimate of the historical CAPM cost of equity, even though there is strong evidence justifying the use of the 10.3 percent CAPM model result, which is based on the adjusted utility beta.

2. DCF-Based CAPM

Q. How does your DCF-Based CAPM differ from your historical CAPM?

A. As noted above, my DCF-based CAPM differs from my historical CAPM only in the method I use to estimate the risk premium on the market portfolio. In the historical CAPM, I use historical risk premium data to estimate the risk premium on the market portfolio. In the DCF-based CAPM, I estimate the risk premium on the market portfolio from the difference between the DCF cost of equity for the S&P 500 and the forecasted yield to maturity on 20-year Treasury bonds.

Q. What risk premium do you obtain when you estimate the risk premium by calculating the difference between the expected return on the market (the DCF estimate for the S&P 500) and the risk-free rate?

A. Using this method, I obtain a risk premium on the market portfolio equal to 10.4 percent (14.2 percent DCF for the S&P 500) – 3.8 percent (risk-free rate) = 10.4) (see Schedule 5).

Q. What CAPM result do you obtain when you estimate the expected return on the market portfolio by applying the DCF model to the S&P 500?

A. Using a risk-free rate of 3.8 percent, an electric utility beta of 0.60, a risk premium on the market portfolio of 10.4 percent, and a flotation cost allowance of 20 basis points, I obtain a CAPM result of 10.2 percent for my electric utility group. Using a risk-free rate of 3.8 percent, an electric utility beta of 0.89, a risk premium on the market portfolio of 10.4 percent, and a flotation cost allowance of 20 basis points, I obtain a CAPM result of 13.3 percent for my electric utility group. The average of my two DCF-based CAPM results is 11.7 percent ((10.2 percent + 13.3 percent) ÷ 2 = 11.7 percent). I use 11.7 percent as my estimate of the DCF-based CAPM cost of equity.

C. COMPARABLE EARNINGS METHOD

Q. What is the comparable earnings method for estimating the required rate of return on equity?

A. The comparable earnings method estimates the required rate of return on equity by calculating the expected rate of return on book equity for a group of comparable risk companies. The United States Supreme Court states in the *Hope Natural Gas* case that the "return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks." [*Federal Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 591, 603 (1944).] The comparable earnings approach implements the *Hope* standard by calculating the expected rate of return on book equity for a group of comparable-risk companies.

Q. What comparable risk companies do you use to estimate RECO's required rate of return on equity using the comparable earnings method?

A. I use all the investment-grade Value Line electric utilities with sufficient data to estimate RECO's cost of equity using the comparable earnings method.

Q. How do you calculate the expected rate of return on book equity for these comparable-risk electric utilities?

A. I compute the expected rate of return on book equity for these comparable-risk utilities by calculating the average expected rate of return on book equity reported by The Value Line Investment Survey for the years 2018, 2019, and 2022 – 2024.

Q. Do you make any adjustments to Value Line's reported expected rates of return on book equity?

A. Yes. Value Line calculates its expected rates of return on book equity by dividing each company's expected earnings by its estimate of the company's year-end equity. Because a rate of return based on year-end equity understates the rate of return on the average equity investment during the year, I adjust Value Line's estimates to reflect expected rates of return on average equity for the year. My method for calculating the expected rate of return on average book equity for the comparable companies is described in the notes accompanying my exhibit.

Q. What average expected rate of return on book equity do you obtain for your group of comparable-risk utilities?

A. The average expected rate of return on book equity for this large group of comparable-risk utilities is 10.7 percent (see Schedule 6).

V. RECOMMENDED RATE OF RETURN ON EQUITY

Q. Based on the results of your DCF, CAPM, and comparable earnings analyses, what is your recommended allowed rate of return on equity for RECO?

A. Based on the results of my DCF, CAPM, and comparable earnings analyses, I recommend that RECO be allowed to earn a rate of return on equity equal to 10.4 percent.

Q. How do you arrive at your recommended 10.4 percent allowed rate of return on equity for RECO?

A. I arrive at my recommended 10.4 percent allowed rate of return on equity for RECO by giving a one-third weight to the results of my DCF analysis, a one-third weight to the average result of my CAPM analyses, and a one-third weight to the result of my comparable earnings analysis (see TABLE 1 below).

TABLE 1
COST OF EQUITY MODEL RESULTS

METHOD	MODEL RESULT	WEIGHT	WEIGHTED RESULT
DCF	10.1%	33%	3.37%
CAPM – Historical	9.3%		
CAPM – DCF-based	11.7%		
Average CAPM	10.5%	33%	3.50%
Comparable Earnings	10.7%	33%	3.57%
Average	10.4%		

VI. TESTS OF REASONABLENESS

Q. Do you conduct any tests of the reasonableness of your recommended 10.4 percent allowed return on equity for RECO?

A. Yes. To test the reasonableness of my recommended 10.4 percent allowed return on equity for RECO, I also examine the expected rate of return on book equity for a group of low-risk industrial companies and estimate RECO's cost of equity using two versions of the risk premium approach.

A. EXPECTED RATE OF RETURN ON BOOK EQUITY FOR GROUP OF LOW-RISK INDUSTRIAL COMPANIES

Q. Why do you test the reasonableness of your cost of equity recommendation by calculating the average Value Line expected return on book equity for a group of low-risk industrial companies?

A. I test the reasonableness of my cost of equity recommendation by calculating the average Value Line expected return on book equity for a group of low-risk industrial companies because, as I discuss above, the United States Supreme Court found in the *Hope* case that "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks." [*Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944)*.]

Q. How do you select the group of low-risk industrial companies you use to test the reasonableness of your 10.4 percent cost of equity estimate in this proceeding?

A. Beginning with the Value Line universe of more than 5,000 publicly-traded companies, I select all industrial companies in the Value Line universe of companies that pay dividends, have a Safety Rank of 1, a beta in the range .50 to .70, and Financial Strength equal to or greater than A. The average ratings for the identified group of low-risk industrials are Safety Rank, 1; beta, .68; and

Financial Strength, A+. I note that only eight companies meet this low-risk selection criteria.

Q. What is the average expected rate of return on book equity for your group of low-risk industrial companies?

A. The average expected rate of return on book equity for the identified group of low-risk industrial companies is 17.5 percent, excluding two high-end outlier results (see Schedule 7).

B. RISK PREMIUM ANALYSIS

Q. Please describe the risk premium method of estimating the cost of equity.

A. The risk premium method is based on the principle that investors expect to earn a return on an equity investment that reflects a "premium" over the interest rate they expect to earn on an investment in bonds. This equity risk premium compensates equity investors for the additional risk they bear in making equity investments versus bond investments.

Q. Does the risk premium approach specify what debt instrument should be used to estimate the interest rate component in the methodology?

A. No. The risk premium approach can be implemented using virtually any debt instrument. However, the risk premium approach does require that the debt instrument used to estimate the risk premium be the same as the debt instrument used to calculate the interest rate component of the risk premium approach. For example, if the risk premium on equity is calculated by comparing the returns on stocks to the interest rate on A-rated utility bonds, then the interest rate on A-rated utility bonds must be used to estimate the interest rate component of the risk premium approach.

Q. Does the risk premium approach require that the same companies be used to estimate the stock return as are used to estimate the bond return?

A. No. For example, many analysts apply the risk premium approach by comparing the return on a portfolio of stocks to the income return on Treasury securities such as long-term Treasury bonds. In this widely accepted application of the risk premium approach, the same companies are not used to estimate the stock return as are used to estimate the bond return, because the United States government is not a company.

Q. How do you measure the required risk premium on an equity investment in your group of publicly-traded electric utilities?

A. I use two methods to estimate the required risk premium on an equity investment in electric utilities. The first is called the *ex ante* risk premium method and the second is called the *ex post* risk premium method.

1. *Ex Ante* Risk Premium Method

Q. Please describe your *ex ante* risk premium approach for measuring the required risk premium on an equity investment in electric utilities.

A. My *ex ante* risk premium method is based on studies of the DCF expected return on a group of electric utilities compared to the interest rate on Moody's A-rated utility bonds. Specifically, for each month in my study period, I calculate the risk premium using the equation,

$$RP_{PROXY} = DCF_{PROXY} - I_A$$

where:

RP_{PROXY} = the required risk premium on an equity investment in the proxy group of companies,

DCF_{PROXY} = average DCF estimated cost of equity on a portfolio of proxy companies; and

I_A = the yield to maturity on an investment in A-rated utility bonds.

I then perform a regression analysis to determine if there is a relationship between the calculated risk premium and the yield to maturity on utility bonds. Finally, I use the results of the regression analysis to estimate the investors' required risk premium. To estimate the cost of equity, I then add the required risk premium to the forecasted yield to maturity on A-rated utility bonds. As noted above, one could use the yield to maturity on other debt investments to measure the interest rate component of the risk premium approach as long as one uses the yield on the same debt investment to measure the expected risk premium component of the risk premium approach. I choose to use the yield on A-rated utility bonds because it is a frequently-used benchmark for utility bond yields. A detailed description of my *ex ante* risk premium studies is contained in Appendix 4, and the underlying DCF results and interest rates are displayed in Schedule 8.

Q. What cost of equity do you obtain from your *ex ante* risk premium method?

A. As discussed above, to estimate the cost of equity using the *ex ante* risk premium method, one may add the estimated risk premium over the yield on A-rated utility bonds to the expected yield to maturity on A-rated utility bonds. I obtain the expected yield to maturity on A-rated utility bonds, 5.4 percent, by averaging forecast data from Value Line and the EIA. For my electric utility sample, my analyses produce an estimated risk premium over the yield on A-rated utility bonds equal to 5.1 percent. Adding an estimated risk premium of 5.1 percent to the expected 5.4 percent yield to maturity on A-rated utility bonds produces a cost of equity estimate of 10.5 percent using the *ex ante* risk premium method.

Q. How do you obtain the expected yield on A-rated utility bonds?

A. As noted above, I obtain the expected yield to maturity on A-rated utility bonds, 5.4 percent, by averaging forecast data from Value Line and the EIA. Value Line Selection & Opinion (November 30, 2018) projects a AAA-rated Corporate bond yield equal to 4.5 percent. The average spread between A-rated utility bonds and Aaa-rated Corporate bonds is 42 basis points (A-rated utility, 4.35 percent, less Aaa-rated Corporate, 3.93 percent, equals 42 basis points). Adding 42 basis points to the 4.5 percent Value Line Aaa Corporate bond forecast equals a forecast yield of 4.92 percent for the A-rated utility bonds. The EIA forecasts an AA-rated utility bond yield equal to 5.71 percent. The spread between AA-rated utility and A-rated utility bonds is 17 basis points (4.35 percent less 4.18 percent). Adding 17 basis points to EIA's 5.71 percent AA-utility bond yield forecast equals a forecast yield for A-rated utility bonds equal to 5.88 percent. The average of the forecasts (4.92 percent using Value Line data and 5.88 percent using EIA data) is 5.4 percent.

Q. Why do you use an expected or forecasted yield to maturity on A-rated utility bonds rather than a current yield to maturity?

A. I use an expected or forecasted yield to maturity on A-rated utility bonds rather than a current yield to maturity because the fair rate of return standard requires that a company have an opportunity to earn its required return on its investment during the forward-looking period during which rates will be in effect. Economists project that future interest rates will be higher than current interest rates as the Federal Reserve allows interest rates to rise in order to prevent inflation. Thus, the use of forecasted interest rates is consistent with the fair rate of return standard, whereas the use of current interest rates at this time is not.

2. *Ex Post* Risk Premium Method

Q. Please describe your *ex post* risk premium method for measuring the required risk premium on an equity investment in electric utilities.

A. I first perform a study of the comparable returns received by bond and stock investors over the 82 years of my study. I estimate the returns on stock and bond portfolios, using stock price and dividend yield data on the S&P 500 and bond yield data on Moody's A-rated Utility Bonds. My study consists of making an investment of one dollar in the S&P 500 and Moody's A-rated utility bonds at the beginning of 1937, and reinvesting the principal plus return each year to 2019. The return associated with each stock portfolio is the sum of the annual dividend yield and capital gain (or loss) which accrued to this portfolio during the year(s) in which it was held. The return associated with the bond portfolio, on the other hand, is the sum of the annual coupon yield and capital gain (or loss) which accrued to the bond portfolio during the year(s) in which it was held. The resulting annual returns on the stock and bond portfolios purchased in each year between 1937 and 2019 are shown on Schedule 9. The average annual return on an investment in the S&P 500 stock portfolio is 11.21 percent, while the average annual return on an investment in the Moody's A-rated utility bond portfolio is

6.56 percent. The risk premium on the S&P 500 stock portfolio is, therefore, 4.65 percent.

I also conduct a second study using stock data on the S&P Utilities rather than the S&P 500. As shown on Schedule 10, the average annual return on the S&P Utility stock portfolio is 10.6 percent per year. Thus, the return on the S&P Utility stock portfolio exceeds the return on the Moody's A-rated utility bond portfolio by 4.0 percent (10.6 – 6.6 = 4.0).

Q. Why is it appropriate to perform your *ex post* risk premium analysis using both the S&P 500 and the S&P Utilities stock indices?

A. I perform my *ex post* risk premium analysis on both the S&P 500 and the S&P Utilities because I believe electric energy companies today face risks that are somewhere in between the historical average risk of the S&P Utilities and the S&P 500 over the years 1937 to 2019. Thus, I use the average of the two historically-based risk premiums as my estimate of the required risk premium for the Company in my *ex post* risk premium method.

Q. Would your study provide a different risk premium if you started with a different time period?

A. Yes. The risk premium results vary somewhat depending on the historical time period chosen. My policy is to use the largest set of reliable historical data. I thought it would be most meaningful to begin after the passage and implementation of the Public Utility Holding Company Act of 1935. This Act significantly changed the structure of the public utility industry. Because the Public Utility Holding Company Act of 1935 was not implemented until the beginning of 1937, I felt that numbers taken from before this date would not be comparable to those taken after. (The repeal of the 1935 Act has not materially impacted the structure of the public utility industry; thus, the Act's repeal does not have any impact on my choice of time period.)

Q. Why is it necessary to examine the yield from debt investments in order to determine the investors' required rate of return on equity capital?

A. As previously explained, investors expect to earn a return on their equity investment that exceeds currently available bond yields because the return on equity, as a residual return, is less certain than the yield on bonds; and investors must be compensated for this uncertainty. Investors' expectations concerning the amount by which the return on equity will exceed the bond yield may be influenced by historical differences in returns to bond and stock investors. Thus, we can estimate investors' expected returns from an equity investment from information about past differences between returns on stocks and bonds. In interpreting this information, investors would also recognize that risk premiums increase when interest rates are low.

Q. What conclusions do you draw from your *ex post* risk premium analyses about the required return on an equity investment in electric utilities?

A. My studies provide evidence that investors today require an equity return of at least 4.0 to 4.6 percentage points above the expected yield on A-rated utility bonds. As discussed above, the expected yield on A-rated utility bonds is 5.4 percent. Adding a 4.0 to 4.6 percentage point risk premium to a yield of 5.4 percent on A-rated utility bonds, I obtain an expected return on equity in the range 9.4 percent to 10.1 percent, with a midpoint estimate equal to 9.7 percent. Adding a 20 basis point allowance for flotation costs, I obtain an estimate of 9.9 percent as the *ex post* risk premium cost of equity.

Q. Do the results of your ex ante and ex post risk premium analyses combined with your other analyses support the 10.4 percent cost of equity model results you show in Table 1 above?

A. Yes. The average results from applying all these cost of equity models is also equal to 10.4 percent (see TABLE 2 below).

TABLE 2
COST OF EQUITY MODEL RESULTS INCLUDING RISK PREMIUM ANALYSES

METHOD	MODEL RESULT
DCF	10.1%
CAPM – Historical	9.3%
CAPM – DCF-based	11.7%
Comparable Earnings	10.7%
Ex Ante Risk Premium	10.5%
Ex Post Risk Premium	9.9%
Average	10.4%

Q. Does this conclude your direct testimony?

A. Yes, it does.

ROCKLAND ELECTRIC COMPANY
DIRECT TESTIMONY OF
YUKARI SAEGUSA

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Yukari Saegusa and my business address is 4 Irving Place, New York, NY 10003.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am Vice President and Treasurer of Consolidated Edison Company of New York, Inc. ("Con Edison"). I am also Treasurer of Orange and Rockland Utilities, Inc. ("Orange and Rockland"), which is an affiliate of Con Edison, as well as the corporate parent of Rockland Electric Company ("RECO" or the "Company").

Q. BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I graduated from the University of Pennsylvania, Wharton School in 1989 and received Bachelor of Science degree in Economics. I received an MBA from the MIT Sloan School of Management in 1995.

Q. PLEASE SUMMARIZE YOUR PROFESSIONAL BACKGROUND.

A. I joined Con Edison in March 2013. Prior to joining Con Edison, from 2004 to 2013, I was employed by Barclays as a Managing Director in Debt Capital Markets covering the US utility and energy sectors. I was employed from 1995 to 2004 by Citigroup also in Debt Capital Markets covering the US utility sector. In my roles at Barclays and Citigroup, I was broadly responsible for advising utility clients on the design and execution of debt capital-raising and liability management strategies.

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES.

A. My responsibilities include oversight of corporate liquidity, pensions, insurance, risk management and debt and equity financings for Consolidated Edison, Inc. ("CEI"), and its subsidiaries, including Con Edison, Orange and Rockland and RECO.

Q. HAVE YOU PREVIOUSLY SPONSORED TESTIMONY BEFORE THE NEW JERSEY BOARD OF PUBLIC UTILITIES ("NJBPU")?

A. Yes, I provided testimony on behalf of RECO in its last two base rate proceeding, *i.e.*, BPU Docket Nos. ER13111135 and ER16050428.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. My testimony supports the capital structure and overall weighted average cost of capital ("WACC"), also known as the overall rate of return, used to determine RECO's revenue requirements. I rely on the testimony of Company witness Vander Weide for RECO's current cost of equity capital.

CAPITALIZATION AND COST OF CAPITAL

Q. WHAT CAPITAL STRUCTURE SHOULD BE USED IN THE CALCULATION OF THE OVERALL WACC FOR RECO IN THIS PROCEEDING?

A. I recommend the use of the consolidated capitalization of Orange and Rockland in this proceeding.

Q PLEASE DESCRIBE THE CONSOLIDATED CAPITALIZATION OF ORANGE AND ROCKLAND.

A. Consolidated capitalization refers to the consolidated capital structure of Orange and Rockland and its wholly-owned utility subsidiary, RECO. The consolidated capital structure is presented in Exhibit P-4 and consists of the following Schedules:

Schedule 1 – Consolidated Capitalization and Cost Rates at March 31, 2019;

Schedule 2 – Consolidated Capitalization and Cost Rates at September 30, 2019 (Forecast);

Schedule 3 – Long-Term Debt Detail at March 31, 2019; and

Schedule 4 – Long-Term Debt Detail at September 30, 2019 (Forecast).

Q. WHAT IS THE SIGNIFICANCE OF THE MARCH 31, 2019 AND THE SEPTEMBER 30, 2019 DATES USED IN YOUR EXHIBITS?

A. In this case, RECO has used a test year that is the twelve-month period ending September 30, 2019 ("Test Year"). The end date for the Test Year is, therefore, the appropriate date of the projected capitalization, subject to known and measurable changes. The last month of historic data available for this filing is March 31, 2019 and is, therefore, the starting point for projecting RECO's capital structure.

Q. PLEASE DESCRIBE ANY PROJECTED CHANGES IN LONG-TERM DEBT AND HOW SUCH CHANGES HAVE BEEN INCORPORATED INTO YOUR FORECASTED DATA AT SEPTEMBER 30, 2019.

A. The forecasted balance of long-term debt at September 30, 2019 includes the contemplated issuance, by Orange and Rockland, of Series A 2019 debentures, $125 million, 5.20%, due September 1, 2049. The financing is contemplated to occur before the conclusion of the Test Year. The other projected change in the long-term debt balance between the historic data date (*i.e.*, March 31, 2019) and the end of the Test Year is the result of the periodic amortization of the balance of the Unamortized Debt Discount, Unamortized Debt Expenses and Unamortized Loss on Reacquired Debt.

Q. PLEASE DESCRIBE HOW YOU DEVELOPED THE COST OF LONG-TERM DEBT AND EXPLAIN THE CHANGE IN THE COST OF LONG-TERM DEBT BETWEEN THE ACTUAL HISTORIC DATA AND THE PROJECTED COST AT SEPTEMBER 30, 2019.

A. Exhibit P-4, Schedules 3 and 4, present the detailed calculation of the cost of the long-term debt at March 31, 2019 and September 30, 2019, respectively. The schedules detail each issue of long-term debt outstanding and calculate an effective annual cost for each issue, taking into consideration the original net proceeds to the Company and annual interest costs. The sum of the effective annual cost for all issues is divided by the gross amount of debt outstanding to derive the weighted average cost of long-term debt.

Q. PLEASE DESCRIBE THE DERIVATION OF THE EQUITY BALANCE AT MARCH 31, 2019 AND THE METHOD USED TO PROJECT THE EQUITY BALANCE THROUGH SEPTEMBER 30, 2019.

A. The actual equity balance at March 31, 2019, as shown on Exhibit P-4, Schedule 1, is the consolidated equity of Orange and Rockland and RECO. The equity of all non-utility subsidiaries has been eliminated, and the retained earnings balance excludes the effect of Other Comprehensive Income. The forecasted equity balance at September 30, 2019, as shown on Exhibit P-4, Schedule 2, contemplates a $35 million increase in the common stock component of common stock equity, as a result of an equity investment by CEI into Orange and Rockland and RECO. The forecasted retained earnings balance at September 30, 2019 was calculated by assuming an earned return on common equity of 10.0% and quarterly dividends of $11.75 million in March, June and September 2019.

Q. WHAT IS THE BASIS FOR YOUR USE OF A 10.0% RETURN ON EQUITY IN DEVELOPING THE FORECASTED BALANCE OF COMMON EQUITY AT SEPTEMBER 30, 2019?

A. Company witness Vander Weide presents direct testimony in this case addressing RECO’s cost of equity capital. The 10.0% return on equity is based on the required equity return recommended by Company witness Vander Weide of 10.4%. The Company is proposing a return on equity lower than Company witness Vander Weide’s recommendation in order to minimize the contested issues in this proceeding and to facilitate a settlement. The 10.0% return on equity was used as a means of estimating retained earnings for Orange and Rockland's consolidated results through the end of the Test Year in this case.

Q. WHAT CAPITAL STRUCTURE RESULTS FROM THE CALCULATIONS THAT YOU DESCRIBED?

A. Exhibit P-4, Schedule 1, shows the actual consolidated capital structure at March 31, 2019 of 48.64% long-term debt and 51.36% common stock equity. The projected consolidated capital structure at September 30, 2019, as shown on Exhibit P-4, Schedule 2, is 50.07% long-term debt and 49.93% common stock equity.

Q. WHY IS IT REASONABLE AND APPROPRIATE TO USE THE CONSOLIDATED CAPITAL STRUCTURE AND EQUITY RATIO OF ORANGE AND ROCKLAND TO DETERMINE THE WACC FOR RECO?

A. The use of Orange and Rockland's consolidated capital structure and equity ratio is reasonable and appropriate given the joint operations and financing by Orange and Rockland and its utility subsidiary, RECO. As such, use of a consolidated capital structure is reasonable and appropriate because it represents the actual ratios for investment of capital required to provide services to customers.

Q. IS THERE OTHER EVIDENCE SUPPORTING THE REASONABLENESS OF THE PROPOSED COMMON STOCK EQUITY RATIO IN THIS PROCEEDING?

A. Yes, the reasonableness of the use of the consolidated Orange and Rockland capital structure and equity ratio is confirmed based on a proxy group comparative analysis. The analysis (Exhibit YS-1) compares the equity ratio of comparable utility operating companies and the results demonstrate that the Company's proposed equity ratio is in line with the mean year-end 2018 equity ratio of the proxy group companies of 53.3%.

Q. MS. SAEGUSA, USING YOUR RECOMMENDED CAPITAL STRUCTURE AND COST OF LONG-TERM DEBT AND THE COMPANY'S PROPOSED COST OF EQUITY AS SUPPORTED BY COMPANY WITNESS VANDER WEIDE, WHAT OVERALL RATE OF RETURN IS REQUESTED IN THIS FILING?

A. The overall rate of return, or WACC, is 7.56% as shown on Exhibit P-4, Schedule 2.

Q. WHAT ARE THE COMPANY'S CREDIT RATINGS BY THE MAJOR RATINGS AGENCIES?

RECO has a long-term issuer rating of A- from Standard & Poor's ("S&P") and an issuer default rating of BBB+ from Fitch Ratings ("Fitch"). RECO has a Stable Outlook from S&P and Fitch. Moody's does not rate the credit of RECO. In the overall Orange and Rockland complex, RECO represents approximately 15% of Orange and Rockland's total operating income. Therefore, Orange and Rockland's credit ratings partially reflect the credit quality of RECO. Moody's long-term debt rating (senior unsecured) for Orange and Rockland is Baa1 with a Stable Outlook. S&P's long-term debt rating (senior unsecured) for Orange and Rockland is A- with a Stable Outlook. Fitch's long-term debt rating (senior unsecured) for Orange and Rockland is A- with a Stable Outlook.

Q. PLEASE EXPLAIN WHY IT IS IMPORTANT FOR ORANGE AND ROCKLAND AND RECO TO MAINTAIN THEIR CURRENT CREDIT RATINGS?

A. RECO plans to invest a significant amount of capital in its infrastructure to maintain system reliability. Strong credit ratings will enable Orange and Rockland, on behalf of RECO, to access the capital markets in all types of market conditions and achieve favorable pricing and terms from investors. The maintenance of strong credit ratings depends in large part on the determinations of state regulators to recognize appropriate equity ratios and returns on equity.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

Rockland Electric Company
Docket No. ___________________

Exhibits

Volume I

ROCKLAND ELECTRIC COMPANY

EXHIBITS

VOLUME I

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

I/M/O 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

VERIFIED PETITION

May 3, 2019

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

I/M/O 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	))))))	VERIFIED PETITION

Rockland Electric Company ("RECO," the "Company," or "Petitioner") a corporation of the State of New Jersey, which is subject to the jurisdiction of the Board of Public Utilities ("Board") and which has its principal offices at One Lethbridge Plaza, Suite 32 – Second Floor, Route 17 North, Mahwah, New Jersey 07430, respectfully petitions the Board as follows:

1. Petitioner is engaged in the retail distribution of electric energy and the provision of electric Basic Generation Service for residential, commercial and industrial purposes within the State of New Jersey. The Board has jurisdiction over Petitioner's electric distribution rates pursuant to and accordance with N.J.S.A 48:2-2-1 et. seq. Petitioner provides electric distribution service to approximately 73,000 customers in an area which extends from eastern Bergen County at the Hudson River to western Passaic County and small communities in Sussex County, New Jersey.

2. The rates and charges for electric service furnished by Petitioner and the conditions upon which the same are furnished are set forth in Petitioner's tariff designated B.P.U. No. 3 - Electricity.

3. Petitioner's current electric distribution rates are not just and reasonable because they do not produce an adequate, reasonable return on the Company's invested

capital that is dedicated to the service of the Company's electric distribution customers and do not provide sufficient revenues to recover the Company's investment in rate base, operating expenses, financing costs and taxes. In Petitioner's last electric base rate case (*i.e.*, Docket No. ER16050428), as decided by the Board's Order Approving Stipulation dated February 22, 2017 ("2017 RECO Base Rate Order"), the Board increased Petitioner's electric base distribution rates by $1.7 million, or 0.7 percent. Since the Board's adjustment of rates over two years ago in the 2017 RECO Base Rate Order, Petitioner has continued to invest in its electric distribution system so as to provide for safe, adequate and proper electric service to the Company's electric customers, and Petitioner requires additional revenues to recover the costs of such investments. Among other investments, the Company has implemented the Advanced Metering Infrastructure ("AMI") Program approved by the Board in its Decision and Order, dated August 23, 2017, in BPU Docket No. ER16060524 ("AMI Order"). Petitioner's current rates do not provide for any recovery of or a return on these AMI investments. Petitioner is also seeking recovery for significant incurred and deferred costs relating to winter storms Riley and Quinn that struck RECO's service territory in March 2018. Petitioner faces increased taxes, rising interest rates that have increased its financing costs, inflationary pressures that have increased the cost of labor and materials, additional vegetation management (*i.e.*, tree trimming) expenses, and decreasing sales revenues as a result of customers implementing energy efficiency and conservation strategies to lower their average electric energy consumption. While the Company has experienced the above-described rising costs and lower sales since its last base rate case, during the same period

Petitioner has implemented a series of base rate decreases, as described in paragraph 5 below.

4. Petitioner proposes changes to its electric distribution rates and charges pursuant to N.J.S.A. 48:2-21 to be effective on June 2, 2019. If the Board follows its typical process in a litigated rate proceeding of issuing two four-month suspensions of the proposed adjustment, rates could become effective February 2, 2020. The proposed increased rates and charges are designed to produce additional revenues of $19.9 million,which amounts to a 9.6% increase on a total revenue including an estimate of supply costs for retail access customers. The proposed increase is based on the twelve-month period ending September 30, 2019, as adjusted for known and measurable changes, and is subject to increase or decrease upon the Company's filing of updated information. This additional revenue is necessary to allow Petitioner to pay the costs incurred in providing safe and reliable electric service to its customers, and to enable Petitioner to earn a reasonable rate of return on the value of its facilities used and useful in supplying such service. The proposed rates should be approved to enable RECO to maintain its creditworthiness at a level sufficient to raise capital necessary to properly perform its obligations to provide safe, adequate and proper service to its present and future electric customers.

5. The Board should evaluate the Company's proposal to increase the Company's electric distribution rates, as set forth in this Petition, in light of the various changes to the Company's electric distribution rates since the 2017 RECO Base Rate Order (discussed in the direct testimony of the Accounting Panel), particularly those resulting from the Federal Tax Cuts and Jobs Act of 2017 ("2017 Tax Act"), that

collectively resulted in a significant overall reduction in rates. In its Decision and Order dated June 22, 2018 in BPU Docket No. ER18030236, the Board authorized a total rate refund relating to the Stub Period (*i.e.*, January 1 through March 31, 2018) over-collection of approximately $1.019 million during July 2018. The Board also made final the interim reduction in the Company's annual revenue requirement of $2.868 million. The Board authorized the refund to customers of the unprotected accumulated deferred income taxes of approximately $10.6 million (gross up amount), inclusive of SUT, over a three-year period, commencing in July 2018. Excluding the one-time refund of $1.019 million during July 2018, the annual reduction to base rates through June 2020 relating to the TCJA will be $6.4 million (*i.e.*, $2.868 million plus $3.553 million [$10.6 million/3 years]). In addition, effective August 1, 2018, the Company reduced base rates by $6.413 million in order to eliminate the four-year recovery of deferred extraordinary storm damage costs of approximately $25,652,364 pursuant to the Board's Order Approving Stipulation dated July 23, 2014 in I/M/O the Verified Petition of Rockland Electric Company for Approval of Changes in Electric Rates, et al., (BPU Docket No. ER13111135). Further, in June 2019, the Company will eliminate the Transition Bond Charge, which will have the effect of reducing customer bills by an additional $3.7 million annually. The result of these significant rate reductions, as well as two upward Storm Hardening Program base rate adjustments (of approximately $500,000 and $400,000, respectively), is a net rate reduction of approximately $15.6 million since RECO's 2017 RECO Base Rate Order, even excluding the Stub Period refund. Taking into account these net base rate decreases of approximately $15.6 million, which was equivalent to 9.2% of total revenues reflected in the 2017 Rate Order, the overall net increase to customers since the 2017 RECO Base Rate Order would be approximately $4.3 million ($19.9 million less $15.6 million) or 2.1%.

6. As part of this Petition, Petitioner requests approval to change its electric and general plant depreciation rates pursuant to N.J.S.A. 48:2-18. Petitioner also requests approval for an additional allowance for negative salvage costs (*i.e*., plant removal costs) that is needed based on actual expenditures incurred by the Company since 2017, as well as a true-up of the existing net salvage allowance currently in rates. The proposed depreciation rates and negative salvage allowance are proper, adequate, and sufficient consistent with industry standards, as addressed in the direct testimony of the Company's Depreciation Panel. Petitioner requests that the Board approve its proposed electric depreciation rates simultaneously with the effective date of the new electric rates resulting from this proceeding. The proposed base rates requested herein are designed to recover the depreciation expense resulting from approval of the Company's proposed electric depreciation rates as applied to its year-end plant balances (*i.e*., as of December 31, 2018).

7. Petitioner also requests that the Board find to be prudent the Company's investments under its Storm Hardening Program previously approved by the Board,[1] in various upgrades designed to protect the Company's infrastructure from future major storm events. As discussed in the direct testimony of the Accounting Panel and the Capital Budget and Plant Addition Panel, based on such finding, Petitioner requests the Board to finalize the rate recovery of Storm Hardening Progam capital investments that

[1] *I/M/O the Verified Petition of Rockland Electric Company for Establishment of a Storm Hardening Surcharge*, BPU Docket No. ER14030250, Decision and Order Approving Stipulation (dated January 28, 2016) ("RECO Storm Hardening Order").

the Board has previously authorized to be included in base rates on a provisional basis in periodic Storm Hardening Program rate adjustment filings.

8. Petitioner also requests that the Board find to be prudent the Company's implementation of its AMI Program and the AMI Program costs that have been incurred pursuant to the AMI Order. In addition, the Company seeks approval of its proposal for the recovery of the net book value of the legacy meters that had to be removed as part of the AMI Program and that the Board authorized to be deferred in the AMI Order.

9. The Company is presenting the direct testimony of eight witnesses/witness panels in support of this Petition. The Accounting Panel, consisting of John de la Bastide, Director-Financial Services, Kyle Ryan, Department Manager–Regulatory Filings, and Wenqi Wang, Department Manager of Regulatory Accounting and Revenue Requirements, will address accounting issues and present the lead-lag study results and information regarding the Company's income statement, rate base, revenue, and employee benefits. James H. Vander Weide, President of Financial Strategy Associates, will discuss the Company's cost of equity capital. Yukari Saegusa, Director, Corporate Finance, will discuss the Company's capital structure. The Capital Budget and Plant Addition Panel, consisting of Wayne Banker, Chief Engineer – Distribution Engineering, John Coffey, Chief Engineer – Transmission and Substation Engineering, and Angelo M. Regan, Director of Electrical Engineering, will present the Company's plant additions and capital budget, and discuss the Company's proposed Control Center and Substation Programs, the status of the Company's Storm Hardening Program, and a proposed modification to the Company's major storm cost reserve. The Depreciation Panel, consisting of Matthew Kahn, Section Manager, Property Tax and Depreciation, and Ned

W. Allis of Gannett Fleming Valuation and Rate Consultants, LLC, will present the Company's depreciation study and proposed depreciation rates. The Electric Rate Panel, consisting of Cheryl Ruggiero, Department Manager, Orange and Rockland Rate Design, Lucy Villeta, Section Manager in the Load Research and Cost Analysis Section of the Rate Engineering Department, and Shajan Jacob, Project Manager, Orange and Rockland Rate Design, is responsible for the electric embedded cost of service ("ECOS") study and rate design. The Income Tax Panel consisting of Jeffrey Kalata, Vice President of Tax, Matthew Kahn, Section Manager, Property Tax and Depreciation, and Michael Rufino, Department Manager, will discuss certain federal income tax issues. Keith Scerbo, Director of Advanced Metering Infrastructure, will address the Company's implementation of its AMI Program.

10. Petitioner files with this Petition proposed revised draft tariff leaves, which will increase Petitioner's rates and charges for sales of electricity to residential customers (Service Classification Nos. 1 and 3 and 5), general service customers (Service Classification Nos. 2 and 7), street lighting customers (Service Classification No. 4) and private area lighting customers (Service Classification No. 6).

11. The proposed revised tariff leaves are attached as Exhibit "A," and a red-lined/strikeout version of the revised tariff leaves containing text changes is attached as Exhibit "B." Exhibit "C" is the Company's present and proposed rates in brief. Exhibit "D" is a statement of revenue derived in 2018 from the customers whose rates will be affected by the proposed increase.

12. The Company has proposed a rate design based on a proper, Company-sponsored ECOS study. The Company has also complied with the 2017 RECO Base

Rate Order (p. 7), which requires the Company to provide the parties an ECOS study using an Average and Peak ("A&P") method without endorsing that methodology or supporting the A&P ECOS study or any rate design based thereon. As discussed by the Company's Electric Rate Panel, the A&P method does not reflect the way in which the Company actually designs and constructs its distribution facilities. The A&P method has not been adopted in prior Board proceedings to set the Company's base rates. It would be inappropriate to use the A&P method to set RECO's rates in this proceeding. Consequently, RECO has not used the A&P method to develop its proposed rates, and it should not be adopted in this case. Preparation of an alternative, unsupported ECOS study is an inefficient use of Company resources and should not be required in RECO's next base rate case.

13. Pursuant to N.J.A.C. 14:1-5.12(d), Petitioner will combine the notices of this Petition and of the public hearings and will give them in accordance with the Board's regulations governing notice of the public hearings.

14. In addition to filing this Petition with the Board, copies of this Petition will be duly served by hand delivery upon the Director, Division of Rate Counsel, 140 East Front Street, 4th Floor, Trenton, New Jersey 08625 and by mail upon the Department of Law and Public Safety, Division of Law, 124 Halsey Street, 5th Floor, P.O. Box 45029, Newark, New Jersey 07101. The Company will provide copies of this Petition to municipalities and counties pursuant to the requirements of N.J.A.C. 14:1-5.12(b). A copy of this Petition also will be posted on the Company's website.

15. Information required by the Rules and Practice of the Board, N.J.A.C. 14:1-5.12 is attached hereto, made part hereof and designated as follows:

Table of Schedules

P-1 Historical Financial Statements

P-2 Electric Cost of Service

P-3 Electric Rate Base

P-4 Capitalization and Cost of Capital

P-5 Rate Designs (one based on the Company-sponsored ECOS study; the other based on the unsupported ECOS study reflecting the A&P method)

P-6 AMI Quarterly Metric Report

P-7 Depreciation Study

P-8 ECOS Studies (one based on the Company-sponsored methodology; the other based on the unendorsed A&P methodology)

16. Communications and correspondence related to this Petition should be sent as follows:

James C. Meyer, Esq.
Riker, Danzig, Scherer, Hyland & Perretti LLP
Headquarters Plaza
One Speedwell Avenue
P.O. Box 1981
Morristown, NJ 07962-1981
jmeyer@riker.com

and

John L. Carley, Esq.
Associate General Counsel
Consolidated Edison Company of New York, Inc.
Law Department, Room 1815S
4 Irving Place
New York, NY 10003
carleyj@coned.com

and

John de la Bastide
Director-Financial Services
Orange and Rockland Utilities, Inc.
One Blue Hill Plaza
Pearl River, NY 10965

WHEREFORE, Petitioner respectfully requests that the Board consider this matter and issue a decision and order pursuant to N.J.S.A. 48:2-21, N.J.S.A. 48:2-18, and/or any other applicable statutes or regulations:

1. Finding that the Company's current rates and charges for electric service are not adequate to recover the operating, capital and other costs of the Company, do not provide an adequate return on investment, and are not just and reasonable;

2. Approving the proposed rates and charges for electric service set forth in this Petition and supporting testimony and tariffs as just and reasonable, to become effective for service rendered on and after June 2, 2019 (but in no event later than the anticipated conclusion of the Board-ordered suspension period(s) on February 2, 2020);

3. Approving the proposed revised tariff leaves for inclusion in RECO's Tariff B.P.U. No. 3 – Electricity on and after the effective date of the new rates addressed above;

4. Approving the proposed depreciation rates for electric and general plant and the resulting change in electric distribution rates as just and reasonable;

5. Finding that it would be inappropriate to rely on an ECOS study or rate design using the A&P method in this proceeding, and that the Company need not file such an alternative ECOS study in its next base rate submission;

6. Finding to be prudent the Company's investments under the Board-approved Storm Hardening Program in various storm hardening related upgrades designed to protect the Company's infrastructure from future major storm events, and finalizing the rate recovery of Storm Hardening Program investments previously included in base rates on a provisional basis;

7. Finding to be prudent the Company's implementation of the AMI Program and the AMI Program costs and approving the Company's proposal for recovery of legacy meter costs; and

8. Providing such other relief as is just and proper.

Respectfully submitted,

ROCKLAND ELECTRIC COMPANY

By ______________________

James C. Meyer, Esq.
Riker, Danzig, Scherer, Hyland &
Perretti LLP
Headquarters Plaza
One Speedwell Avenue
P.O. Box 1981
Morristown, NJ 07962-1981

And

John L. Carley, Esq.
Assistant General Counsel
Consolidated Edison Company Of
New York, Inc.
Law Department, Room 1815-S
4 Irving Place
New York, NY 10003

Attorneys for Rockland Electric
Company

Dated: May 3, 2019

STATE OF NEW YORK)
: ss
COUNTY OF ROCKLAND)

JOHN DE LA BASTIDE, of full age, being duly sworn according to law, on his oath deposes and says

1. I am the Treasurer of Rockland Electric Company, the Petitioner in the foregoing Petition.

2. I have read the annexed petition, and the matters and things contained therein are true to the best of my knowledge and belief.

John de la Bastide

Sworn to and subscribed to
Before me this 3rd day
Of May, 2019

Daniel J. Perretti
DANIEL J. PERRETTI
Notary Public, State of New York
No. 4988442
Qualified in Rockland County
Commission Expires Nov. 04, 2021

DRAFT

TABLE OF CONTENTS (Continued)

(Continued)

GENERAL INFORMATION

No. 17 EXTENSION OF LINES AND FACILITIES (Continued)
APPENDIX A

EXHIBIT I
UNIT COSTS OF UNDERGROUND CONSTRUCTION
SINGLE PHASE

	ITEM	UNIT	TOTAL COST
(1)	Trenching	PER FOOT	$11.70*
	Pavement Cutting and Restoration	PER FOOT	28.98
	Blasting and Rock Removal	PER FOOT	ACTUAL LOW BID
	Jack Hammering and Rock Removal	PER FOOT	ACTUAL LOW BID
(2)	Primary Cable (#2 Aluminum)	PER FOOT	5.26
(3)	Secondary Cable		
	(a) 4/0 AAC Triplex	PER FOOT	3.93
	(b) 350 kcmil Aluminum	PER FOOT	4.89
(4)	Service (Installed in conduit, includes tap on, does not include trenching) Up to 200 AMP	PER FOOT	16.39
	Service (Installed in conduit, includes tap on, does not include trenching) Over 200 AMP	PER FOOT	18.34

* Will be adjusted to reflect any contribution received from cable television companies.

(Continued)

DRAFT

Revised Leaf No. 32
Superseding Revised Leaf No. 32

GENERAL INFORMATION

No. 17 EXTENSION OF LINES AND FACILITIES (Continued)
APPENDIX A

EXHIBIT I
UNIT COSTS OF UNDERGROUND CONSTRUCTION
SINGLE PHASE (Continued)

	ITEM	UNIT	TOTAL COST
(5)	Primary Termination /Riser	EACH	$2,109.00
	Secondary Termination/Riser	EACH	1,105.00
(6)	Primary Junction Enclosure		
	(a) Single Phase Boxpad - Unfused	EACH	1,899.00
	(b) Single Phase Switch - Fused	EACH	8,681.00
(7)	Secondary Enclosure		
	(Incl. Terminations)	EACH	481.00
(8)	Conduit (2" Schedule 40 PVC, installed)	PER FOOT	3.16
	Conduit (4" Schedule 40 PVC, installed)	PER FOOT	4.84
(9)	Street Light Cable		
	#2 Triplex in Conduit	PER FOOT	6.54
(10)	Transformers, Including Pad		
	25 KVA	EACH	5,181,00
	50 KVA	EACH	5,508.00
	75 KVA	EACH	5,880.00
	100 KVA	EACH	6,496.00
	167 KVA	EACH	7,979.00
(11)	Street Lighting - U/G Feed		
	30' Pole (including arm & luminaire)	EACH	2,127.69

(Continued)

GENERAL INFORMATION

No. 17 EXTENSION OF LINES AND FACILITIES (Continued)
APPENDIX A

EXHIBIT II
UNIT COSTS OF UNDERGROUND CONSTRUCTION
THREE PHASE

	ITEM	UNIT	TOTAL COST
(1)	Primary Cable Installation		
	(a) 750 kcmil – 600A	PER CIRCUIT FOOT	$100.11
	(b) 350 kcmil – 400A	PER CIRCUIT FOOT	57.54
	(c) 2/0 Cu – 200A	PER CIRCUIT FOOT	31.37
(2)	Secondary Cable Installation		
	350 kmcil 4-Wire	PER CIRCUIT FOOT	11.87
(3)	Service		
	350 kmcil AAC	PER CIRCUIT FOOT	21.94
(4)	Primary Termination /Riser		
	(a) 750 kcmil – 600A	EACH	1,123.00
	(b) 350 kcmil – 400A	EACH	909.00
	(c) 2/0 Cu – 200A	EACH	348.00
	(d) #2 Al – 100A	EACH	340.00
(5)	Primary Junction Box		
	(a) 200 A Installation Only	EACH	3,157.00
	(b) 2/0 AWG Termination	EACH	273.00
	(c) # 2 AWG Termination	EACH	277.00
(6)	Primary Switch - PMH FOR 400A OR 600A		
	(a) Switch Installation	EACH	24,287.00
	(b) 750 kcmil Termination	EACH	885.00
	(c) 350 kcmil Termination	EACH	636.00
	(d) 2/0 AWG Termination	EACH	348.00
	(e) #2 AWG Termination	EACH	340.00

(Continued)

DRAFT

GENERAL INFORMATION

No. 17 EXTENSION OF LINES AND FACILITIES (Continued)
APPENDIX A

EXHIBIT II
UNIT COSTS OF UNDERGROUND CONSTRUCTION
THREE PHASE (Continued)

	ITEM	UNIT	TOTAL COST
(7)	Primary Switch - Elliot for 200A		
	(a) Switch Installation	EACH	$16,900.00
	(b) 2/0 AWG Termination	EACH	273.00
	(c) #2 AWG Termination	EACH	277.00
(8)	Conduit		
	(4” Schedule 40 PVC, installed)	PER FOOT	4.84
	(6" Schedule 40 PVC, installed)	PER FOOT	6.75
(9)	Transformers, Including Pad		
	150 KVA	EACH	14,137.00
	300 KVA	EACH	16,911.63
(10)	Concrete Pullbox		
	Materials	EACH	10,113.00
	Labor	EACH	ACTUAL LOW BID
(11)	Concrete Manhole		
	Materials	EACH	19,733.00
	Labor	EACH	ACTUAL LOW BID
(12)	Trenching - Mainline Construction	PER FOOT	ACTUAL LOW BID

(Continued)

GENERAL INFORMATION

No. 17 EXTENSION OF LINES AND FACILITIES (Continued)
APPENDIX A

EXHIBIT III
UNIT COSTS OF OVERHEAD CONSTRUCTION
SINGLE PHASE AND THREE PHASE

	ITEM	UNIT	TOTAL COST
(1)	Pole Line (Includes 45 ft. Poles Anchors & Guys)	PER FOOT	$15.03*
(2)	Primary Wire		
	(a) Single Phase (3/0 ACSR)	PER FOOT	5.31
	(b) Three Phase (477 kmcil Aluminum)	PER FOOT	15.17
	(c) Three Phase (3/0 ACSR)	PER FOOT	13.13
	(d) Neutral	PER FOOT	3.34
(3)	Secondary Wire		
	(a) 3-Wire (2/0 TX)	PER FOOT	6.26
	(b) 4-Wire (2/0 QX)	PER FOOT	6.85
(4)	Service - Single Phase		
	Up To 200 AMP	PER FOOT	3.73
	Over 200 AMP	PER FOOT	4.54
(5)	Service - Three Phase		
	Up To 200 AMP	PER FOOT	4.60
	Over 200 AMP	PER FOOT	5.10
(6)	Transformers		
	25 KVA - Single Phase	EACH	1,996.00
	50 KVA - Single Phase	EACH	2,580.00
	100 KVA - Single Phase	EACH	4,977.00
	3-25 KVA - Three Phase	EACH	7,201.00
	3-50 KVA - Three Phase	EACH	8,952.00
	3-100 KVA - Three Phase	EACH	15,308.00
(7)	Street Light Luminaire	EACH	617.00

* Joint Pole Line Cost To Be Used = $8.71/2 = $4.36

(Continued)

DRAFT

GENERAL INFORMATION

**No. 17 EXTENSION OF LINES AND FACILITIES (Continued)
APPENDIX A**

EXHIBIT IV
METERING COSTS

METER TYPE	TOTAL COST
Residential	
120/240 - Single Phase	$159.20
120/208 - Single Phase	161.06
Current Transformer - 120/240 - Single Phase	836.68
Other*	
Non-residential	
120/240 - Single Phase	159.20
120/208 - Single Phase	161.06
120/240 - Single Phase - Demand Metered	159.85
120/208 - Single Phase - Demand Metered	159.20
Other Secondary - Self-Contained - Secondary	159.20
Up to 1200 AMP – Current Transformer – Less than 480 Volts	1,430.48
Greater Than 1200 AMP – Current Transformer – Less than 480 Volts	1,430.48
Up to 1200 AMP – Current Transformer – 480 Volts	1,480.48
Greater Than 1200 AMP – Current Transformer – 480 Volts	1,480.48

* Cost to be determined on a case-by-case basis.

DRAFT

GENERAL INFORMATION
SERVICE CLASSIFICATION RIDER (Continued)

STANDBY SERVICE

Standby Service will be furnished when and where available to demand billed customers served under Service Classification No. 2 or 7 with on-site generation equipment or other source of electric service under the following conditions:

(a) Customer's on-site generation or other source of electric service equipment meet the requirements of Section 201 and Section 210 of the Public Utilities Regulatory Policies Act and regulations promulgated thereunder for a qualifying facility or the customer's generator meets the definition of distributed generation as defined in N.J.S.A. 48:2-21.37 .

(b) The customer agrees to abide by all provisions of the Company's "Operating, Metering, and Equipment Protection Requirements for Parallel Operation of Generating Facilities."

(c) The customer shall pay for any special metering costs. Special metering costs shall be defined as the total cost of metering less the cost of metering for service under the customer's Service Classification for customers without on-site generation.

(d) The standby capacity for a customer whose total generation capacity (nameplate ratings) is greater than said customer's total demand requirements shall be the amount of standby capacity, in kW, requested by said customer but not less than said customer's maximum demand as metered by the Company in any previous month. The standby capacity for all other customers shall be the nameplate rating, in kW, of all the customer's generation facilities interconnected with the Company's system, as determined by the Company.

(e) The customer shall notify the Company of all changes in customer's generating facilities prior to making such changes and shall allow the Company's representatives access to those facilities for purposes of inspection and redetermination of the standby capacity.

(f) The customer shall pay to the Company a standby capacity charge of $1.55 per kW of standby capacity per month. The standby capacity charge will be included in customer's bill for service rendered under Service Classification No. 2 or No. 7.

(g) In any month where the availability factor of the customer's generation facilities, as defined in (i), is lower than 50%, then the customer will not be eligible to take service under this Rider and the customer will not be charged the standby capacity charge described in (f).

(Continued)

DRAFT

GENERAL INFORMATION
SERVICE CLASSIFICATION RIDER (Continued)

STANDBY SERVICE (Continued)

(h) In any month where the availability factor of the customer's generation facilities, as defined in (i), is 50% or greater, the customer will pay for all the rates and charges contained in Service Classification No. 2 or No. 7; however, the Distribution Demand Charge shall be calculated based on the billing demand as provided for in the provision in Service Classification No. 2 or No. 7 entitled “DETERMINATION OF DEMAND” minus the customer’s standby capacity. For Service Classification No. 7 customers, this calculation will be performed for each rating period. In no event shall any billing demand be less than zero kW.

(i) For purposes of item (g) above, the availability factor of customer’s facilities shall be defined as the total energy (in kWh) produced by the facilities in the six month period ended with the current billing period (less the energy produced during mutually agreed upon maintenance periods) divided by (i) the number of hours in that period (less the number of hours in the mutually agreed upon maintenance periods) and (ii) the nameplate rating, in kW, of the customer’s generation facilities. During each of the first five billing periods for each customer, the availability factor shall be determined using the data that are available since the customer first commenced service hereunder.

DRAFT

SERVICE CLASSIFICATION NO. 1
RESIDENTIAL SERVICE

APPLICABLE TO USE OF SERVICE FOR

Sales and delivery of electric power supply provided by the Company or delivery of electric power supply provided by an electric generation supplier under the Company's Retail Access Program to residential customers. All service at each residence shall be taken through one meter. Service will also be furnished hereunder to a church and adjacent buildings (other than school buildings which substitute for public education), owned by the church and operated in connection therewith; provided, however, that if the buildings of any such church group are separated by a highway or highways, then the electricity delivered to each group so separated shall not be combined with the electricity delivered to other buildings of the church group but shall be billed separately under this rate.

CHARACTER OF SERVICE

Continuous, 60 cycle, A.C., from any of the following systems as designated by the Company:

(1) Single phase at approximately 120,120/208 or 120/240 volts.

(2) Three phase four wire at approximately 120/208 volts in limited areas.

RATE – MONTHLY

		Summer Months*	Other Months
(1)	Customer Charge	$6.50	$6.50
(2)	Distribution Charge		
	First 600 kWh	@ 6.165 ¢ per kWh	6.165 ¢ per kWh
	Over 600 kWh	@ 7.765 ¢ per kWh	6.165 ¢ per kWh

* Definition of Summer Billing Months - June through September

(Continued)

SERVICE CLASSIFICATION NO. 1
RESIDENTIAL SERVICE (Continued)

RATE – MONTHLY (Continued)

(5) Basic Generation Service

Customers taking Basic Generation Service from the Company will be billed for such service in accordance with General Information Section No. 31.

In accordance with Riders CBT and SUT, the charges in this Rate Schedule include provision for the New Jersey Corporation Business Tax and the New Jersey Sales and Use Tax. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT and SUT, such charges will be reduced by the relevant amount of such taxes included therein.

MINIMUM CHARGE EACH CONTRACT EACH LOCATION

$6.50 monthly, not less than $39.00 per contract.

TERMS OF PAYMENT

Bills are due in accordance with General Information Section No. 10.

TERM

Terminable at any time unless a specified period is required under a line extension agreement.

EXTENSION OF FACILITIES

Where service is supplied from an extension the charges thereon shall be determined as provided in General Information.

(Continued)

DRAFT

SERVICE CLASSIFICATION NO. 2
GENERAL SERVICE

APPLICABLE TO USE OF SERVICE FOR

Sales and delivery of electric power supply provided by the Company or delivery of electric power supply provided by an electric generation supplier under the Company's Retail Access Program to general secondary or primary service customers.

A customer taking primary service whose demand exceeds 1,000 kW during any two of the previous twelve months shall not be eligible for this rate and shall be transferred to Service Classification No. 7. A customer so transferred shall only be eligible for transfer back to Service Classification No. 2 on the annual anniversary of the transfer to Service Classification No. 7 and only if said customer has not exceeded 1,000 kW during any two of the previous twelve months.

All service at one location shall be taken through one meter except that service under Special Provision B shall be separately metered.

Demand billed customers with on-site generation or other sources of electric service equipment that meet the requirements of Section 201 and Section 210 of the Public Utilities Regulatory Policies Act and regulations promulgated thereunder for a qualifying facility or customers with generators that meet the definition of distributed generation as defined in N.J.S.A. 48:2-21.37 shall be subject to the provisions of Service Classification Rider – Standby Service.

CHARACTER OF SERVICE

Continuous, 60 cycle, A.C., single or three phase secondary, at approximately 120/208, 120/240 volts, and 277/480 volts where available; or three phase primary at approximately 2400/4160 and 7620/13200 volts Wye, 13000 and 34500 volts Delta, 69000 volts Wye, and in limited areas 2400 or 4800 volts Delta, depending upon the magnitude and characteristics of the load and the circuit from which service is supplied.

RATE – MONTHLY

	Summer Months*	Other Months
(1) Customer Charge		
(a) Secondary Service (Non-Demand Billed)		
Unmetered Service	$14.00	$14.00
Metered Service	$16.00	$16.00
(b) Secondary Service (Demand Billed)	$21.01	$21.01
(c) Primary Service	$92.00	$92.00

* Definition of Summer Billing Months - June through September

(Continued)

DRAFT

SERVICE CLASSIFICATION NO. 2
GENERAL SERVICE (Continued)

RATE – MONTHLY (Continued)

			Summer Months*	Other Months
(2)	Distribution Charges			
(a)	Secondary Service (Non-Demand Billed)			
	Usage Charge			
	All kWh	........@	4.328 ¢ per kWh	3.922 ¢ per kWh
(b)	Secondary Service (Demand Billed)			
	Demand Charge			
	First 5 kW	........@	$4.53 per kW	$3.79 per kW
	Over 5 kW	........@	$7.12 per kW	$6.00 per kW
	Usage Charge			
	First 4,920 kWh	........@	3.271 ¢ per kWh	3.088 ¢ per kWh
	Over 4,920 kWh	........@	2.856 ¢ per kWh	2.795 ¢ per kWh
(c)	Primary Service			
	Demand Charge			
	All kW	........@	$7.70 per kW	$6.60 per kW
	Usage Charge			
	All kWh	……....@	1.485 ¢ per kWh	1.485 ¢ per kWh

* Definition of Summer Billing Months - June through September

(Continued)

SERVICE CLASSIFICATION NO. 2
GENERAL SERVICE (Continued)

RATE – MONTHLY (Continued)

(5) CIEP Standby Fee

In accordance with General Information Section No. 32, a CIEP Standby Fee shall be assessed on all kWh of customers eligible for BGS-CIEP service.

(6) Basic Generation Service

Customers taking Basic Generation Service from the Company will be billed for such service in accordance with General Information Section No. 31.

In accordance with Riders CBT and SUT, the charges in this Rate Schedule include provision for the New Jersey Corporation Business Tax and the New Jersey Sales and Use Tax. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT and SUT, such charges will be reduced by the relevant amount of such taxes included therein.

MINIMUM MONTHLY CHARGE

Secondary Service (Non-Demand Billed)		
Unmetered Service	$14.00	
Metered Service	$16.00	
Secondary Service (Demand Billed)	$21.01	Plus the demand charge.
Primary Service	$92.00	Plus the demand charge.

DETERMINATION OF DEMAND

The monthly billing demand in kW shall be either the greatest connected load or the greatest 15-minute integrated demand, determined as follows:

(1) Billing demand may be on a connected load basis when

(a) demand meter would not reduce the billing demand, or

(b) the installation is temporary, or

(c) the device has a large instantaneous or highly fluctuating demand.

(2) Billing shall be on a demand meter basis in all other cases and shall be billed at not less than 90% of the kVA demand. The billing demand for the billing months of October through May inclusive shall not be less than 70% of the highest metered demand for the preceding billing months of June through September inclusive.

(Continued)

SERVICE CLASSIFICATION NO. 2
GENERAL SERVICE (Continued)

SPECIAL PROVISIONS

(A) Short Term Secondary Service

When short term service is requested, the Company reserves the right to require a deposit of the estimated bill for the period service is desired. The minimum charge for such short term service shall be an amount equal to six times the minimum monthly charge, payable in advance. When construction is necessary, the cost of installation and removal of all equipment, less salvage value, shall be borne by the customer, and a sufficient amount to cover these charges shall be paid in advance. A part of a month shall be considered a full month for computing all charges hereunder.

(B) Space Heating

Customers who take service under this classification for 10 kW or more of permanently installed space heating equipment may elect to have the electricity for this service billed separately. All monthly use shall be billed at a Distribution Charge of 3.779 ¢/kWh during the billing months of October through May and 6.295 ¢/kWh during the summer billing months. When this option is requested it shall apply for at least 12 months and shall be subject to a minimum charge of $26.87 per year per kW of space heating capacity. This provision applies for both heating and cooling where the two services are combined by the manufacturer in a single self-contained unit.

All usage under this Special Provision shall also be subject to Parts (3), (4), and (6) of RATE – MONTHLY.

This special provision is closed to new customers effective August 1, 2014.

(Continued)

DRAFT

SERVICE CLASSIFICATION NO. 2
GENERAL SERVICE (Continued)

SPECIAL PROVISIONS (Continued)

(C) Budget Billing Plan

Any condominium association or cooperative housing corporation who takes service hereunder and any other customer taking service under Special Provision B of this Service Classification may, upon request, be billed monthly in accordance with the budget billing plan provided for in General Information Section 8 of this tariff.

(D) Veterans' Organization Service

Pursuant to N.J.S.A. 48:2-21.41, when electric service is delivered to a customer that is a Veterans' Organization that is serving the needs of veterans of the armed forces, the customer may apply and be eligible for billing under this Special Provision.

Each customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this Service Classification and by qualifying as a Veterans' Organization as defined by N.J.S.A. 48:2-21.41 as "an organization dedicated to serving the needs of veterans of the armed forces that: is chartered under federal law, qualifies as a tax exempt organization under paragraph (19) of subsection (c) of section 501 of the federal Internal Revenue Code of 1986, 26 U.S.C. s.501 (c)(19), or that is organized as a corporation under the 'New Jersey Nonprofit Corporation Act,' N.J.S.15A:1-1 et seq." Under N.J.S.A. 48: 2-21.41, a qualified Veterans' Organization shall be charged the residential rate for service delivered to the property where the Veterans' Organization primarily operates, if the residential rate is lower than the commercial rate for service at that property.

The customer shall furnish satisfactory proof of eligibility for service under this Special Provision to the Company. Once proof of eligibility is determined by the Company, service under this Special Provision shall begin with the next billing cycle following receipt of the Application.

(Continued)

SERVICE CLASSIFICATION NO. 2
GENERAL SERVICE (Continued)

SPECIAL PROVISIONS (Continued)

(D) Veterans' Organization Service (Continued)

The customer will continue to be billed on this Service Classification. At least once annually, the Company shall review eligible customers' distribution charges under this Special Provision for all relevant periods. If the comparable distribution charges under Service Classification No. 1 are lower than the distribution charges under the customer's current Service Classification, a credit in the amount of the difference will be applied to the customer's next bill.

SERVICE CLASSIFICATION NO. 3
RESIDENTIAL TIME-OF-DAY SERVICE

APPLICABLE TO USE OF SERVICE FOR

Sales and delivery of electric power supply provided by the Company or delivery of electric power supply provided by an electric generation supplier under the Company's Retail Access Program to residential customers, at customer's option.

CHARACTER OF SERVICE

Continuous, 60 cycle, A.C., from any of the following systems as designated by the Company:

(1) Single phase at approximately 120,120/208 or 120/240 volts.

(2) Three phase four wire at approximately 120/208 volts in limited areas.

RATE – MONTHLY

		Summer Months*	Other Months
(1)	Customer Charge	$9.00	$9.00
(2)	Distribution Charge		
	Peak All kWh measured between 10:00 a.m. and 10:00 p.m., Monday through Friday ....@	8.463 ¢ per kWh	7.592 ¢ per kWh
	Off-Peak All other kWh ....@	3.048 ¢ per kWh	3.048 ¢ per kWh

* Definition of Summer Billing Months - June through September

(Continued)

DRAFT

SERVICE CLASSIFICATION NO. 3
RESIDENTIAL TIME-OF-DAY SERVICE (Continued)

RATE – MONTHLY (Continued)

(3) Transmission Charge

(a) These charges apply to all customers taking Basic Generation Service from the Company. These charges are also applicable to customers located in the Company's Central and Western Divisions and obtaining Competitive Energy Supply. These charges are not applicable to customers located in the Company's Eastern Division and obtaining Competitive Energy Supply. The Company's Eastern, Central and Western Divisions are defined in General Information Section No. 1.

	Summer Months*	Other Months
Peak All kWh measured between 10:00 a.m. and 10:00 p.m., Monday through Friday ......@	1.583 ¢ per kWh	1.583 ¢ per kWh
Off-Peak All other kWh ......@	1.583 ¢ per kWh	1.583 ¢ per kWh

(b) Transmission Surcharge – This charge is applicable to all customers taking Basic Generation Service from the Company and includes surcharges related to Reliability Must Run, EL05-121 Settlement and Transmission Enhancement Charges.

All kWh .....@	1.137 ¢ per kWh	1.137 ¢ per kWh

(4) Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, Securitization Charges, Temporary Tax Act Credit, and Zero Emission Certificate Recovery Charge.

The provisions of the Company's Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, Securitization Charges, Temporary Tax Act Credit, and Zero Emission Certificate Recovery Charge as described in General Information Section Nos. 33, 34, 35, 36, and 37 respectively, shall be assessed on all kWh delivered hereunder.

* Definition of Summer Billing Months - June through September

(Continued)

DRAFT

SERVICE CLASSIFICATION NO. 3
RESIDENTIAL TIME-OF-DAY SERVICE (Continued)

RATE – MONTHLY (Continued)

(5) Basic Generation Service

Customers taking Basic Generation Service from the Company will be billed for such service in accordance with General Information Section No. 31.

In accordance with Riders CBT and SUT, the charges in this Rate Schedule include provision for the New Jersey Corporation Business Tax and the New Jersey Sales and Use Tax. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT and SUT, such charges will be reduced by the relevant amount of such taxes included therein.

MINIMUM CHARGE EACH CONTRACT EACH LOCATION

The Customer Charge, not less than $108.00 per contract.

TERMS OF PAYMENT

Bills are due in accordance with General Information Section No. 10.

TERM

The initial term of service shall be one year. Customers opting for this rate shall not be entitled to service at the same location under the Company's Service Classification Nos. 1 or 5 until one year from the date of service or thereafter on the annual anniversary date upon 5 days' prior written notice.

EXTENSION OF FACILITIES

Where service is supplied from an extension the charges thereon shall be determined as provided in General Information.

(Continued)

DRAFT

SERVICE CLASSIFICATION NO. 3
RESIDENTIAL TIME-OF-DAY SERVICE (Continued)

SPECIAL PROVISIONS

(A) Metering

The customer shall guarantee the Company access to the meter at all times. In the event the Company is unable to obtain the necessary meter readings, it shall estimate the consumption based on all the data available and apply the rates as specified in RATE – MONTHLY.

(B) Budget Billing

Not available under this Service Classification.

DRAFT

SERVICE CLASSIFICATION NO. 4
PUBLIC STREET LIGHTING SERVICE (Continued)

RATE – MONTHLY

(1) Distribution and Transmission Charges

(a) Distribution Luminaire Charges

Nominal Lumens	Luminaire Type	Watts	Total Wattage	Distribution Charge
Street Lighting Luminaires				
5,800	Sodium Vapor	70	108	$9.47
9,500	Sodium Vapor	100	142	10.28
16,000	Sodium Vapor	150	199	12.51
27,500	Sodium Vapor	250	311	15.96
46,000	Sodium Vapor	400	488	25.89
3,000	LED	20-25	23	8.21
3,900	LED	30-39	35	8.05
5,000	LED	40-59	50	8.07
7,250	LED	60-79	68	8.41
12,000	LED	95-110	103	9.46
16,000	LED	130-150	140	9.92
22,000	LED	180-220	200	14.53
Flood Lighting Luminaires				
15,500	LED	115-130	125	$11.43
27,000	LED	175-225	205	14.58
37,500	LED	265-315	290	15.88

The following luminaires will no longer be installed. Charges are for existing luminaires only.

Street Lighting Luminaires				
1,000	Open Bottom Incandescent	92	92	$6.27
4,000	Mercury Vapor	100	127	8.49
7,900	Mercury Vapor	175	211	10.00
12,000	Mercury Vapor	250	296	13.00
22,500	Mercury Vapor	400	459	16.51
40,000	Mercury Vapor	700	786	25.10
59,000	Mercury Vapor	1,000	1,105	31.72

(Continued)

DRAFT

SERVICE CLASSIFICATION NO. 4
PUBLIC STREET LIGHTING SERVICE (Continued)

RATE – MONTHLY (Continued)

(1) Distribution and Transmission Charges (Continued)

(a) Distribution Luminaire Charges (Continued)

Nominal Lumens	Luminaire Type	Watts	Total Wattage	Distribution Charge
Street Lighting Luminaires (Continued)				
3,400	Induction	40	45	$9.91
5,950	Induction	70	75	10.09
8,500	Induction	100	110	11.39
5,890	LED	70	74	10.84
9,365	LED	100	101	13.32
Post-Top Luminaires				
4,000	Mercury Vapor	100	130	$12.90
7,900	Mercury Vapor	175	215	15.81
7,900	Merc. Vapor-Offset	175	215	18.57
16,000	Sod. Vapor-Offset	150	199	25.27

(b) Transmission Charges

A Transmission Charge of 1.280 ¢ per kWh will apply to all customers taking Basic Generation Service from the Company. Transmission charges are also applicable to customers located in the Company's Central and Western Divisions and obtaining Competitive Energy Supply. Transmission charges are not applicable to customers located in the Company's Eastern Division and obtaining Competitive Energy Supply. The Company's Eastern, Central and Western Divisions are defined in General Information Section No. 1. A Transmission Surcharge, to recover Reliability Must Run Charges, of 0.001 ¢ per kWh will also apply to all customers taking Basic Generation Service from the Company.

Transmission Charges shall be applied to the kWh estimate in the following manner:

kWh = (Total Wattage divided by 1,000) times Monthly Burn Hours*

*See Monthly Burn Hours Table

(Continued)

SERVICE CLASSIFICATION NO. 4
PUBLIC STREET LIGHTING SERVICE (Continued)

RATE – MONTHLY (Continued)

(2) Additional Charge

(a) An additional $21.60 per luminaire per month will be charged for existing Underground Service where the Company owns and maintains the entire facilities.

(b) An additional $5.26 per luminaire per month will be charged for existing underground service where the customer has installed, owns and maintains the duct system complete, but not the aluminum standard or luminaire.

(c) An additional $0.59 per bracket per month will be charged for a fifteen foot bracket when installed.

(3) Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, Securitization Charges, Temporary Tax Act Credit, and Zero Emission Certificate Recovery Charge.

The provisions of the Company's Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, Securitization Charges, Temporary Tax Act Credit, and Zero Emission Certificate Recovery Charge as described in General Information Section Nos. 33, 34, 35, 36, and 37 respectively shall be assessed on all kWh delivered hereunder.

The charges shall be applied to the kWh estimate in the following manner:

kWh = (Total Wattage divided by 1,000) times Monthly Burn Hours*

* See Monthly Burn Hours Table.

(Continued)

DRAFT

SERVICE CLASSIFICATION NO. 5
RESIDENTIAL SPACE HEATING SERVICE

APPLICABLE TO USE OF SERVICE FOR

Sales and delivery of electric power supply provided by the Company or delivery of electric power supply provided by an electric generation supplier under the Company's Retail Access Program to residential customers, where electricity is a source of space heating subject to the conditions specified in "Special Provisions". All service at each residence shall be taken through one meter.

CHARACTER OF SERVICE

Continuous, 60 cycle, A.C., from any of the following systems as designated by the Company:

(1) Single phase at approximately 120,120/208 or 120/240 volts.

(2) Three phase four wire at approximately 120/208 volts in limited areas.

RATE – MONTHLY

			Summer Months*	Other Months
(1)	Customer Charge		$6.50	$6.50
(2)	Distribution Charge			
	First 600 kWh	..........@	6.165 ¢ per kWh	6.165 ¢ per kWh
	Over 600 kWh	..........@	7.765 ¢ per kWh	6.165 ¢ per kWh

*Definition of Summer Billing Months - June through September

(Continued)

ISSUED: EFFECTIVE:

ISSUED BY: Robert Sanchez, President
Mahwah, New Jersey 07430

SERVICE CLASSIFICATION NO. 5
RESIDENTIAL SPACE HEATING SERVICE (Continued)

RATE – MONTHLY (Continued)

(5) Basic Generation Service

Customers taking Basic Generation Service from the Company will be billed for such service in accordance with General Information Section No. 31.

In accordance with Riders CBT and SUT, the charges in this Rate Schedule include provision for the New Jersey Corporation Business Tax and the New Jersey Sales and Use Tax. When billed to customers exempt from one or more customers exempt from one or more of these taxes, as set forth in Riders CBT and SUT, such charges will be reduced by the relevant amount of such taxes included therein.

MINIMUM CHARGE EACH CONTRACT EACH LOCATION

$6.50 monthly, not less than $39.00 per contract.

TERMS OF PAYMENT

Bills are due in accordance with General Information Section No. 10.

TERM

Terminable at any time unless a specified period is required under a line extension agreement.

EXTENSION OF FACILITIES

Where service is supplied from an extension the charges thereon shall be determined as provided in General Information.

(Continued)

DRAFT

SERVICE CLASSIFICATION NO. 6
PRIVATE OVERHEAD LIGHTING SERVICE (Continued)

RATE – MONTHLY:

(1) Distribution and Transmission Charges

(a) Luminaire Charges for Service Types A and B

Nominal Lumens	Luminaire Type	Watts	Total Wattage	Distribution Charge
Power Bracket Luminaires				
5,800	Sodium Vapor	70	108	$7.51
9,500	Sodium Vapor	100	142	9.02
16,000	Sodium Vapor	150	199	9.68
3,950	LED	30-44	35	7.57
5,550	LED	45-49	50	7.68
7,350	LED	60-70	65	7.75
Street Lighting Luminaires				
5,800	Sodium Vapor	70	108	$10.45
9,500	Sodium Vapor	100	142	11.46
16,000	Sodium Vapor	150	199	14.09
27,500	Sodium Vapor	250	311	18.07
46,000	Sodium Vapor	400	488	29.83
3,000	LED	20-25	23	8.21
3,900	LED	30-39	35	8.05
5,000	LED	40-59	50	8.07
7,250	LED	60-79	68	8.41
12,000	LED	95-110	103	9.46
16,000	LED	130-150	140	9.92
22,000	LED	180-220	200	14.53
Flood lighting Luminaires				
46,000	Sodium Vapor	400	488	$29.83
15,500	LED	115-130	125	11.43
27,000	LED	175-225	205	14.58
37,500	LED	265-315	290	15.88

(Continued)

DRAFT

SERVICE CLASSIFICATION NO. 6
PRIVATE OVERHEAD LIGHTING SERVICE (Continued)

RATE – MONTHLY (Continued)

(1) Distribution and Transmission Charges (Continued)

(a) Luminaire Charges for Service Types A and B (Continued)

Nominal Lumens	Luminaire Type	Watts	Total Wattage	Distribution Charge

The following luminaires will no longer be installed. Charges are for existing luminaires only.

Power Bracket Luminaires

4,000	Mercury Vapor	100	127	$11.66
7,900	Mercury Vapor	175	215	13.48
22,500	Mercury Vapor	400	462	21.48

Post Top Luminaires

16,000	Sod. Vapor-Offset	150	199	$27.73

Street Lighting Luminaires

4,000	Mercury Vapor	100	127	$12.82
7,900	Mercury Vapor	175	211	14.64
22,500	Mercury Vapor	400	459	22.75
1,000	Incandescent	-	92	10.42
3,400	Induction	40	45	11.24
5,950	Induction	70	75	11.48
8,500	Induction	100	110	12.93
5,890	LED	70	74	12.30
9,365	LED	100	101	15.14

Flood lighting Luminaires

12,000	Mercury Vapor	250	296	$18.42
40,000	Mercury Vapor	700	786	33.35
59,000	Mercury Vapor	1,000	1,105	41.53

(Continued)

DRAFT

SERVICE CLASSIFICATION NO. 6
PRIVATE OVERHEAD LIGHTING SERVICE (Continued)

RATE – MONTHLY (Continued)

(1) Distribution and Transmission Charges (Continued)

(b) Distribution Charges for Service Type C

Metered Service - Customer Charge at $14.00 per month plus Distribution Charge at 6.251 ¢ per kWh; or

Unmetered Service - Customer Charge at $3.00 per month plus Distribution Charge at 6.251 ¢ per kWh.

(c) Transmission Charges for Service Types A, B, and C

A Transmission Charge of 1.280 ¢ per kWh will apply to all customers taking Basic Generation Service from the Company. Transmission charges are also applicable to customers located in the Company's Central and Western Divisions and obtaining Competitive Energy Supply. Transmission charges are not applicable to customers located in the Company's Eastern Division and obtaining Competitive Energy Supply. The Company's Eastern, Central and Western Divisions are defined in General Information Section No. 1. A Transmission Surcharge, to recover Reliability Must Run Charges, of 0.001 ¢ per kWh will also apply to all customers taking Basic Generation Service from the Company.

For service type A, B, or C if not metered, the charges shall be applied to the kWh estimated as follows:

kWh = (Total Wattage divided by 1,000) times Monthly Burn Hours*

(2) Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, Securitization Charges, Temporary Tax Act Credit, and Zero Emission Certificate Recovery Charge.

The provisions of the Company’s Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, Securitization Charges, Temporary Tax Act Credit, and Zero Emission Certificate Recovery Charge as described in General Information Section Nos. 33, 34, 35, 36, and 37 respectively shall be assessed on all kWh delivered hereunder. For service type A, B, or C if not metered, the charges shall be applied to the kWh estimated as follows:

kWh = (Total Wattage divided by 1,000) times Monthly Burn Hours*

* See Monthly Burn Hours Table.

(Continued)

SERVICE CLASSIFICATION NO. 6
PRIVATE OVERHEAD LIGHTING SERVICE (Continued)

MINIMUM CHARGE

The minimum charge per luminaire for Service Type A or B shall be the sum of the monthly Distribution and Transmission Charges as specified in RATE – MONTHLY, Part (1a) times twelve. Should the monthly charge be revised during the initial term, the minimum charge per installation shall be prorated accordingly.

The minimum charge for Service Type C - Metered shall be $14.00 per month and not less than $168.00 for the initial term.

The minimum charge for Service Type C - Unmetered shall be $3.00 per month and not less than $36.00 for the initial term.

TERM

The Initial Term shall be one year. Service shall continue in effect thereafter until canceled by either party upon thirty days written notice. The Company shall require an Initial Term of one year for each luminaire for Service Types A or B.

TERMS OF PAYMENT

Bills are due in accordance with General Information Section No. 10.

(Continued)

SERVICE CLASSIFICATION NO. 6
PRIVATE OVERHEAD LIGHTING SERVICE (Continued)

SPECIAL PROVISIONS

Special Provisions A, B, D, E, F, and J apply only to Service Types A and B. Special Provision K applies only to Service Type C. Special Provisions C, G, H, and I apply to Service Types A, B, and C.

(A) Street lighting luminaires will normally be mounted on eight foot aluminum brackets. Fifteen foot brackets are available at an additional charge of $0.74 per bracket per month.

(B) Luminaires will be installed free of charge where all facilities necessary to serve a luminaire are present. Customer shall pay the cost of any additional facilities required, prior to the commencement of the construction of such facilities.

(C) The customer shall furnish the Company with all easements or rights-of-way necessary to provide service to the desired location before any installation or construction will be started.

(D) A customer may apply for service hereunder for a proposed residential subdivision in which all electric facilities will be underground. Such application shall be signed by the customer and builder or developer and when accepted by the Company, shall constitute an agreement between the Company, customer and builder or developer subject to the terms and provisions hereunder.

The builder or developer shall pay to the Company prior to the commencement of any construction all costs associated with the installation of the facilities to be serviced hereunder and shall prepay six times the total monthly charge for all luminaires installed. Said monthly charges shall be determined using the rates in effect at the time said costs and charges are determined. The Company shall not bill the customer for the first six months of service of the facilities installed under this special provision.

(E) The Company shall not be obligated to repair or replace in kind any obsolete luminaire for which it cannot reasonably obtain the necessary parts. The Company will remove the obsolete luminaire or at the customer's request, replace it with any luminaire offered for service at that time for which the customer will be charged the appropriate rates.

(Continued)

SERVICE CLASSIFICATION NO. 7
LARGE GENERAL TIME-OF-DAY SERVICE

APPLICABLE TO USE OF SERVICE FOR

Sales and delivery of electric power supply provided by the Company or delivery of electric power supply provided by an electric generation supplier under the Company's Retail Access Program to primary service customers who maintain a minimum demand of 1,000 kW during any two of the previous twelve months and provide all equipment required to take service at a primary voltage as designated by the Company. A primary customer who does not maintain a demand of at least 1,000 kW during any two of the previous twelve months, may, at the customer's option transfer to another Service Classification provided that such transfer shall only be made on an annual anniversary date that such customer began service hereunder.

Sales and delivery of electric power supply provided by the Company or delivery of electric power supply provided by an electric generation supplier under the Company's Retail Access Program to high voltage distribution service customers with a minimum demand of 1,000 kW who provide all equipment required to take high voltage distribution service as designated by the Company. High voltage distribution service shall be made available at the sole discretion of the Company where conditions merit.

Customers with on-site generation or other sources of electric service equipment that meet the requirements of Section 201 and Section 210 of the Public Utilities Regulatory Policies Act and regulations promulgated thereunder for a qualifying facility or customers with generators that meet the definition of distributed generation as defined in N.J.S.A. 48:2-21.37 shall be subject to the provisions of Service Classification Rider – Standby Service.

All service at one location shall be taken through one meter except that service taken under Special Provision A shall be separately metered.

CHARACTER OF SERVICE

Continuous, 60 cycles, A.C., single or three phase primary or high voltage distribution service as defined in General Information Section 26 and depending on the magnitude and characteristics of the load and the circuit from which service is supplied.

RATE – MONTHLY

	Primary	High Voltage Distribution
(1) Customer Charge	$250.00	$2,288.12

(Continued)

DRAFT

SERVICE CLASSIFICATION NO. 7
LARGE GENERAL TIME-OF-DAY SERVICE (Continued)

RATE – MONTHLY (Continued)

(2) Distribution Charges

		Primary	High Voltage Distribution
Demand Charge			
Period I	All kW @	$3.88 per kW	$1.10 per kW
Period II	All kW @	0.96 per kW	0.26 per kW
Period III	All kW @	3.56 per kW	1.01 per kW
Period IV	All kW @	0.96 per kW	0.26 per kW
Usage Charge			
Period I	All kWh @	1.770 ¢ per kWh	0.203 ¢ per kWh
Period II	All kWh @	1.325 ¢ per kWh	0.151 ¢ per kWh
Period III	All kWh @	1.770 ¢ per kWh	0.203 ¢ per kWh
Period IV	All kWh @	1.325 ¢ per kWh	0.151 ¢ per kWh

(3) Transmission Charges

(a) These charges apply to all customers taking Basic Generation Service from the Company. These charges are also applicable to customers located in the Company's Central and Western Divisions and obtaining Competitive Energy Supply. These charges are not applicable to customers located in the Company's Eastern Division and obtaining Competitive Energy Supply. The Company's Eastern, Central and Western Divisions are defined in General Information Section No. 1.

(Continued)

SERVICE CLASSIFICATION NO. 7
LARGE GENERAL TIME-OF-DAY SERVICE (Continued)

SPECIAL PROVISIONS

(A) Space Heating

Customers who take service under this classification for 10 kW or more of permanently installed space heating equipment may elect to have the electricity for this service billed separately. All monthly use shall be billed at a Distribution Charge of 4.081 ¢ per kWh during the billing months of October through May and 6.597 ¢ per kWh during the summer billing months, a Transmission Charge of 0.421 ¢ per kWh and a Transmission Surcharge of 0.656 ¢ per kWh during all billing months. The applicability of Transmission Charges and the Transmission Surcharge is described in Part (3) of RATE – MONTHLY.

When this option is requested it shall apply for at least 12 months and shall be subject to a minimum charge of $26.87 per year per kW of space heating capacity. This provision applies for both heating and cooling where the two services are combined by the manufacturer in a single self-contained unit.

All usage under this Special Provision shall also be subject to Parts (4), (5), and (6) of RATE – MONTHLY. This Special Provision is not available to those customers taking high voltage distribution service.

This special provision is closed to new customers effective August 1, 2014.

(B) Budget Billing Plan

Any condominium association or cooperative housing corporation who takes service hereunder and any other customer taking service under Special Provision B of this Service Classification may, upon request, be billed monthly in accordance with the budget billing plan provided for in General Information Section 8 of this tariff.

(Continued)

DRAFT

SERVICE CLASSIFICATION NO. 7
LARGE GENERAL TIME-OF-DAY SERVICE (Continued)

This leaf intentionally left blank.

SERVICE CLASSIFICATION NO. 7
LARGE GENERAL TIME-OF-DAY SERVICE (Continued)

This leaf intentionally left blank.

DRAFT

TABLE OF CONTENTS (Continued)

(Continued)

DRAFT

GENERAL INFORMATION

No. 17 EXTENSION OF LINES AND FACILITIES (Continued)
APPENDIX A

EXHIBIT I
UNIT COSTS OF UNDERGROUND CONSTRUCTION
SINGLE PHASE

	ITEM	UNIT	TOTAL COST
(1)	Trenching	PER FOOT	$~~13.91~~11.70*
	Pavement Cutting and Restoration	PER FOOT	~~28.35~~28.98
	Blasting and Rock Removal	PER FOOT	ACTUAL LOW BID
	Jack Hammering and Rock Removal	PER FOOT	ACTUAL LOW BID
(2)	Primary Cable (#2 Aluminum)	PER FOOT	~~3.33~~5.26
(3)	Secondary Cable		
	(a) 4/0 AAC Triplex	PER FOOT	~~2.30~~3.93
	(b) 350 kcmil Aluminum	PER FOOT	~~4.20~~4.89
(4)	Service (Installed in conduit, includes tap on, does not include trenching) Up to 200 AMP	PER FOOT	~~13.50~~16.39
	Service (Installed in conduit, includes tap on, does not include trenching) Over 200 AMP	PER FOOT	~~15.40~~18.34

* Will be adjusted to reflect any contribution received from cable television companies.

(Continued)

DRAFT

GENERAL INFORMATION

No. 17 EXTENSION OF LINES AND FACILITIES (Continued)
APPENDIX A

EXHIBIT I
UNIT COSTS OF UNDERGROUND CONSTRUCTION
SINGLE PHASE (Continued)

	ITEM	UNIT	TOTAL COST
(5)	Primary Termination /Riser	EACH	$~~2,328.87~~2,109.00
	Secondary Termination/Riser	EACH	
	~~987.01~~1,105.00		
(6)	Primary Junction Enclosure		
	(a) Single Phase Boxpad - Unfused	EACH	~~2,064.45~~1,899.00
	(b) Single Phase Switch - Fused	EACH	~~9,097.69~~8,681.00
(7)	Secondary Enclosure		
	(Incl. Terminations)	EACH	~~661.99~~481.00
(8)	Conduit (2" Schedule 40 PVC, installed)	PER FOOT	~~2.93~~3.16
	Conduit (4" Schedule 40 PVC, installed)	PER FOOT	~~4.33~~4.84
(9)	Street Light Cable		
	#2 Triplex in Conduit	PER FOOT	~~4.61~~6.54
(10)	Transformers, Including Pad		
	25 KVA	EACH	~~4,543.59~~5,181,00
	50 KVA	EACH	~~5,060.79~~5,508.00
	75 KVA	EACH	~~6,757.92~~5,880.00
	100 KVA	EACH	~~7,185.21~~6,496.00
	167 KVA	EACH	~~8,627.92~~7,979.00
(11)	Street Lighting - U/G Feed		
	30' Pole (including arm & luminaire)	EACH	~~1,771.67~~2,127.69

(Continued)

DRAFT

GENERAL INFORMATION

No. 17 EXTENSION OF LINES AND FACILITIES (Continued)
APPENDIX A

EXHIBIT II
UNIT COSTS OF UNDERGROUND CONSTRUCTION
THREE PHASE

	ITEM	UNIT	TOTAL COST
(1)	Primary Cable Installation		
	(a) 750 kcmil – 600A	PER CIRCUIT FOOT	$~~101.42~~100.11
	(b) 350 kcmil – 400A	PER CIRCUIT FOOT	~~55.62~~57.54
	(c) 2/0 Cu – 200A	PER CIRCUIT FOOT	~~39.45~~31.37
(2)	Secondary Cable Installation		
	350 kmcil 4-Wire	PER CIRCUIT FOOT	~~9.37~~11.87
(3)	Service		
	350 kmcil AAC	PER CIRCUIT FOOT	~~22.09~~21.94
(4)	Primary Termination /Riser		
	(a) 750 kcmil – 600A	EACH	~~10,701.30~~1,123.00
	(b) 350 kcmil – 400A	EACH	~~7,686.56~~909.00
	(c) 2/0 Cu – 200A	EACH	~~4,324.27~~348.00
	(d) #2 Al – 100A	EACH	~~425.00~~340.00
(5)	Primary Junction Box		
	(a) 200 A Installation Only	EACH	~~3,488.65~~3,157.00
	(b) 2/0 AWG Termination	EACH	~~904.60~~273.00
	(c) # 2 AWG Termination	EACH	~~624.85~~277.00
(6)	Primary Switch - PMH FOR 400A OR 600A		
	(a) Switch Installation	EACH	~~24,529.07~~24,287.00
	(b) 750 kcmil Termination	EACH	~~2,955.45~~885.00
	(c) 350 kcmil Termination	EACH	~~2,148.93~~636.00
	(d) 2/0 AWG Termination	EACH	~~1,229.91~~348.00
	(e) #2 AWG Termination	EACH	~~943.53~~340.00

(Continued)

DRAFT

GENERAL INFORMATION

No. 17 EXTENSION OF LINES AND FACILITIES (Continued)
APPENDIX A

EXHIBIT II
UNIT COSTS OF UNDERGROUND CONSTRUCTION
THREE PHASE (Continued)

	ITEM	UNIT	TOTAL COST
(7)	Primary Switch - Elliot for 200A		
	(a) Switch Installation	EACH	$~~14,537.49~~16,900.00
	(b) 2/0 AWG Termination	EACH	~~1,768.77~~273.00
	(c) #2 AWG Termination	EACH	~~1,511.65~~277.00
(8)	Conduit		
	(4" Schedule 40 PVC, installed)	PER FOOT	~~4.33~~4.84
	(6" Schedule 40 PVC, installed)	PER FOOT	~~5.76~~6.75
(9)	Transformers, Including Pad		
	150 KVA	EACH	~~9,076.03~~14,137.00
	300 KVA	EACH	~~12,851.22~~16,911.63
(10)	Concrete Pullbox		
	Materials	EACH	~~11,084.27~~10,113.00
	Labor	EACH	ACTUAL LOW BID
(11)	Concrete Manhole		
	Materials	EACH	~~21,468.77~~19,733.00
	Labor	EACH	ACTUAL LOW BID
(12)	Trenching - Mainline Construction	PER FOOT	ACTUAL LOW BID

(Continued)

DRAFT

GENERAL INFORMATION

No. 17 EXTENSION OF LINES AND FACILITIES (Continued)
APPENDIX A

EXHIBIT III
UNIT COSTS OF OVERHEAD CONSTRUCTION
SINGLE PHASE AND THREE PHASE

	ITEM	UNIT	TOTAL COST
(1)	Pole Line (Includes 45 ft. Poles		
	Anchors & Guys)	PER FOOT	$~~8.71~~15.03*
(2)	Primary Wire		
	(a) Single Phase (3/0 ACSR)	PER FOOT	~~4.18~~5.31
	(b) Three Phase (477 kmcil Aluminum)	PER FOOT	~~14.43~~15.17
	(c) Three Phase (3/0 ACSR)	PER FOOT	~~11.79~~13.13
	(d) Neutral	PER FOOT	~~2.55~~3.34
(3)	Secondary Wire		
	(a) 3-Wire (2/0 TX)	PER FOOT	~~4.38~~6.26
	(b) 4-Wire (2/0 QX)	PER FOOT	~~4.98~~6.85
(4)	Service - Single Phase		
	Up To 200 AMP	PER FOOT	~~4.42~~3.73
	Over 200 AMP	PER FOOT	~~5.27~~4.54
(5)	Service - Three Phase		
	Up To 200 AMP	PER FOOT	~~5.29~~4.60
	Over 200 AMP	PER FOOT	~~5.89~~5.10
(6)	Transformers		
	25 KVA - Single Phase	EACH	~~1,804.88~~1,996.00
	50 KVA - Single Phase	EACH	~~2,262.53~~2,580.00
	100 KVA - Single Phase	EACH	~~3,177.36~~4,977.00
	3-25 KVA - Three Phase	EACH	~~6,139.71~~7,201.00
	3-50 KVA - Three Phase	EACH	~~7,511.76~~8,952.00
	3-100 KVA - Three Phase	EACH	~~10,024.90~~15,308.00
(7)	Street Light Luminaire	EACH	~~465.64~~617.00

* Joint Pole Line Cost To Be Used = $8.71/2 = $4.36

(Continued)

DRAFT

GENERAL INFORMATION

No. 17 EXTENSION OF LINES AND FACILITIES (Continued)
APPENDIX A

EXHIBIT IV
METERING COSTS

METER TYPE	TOTAL COST
Residential	
120/240 - Single Phase	$~~108.99~~159.20
120/208 - Single Phase	~~138.59~~161.06
Current Transformer - 120/240 - Single Phase	~~1,371.03~~836.68
Other*	
Non-residential	
120/240 - Single Phase	~~108.99~~159.20
120/208 - Single Phase	~~138.59~~161.06
120/240 - Single Phase - Demand Metered	~~160.66~~159.85
120/208 - Single Phase - Demand Metered	~~181.69~~159.20
Other Secondary - Self-Contained - Secondary	~~181.69~~159.20
Up to 1200 AMP – Current Transformer – Less than 480 Volts	~~1,496.59~~1,430.48
Greater Than 1200 AMP – Current Transformer – Less than 480 Volts	~~1,551.69~~1,430.48
Up to 1200 AMP – Current Transformer – 480 Volts	~~1,844.20~~1,480.48
Greater Than 1200 AMP – Current Transformer – 480 Volts	~~1,899.29~~1,480.48

* Cost to be determined on a case-by-case basis.

ISSUED: EFFECTIVE:

ISSUED BY: Robert Sanchez, President
Mahwah, New Jersey 07430

DRAFT

GENERAL INFORMATION
SERVICE CLASSIFICATION RIDER (Continued)

STANDBY SERVICE~~This leaf intentionally left blank.~~

Standby Service will be furnished when and where available to demand billed customers served under Service Classification No. 2 or 7 with on-site generation equipment or other source of electric service under the following conditions:

(a) Customer's on-site generation or other source of electric service equipment meet the requirements of Section 201 and Section 210 of the Public Utilities Regulatory Policies Act and regulations promulgated thereunder for a qualifying facility or the customer's generator meets the definition of distributed generation as defined in N.J.S.A. 48:2-21.37 .

(b) The customer agrees to abide by all provisions of the Company's "Operating, Metering, and Equipment Protection Requirements for Parallel Operation of Generating Facilities."

(c) The customer shall pay for any special metering costs. Special metering costs shall be defined as the total cost of metering less the cost of metering for service under the customer's Service Classification for customers without on-site generation.

(d) The standby capacity for a customer whose total generation capacity (nameplate ratings) is greater than said customer's total demand requirements shall be the amount of standby capacity, in kW, requested by said customer but not less than said customer's maximum demand as metered by the Company in any previous month. The standby capacity for all other customers shall be the nameplate rating, in kW, of all the customer's generation facilities interconnected with the Company's system, as determined by the Company.

(e) The customer shall notify the Company of all changes in customer's generating facilities prior to making such changes and shall allow the Company's representatives access to those facilities for purposes of inspection and redetermination of the standby capacity.

(f) The customer shall pay to the Company a standby capacity charge of $1.55 per kW of standby capacity per month. The standby capacity charge will be included in customer's bill for service rendered under Service Classification No. 2 or No. 7.

(g) In any month where the availability factor of the customer's generation facilities, as defined in (i), is lower than 50%, then the customer will not be eligible to take service under this Rider and the customer will not be charged the standby capacity charge described in (f).

(Continued)

DRAFT

GENERAL INFORMATION
SERVICE CLASSIFICATION RIDER (Continued)

STANDBY SERVICE (Continued)~~This leaf intentionally left blank.~~

(h) In any month where the availability factor of the customer's generation facilities, as defined in (i), is 50% or greater, the customer will pay for all the rates and charges contained in Service Classification No. 2 or No. 7; however, the Distribution Demand Charge shall be calculated based on the billing demand as provided for in the provision in Service Classification No. 2 or No. 7 entitled “DETERMINATION OF DEMAND” minus the customer’s standby capacity. For Service Classification No. 7 customers, this calculation will be performed for each rating period. In no event shall any billing demand be less than zero kW.

(i) For purposes of item (g) above, the availability factor of customer’s facilities shall be defined as the total energy (in kWh) produced by the facilities in the six month period ended with the current billing period (less the energy produced during mutually agreed upon maintenance periods) divided by (i) the number of hours in that period (less the number of hours in the mutually agreed upon maintenance periods) and (ii) the nameplate rating, in kW, of the customer’s generation facilities. During each of the first five billing periods for each customer, the availability factor shall be determined using the data that are available since the customer first commenced service hereunder.

DRAFT

SERVICE CLASSIFICATION NO. 1
RESIDENTIAL SERVICE

APPLICABLE TO USE OF SERVICE FOR

Sales and delivery of electric power supply provided by the Company or delivery of electric power supply provided by an electric generation supplier under the Company's Retail Access Program to residential customers. All service at each residence shall be taken through one meter. Service will also be furnished hereunder to a church and adjacent buildings (other than school buildings which substitute for public education), owned by the church and operated in connection therewith; provided, however, that if the buildings of any such church group are separated by a highway or highways, then the electricity delivered to each group so separated shall not be combined with the electricity delivered to other buildings of the church group but shall be billed separately under this rate.

CHARACTER OF SERVICE

Continuous, 60 cycle, A.C., from any of the following systems as designated by the Company:

(1) Single phase at approximately 120,120/208 or 120/240 volts.

(2) Three phase four wire at approximately 120/208 volts in limited areas.

RATE – MONTHLY

			Summer Months*	Other Months
(1)	Customer Charge		$~~4.53~~6.50	$~~4.53~~6.50
(2)	Distribution Charge			
	First 600 kWh	@	~~4.394~~6.165 ¢ per kWh	~~4.394~~6.165 ¢ per kWh
	Over 600 kWh	@	~~5.537~~7.765 ¢ per kWh	~~4.394~~6.165 ¢ per kWh

* Definition of Summer Billing Months - June through September

(Continued)

ISSUED: EFFECTIVE:

ISSUED BY: Robert Sanchez, President
Mahwah, New Jersey 07430

SERVICE CLASSIFICATION NO. 1
RESIDENTIAL SERVICE (Continued)

RATE – MONTHLY (Continued)

(5) Basic Generation Service

Customers taking Basic Generation Service from the Company will be billed for such service in accordance with General Information Section No. 31.

In accordance with Riders CBT and SUT, the charges in this Rate Schedule include provision for the New Jersey Corporation Business Tax and the New Jersey Sales and Use Tax. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT and SUT, such charges will be reduced by the relevant amount of such taxes included therein.

MINIMUM CHARGE EACH CONTRACT EACH LOCATION

$~~4.53~~6.50 monthly, not less than $~~27.18~~39.00 per contract.

TERMS OF PAYMENT

Bills are due in accordance with General Information Section No. 10.

TERM

Terminable at any time unless a specified period is required under a line extension agreement.

EXTENSION OF FACILITIES

Where service is supplied from an extension the charges thereon shall be determined as provided in General Information.

(Continued)

SERVICE CLASSIFICATION NO. 2
GENERAL SERVICE

APPLICABLE TO USE OF SERVICE FOR

Sales and delivery of electric power supply provided by the Company or delivery of electric power supply provided by an electric generation supplier under the Company's Retail Access Program to general secondary or primary service customers.

A customer taking primary service whose demand exceeds 1,000 kW during any two of the previous twelve months shall not be eligible for this rate and shall be transferred to Service Classification No. 7. A customer so transferred shall only be eligible for transfer back to Service Classification No. 2 on the annual anniversary of the transfer to Service Classification No. 7 and only if said customer has not exceeded 1,000 kW during any two of the previous twelve months.

All service at one location shall be taken through one meter except that service under Special Provision B shall be separately metered.

Demand billed customers with on-site generation or other sources of electric service equipment that meet the requirements of Section 201 and Section 210 of the Public Utilities Regulatory Policies Act and regulations promulgated thereunder for a qualifying facility or customers with generators that meet the definition of distributed generation as defined in N.J.S.A. 48:2-21.37 shall be subject to the provisions of Service Classification Rider – Standby Service.

CHARACTER OF SERVICE

Continuous, 60 cycle, A.C., single or three phase secondary, at approximately 120/208, 120/240 volts, and 277/480 volts where available; or three phase primary at approximately 2400/4160 and 7620/13200 volts Wye, 13000 and 34500 volts Delta, 69000 volts Wye, and in limited areas 2400 or 4800 volts Delta, depending upon the magnitude and characteristics of the load and the circuit from which service is supplied.

RATE – MONTHLY

	Summer Months*	Other Months
(1) Customer Charge		
(a) Secondary Service (Non-Demand Billed)		
Unmetered Service	$~~10.57~~14.00	$~~10.57~~14.00
Metered Service	$~~12.26~~16.00	$~~12.26~~16.00
(b) Secondary Service (Demand Billed)	$~~16.37~~21.01	$~~16.37~~21.01
(c) Primary Service	$~~85.30~~92.00	$~~85.30~~92.00

* Definition of Summer Billing Months - June through September

(Continued)

DRAFT

SERVICE CLASSIFICATION NO. 2
GENERAL SERVICE (Continued)

RATE – MONTHLY (Continued)

			Summer Months*	Other Months
(2) Distribution Charges				
(a) Secondary Service (Non-Demand Billed)				
Usage Charge				
All kWh	........@		~~3.511~~4.328 ¢ per kWh	~~3.182~~3.922 ¢ per kWh
(b) Secondary Service (Demand Billed)				
Demand Charge				
First 5 kW	........@		$~~1.76~~4.53 per kW	$~~1.47~~3.79 per kW
Over 5 kW	........@		$~~3.53~~7.12 per kW	$~~2.99~~6.00 per kW
Usage Charge				
First 4,920 kWh	........@		~~3.427~~3.271 ¢ per kWh	~~3.212~~3.088 ¢ per kWh
Over 4,920 kWh	........@		~~2.874~~2.856 ¢ per kWh	~~2.821~~2.795 ¢ per kWh
(c) Primary Service				
Demand Charge				
All kW	........@		$~~6.90~~7.70 per kW	$~~5.91~~6.60 per kW
Usage Charge				
All kWh	……...@		1.485 ¢ per kWh	1.485 ¢ per kWh

* Definition of Summer Billing Months - June through September

(Continued)

SERVICE CLASSIFICATION NO. 2
GENERAL SERVICE (Continued)

RATE – MONTHLY (Continued)

(5) CIEP Standby Fee

In accordance with General Information Section No. 32, a CIEP Standby Fee shall be assessed on all kWh of customers eligible for BGS-CIEP service.

(6) Basic Generation Service

Customers taking Basic Generation Service from the Company will be billed for such service in accordance with General Information Section No. 31.

In accordance with Riders CBT and SUT, the charges in this Rate Schedule include provision for the New Jersey Corporation Business Tax and the New Jersey Sales and Use Tax. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT and SUT, such charges will be reduced by the relevant amount of such taxes included therein.

MINIMUM MONTHLY CHARGE

Secondary Service (Non-Demand Billed)		
Unmetered Service	$~~10.57~~14.00	
Metered Service	$~~12.26~~16.00	
Secondary Service (Demand Billed)	$~~16.37~~21.01	Plus the demand charge.
Primary Service	$~~85.30~~92.00	Plus the demand charge.

DETERMINATION OF DEMAND

The monthly billing demand in kW shall be either the greatest connected load or the greatest 15-minute integrated demand, determined as follows:

(1) Billing demand may be on a connected load basis when

(a) demand meter would not reduce the billing demand, or

(b) the installation is temporary, or

(c) the device has a large instantaneous or highly fluctuating demand.

(2) Billing shall be on a demand meter basis in all other cases and shall be billed at not less than 90% of the kVA demand. The billing demand for the billing months of October through May inclusive shall not be less than 70% of the highest metered demand for the preceding billing months of June through September inclusive.

(Continued)

DRAFT

SERVICE CLASSIFICATION NO. 2
GENERAL SERVICE (Continued)

SPECIAL PROVISIONS

(A) Short Term Secondary Service

When short term service is requested, the Company reserves the right to require a deposit of the estimated bill for the period service is desired. The minimum charge for such short term service shall be an amount equal to six times the minimum monthly charge, payable in advance. When construction is necessary, the cost of installation and removal of all equipment, less salvage value, shall be borne by the customer, and a sufficient amount to cover these charges shall be paid in advance. A part of a month shall be considered a full month for computing all charges hereunder.

(B) Space Heating

Customers who take service under this classification for 10 kW or more of permanently installed space heating equipment may elect to have the electricity for this service billed separately. All monthly use shall be billed at a Distribution Charge of ~~2.688~~3.779 ¢/kWh during the billing months of October through May and ~~4.478~~6.295 ¢/kWh during the summer billing months. When this option is requested it shall apply for at least 12 months and shall be subject to a minimum charge of $26.87 per year per kW of space heating capacity. This provision applies for both heating and cooling where the two services are combined by the manufacturer in a single self-contained unit.

All usage under this Special Provision shall also be subject to Parts (3), (4), and (6) of RATE – MONTHLY.

This special provision is closed to new customers effective August 1, 2014.

~~(C) Auxiliary Or Standby Service~~

~~Auxiliary or standby service will not be supplied under this service classification.~~

~~Any customer who operates or receives electric service from a qualifying facility and who requires auxiliary or standby service shall be eligible to take such service under Service Classification No. 7 of this Schedule. The term "qualifying facility" shall mean a generating facility that meets the qualifying facility requirements established by the Federal Energy Regulatory Commission's rules (18 CFR Part 292) implementing the Public Utility Regulatory Policies Act of 1978.~~

(Continued)

DRAFT

SERVICE CLASSIFICATION NO. 2
GENERAL SERVICE (Continued)

SPECIAL PROVISIONS (Continued)

~~(C) Auxiliary Or Standby Service (Continued)~~

~~Customers taking service under this Service Classification shall not operate their generating equipment in parallel or synchronism with the Company's service, except as specifically authorized by the Company for the minimum time required by the customer to disconnect auxiliary generating equipment from the regular Company supply following an interruption of the company's service or during an equipment test. A customer having another installed source of energy may, however, segregate any portion of customer's total requirements so that such portion shall be served exclusively with the Company's service.~~

(~~D~~C) Budget Billing Plan

Any condominium association or cooperative housing corporation who takes service hereunder and any other customer taking service under Special Provision B of this Service Classification may, upon request, be billed monthly in accordance with the budget billing plan provided for in General Information Section 8 of this tariff.

(~~E~~D) Veterans' Organization Service

Pursuant to N.J.S.A. 48:2-21.41, when electric service is delivered to a customer that is a Veterans' Organization that is serving the needs of veterans of the armed forces, the customer may apply and be eligible for billing under this Special Provision.

Each customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this Service Classification and by qualifying as a Veterans' Organization as defined by N.J.S.A. 48:2-21.41 as "an organization dedicated to serving the needs of veterans of the armed forces that: is chartered under federal law, qualifies as a tax exempt organization under paragraph (19) of subsection (c) of section 501 of the federal Internal Revenue Code of 1986, 26 U.S.C. s.501 (c)(19), or that is organized as a corporation under the 'New Jersey Nonprofit Corporation Act,' N.J.S.15A:1-1 et seq." Under N.J.S.A. 48: 2-21.41, a qualified Veterans' Organization shall be charged the residential rate for service delivered to the property where the Veterans' Organization primarily operates, if the residential rate is lower than the commercial rate for service at that property.

The customer shall furnish satisfactory proof of eligibility for service under this Special Provision to the Company. Once proof of eligibility is determined by the Company, service under this Special Provision shall begin with the next billing cycle following receipt of the Application.

(Continued)

DRAFT

SERVICE CLASSIFICATION NO. 2
GENERAL SERVICE (Continued)

SPECIAL PROVISIONS (Continued)

(~~E~~D) Veterans' Organization Service (Continued)

The customer will continue to be billed on this Service Classification. At least once annually, the Company shall review eligible customers' distribution charges under this Special Provision for all relevant periods. If the comparable distribution charges under Service Classification No. 1 are lower than the distribution charges under the customer's current Service Classification, a credit in the amount of the difference will be applied to the customer's next bill.

DRAFT

SERVICE CLASSIFICATION NO. 3
RESIDENTIAL TIME-OF-DAY ~~HEATING~~ SERVICE

APPLICABLE TO USE OF SERVICE FOR

Sales and delivery of electric power supply provided by the Company or delivery of electric power supply provided by an electric generation supplier under the Company's Retail Access Program to residential customers, at customer's option~~where an approved electric storage heater is used for customer's entire water heating requirements and/or permanently installed electric space heating equipment is the sole source of space heating, excluding fire places, on the premises. Solar energy collection devices may be used to supplement customer's water and/or space heating requirements~~.

CHARACTER OF SERVICE

Continuous, 60 cycle, A.C., from any of the following systems as designated by the Company:

(1) Single phase at approximately 120,120/208 or 120/240 volts.

(2) Three phase four wire at approximately 120/208 volts in limited areas.

RATE – MONTHLY

			Summer Months*	Other Months
(1)	Customer Charge		\$~~6.50~~9.00	\$~~6.50~~9.00
(2)	Distribution Charge			
	Peak All kWh measured between 10:00 a.m. and 10:00 p.m., Monday through Friday	..........@	~~6.009~~8.463 ¢ per kWh	~~5.391~~7.592 ¢ per kWh
	Off-Peak All other kWh	..........@	~~2.164~~3.048 ¢ per kWh	~~2.164~~3.048 ¢ per kWh

* Definition of Summer Billing Months - June through September

(Continued)

DRAFT

SERVICE CLASSIFICATION NO. 3
RESIDENTIAL TIME-OF-DAY ~~HEATING~~ SERVICE (Continued)

RATE – MONTHLY (Continued)

(3) Transmission Charge

(a) These charges apply to all customers taking Basic Generation Service from the Company. These charges are also applicable to customers located in the Company's Central and Western Divisions and obtaining Competitive Energy Supply. These charges are not applicable to customers located in the Company's Eastern Division and obtaining Competitive Energy Supply. The Company's Eastern, Central and Western Divisions are defined in General Information Section No. 1.

	Summer Months*	Other Months
Peak All kWh measured between 10:00 a.m. and 10:00 p.m., Monday through Friday ......@	1.583 ¢ per kWh	1.583 ¢ per kWh
Off-Peak All other kWh ......@	1.583 ¢ per kWh	1.583 ¢ per kWh

(b) Transmission Surcharge – This charge is applicable to all customers taking Basic Generation Service from the Company and includes surcharges related to Reliability Must Run, EL05-121 Settlement and Transmission Enhancement Charges.

All kWh .....@	1.137 ¢ per kWh	1.137 ¢ per kWh

(4) Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, Securitization Charges, Temporary Tax Act Credit, and Zero Emission Certificate Recovery Charge.

The provisions of the Company's Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, Securitization Charges, Temporary Tax Act Credit, and Zero Emission Certificate Recovery Charge as described in General Information Section Nos. 33, 34, 35, 36, and 37 respectively, shall be assessed on all kWh delivered hereunder.

* Definition of Summer Billing Months - June through September

(Continued)

DRAFT

SERVICE CLASSIFICATION NO. 3
RESIDENTIAL TIME-OF-DAY ~~HEATING~~ SERVICE (Continued)

RATE – MONTHLY (Continued)

(5) Basic Generation Service

Customers taking Basic Generation Service from the Company will be billed for such service in accordance with General Information Section No. 31.

In accordance with Riders CBT and SUT, the charges in this Rate Schedule include provision for the New Jersey Corporation Business Tax and the New Jersey Sales and Use Tax. When billed to customers exempt from one or more of these taxes, as set forth in Riders CBT and SUT, such charges will be reduced by the relevant amount of such taxes included therein.

MINIMUM CHARGE EACH CONTRACT EACH LOCATION

The Customer Charge, not less than $~~78.00~~108.00 per contract.

TERMS OF PAYMENT

Bills are due in accordance with General Information Section No. 10.

TERM

The initial term of service shall be one year. Customers opting for this rate shall not be entitled to service at the same location under the Company's Service Classification Nos. 1 or 5 until one year from the date of service or thereafter on the annual anniversary date upon 5 days' prior written notice.

EXTENSION OF FACILITIES

Where service is supplied from an extension the charges thereon shall be determined as provided in General Information.

(Continued)

DRAFT

SERVICE CLASSIFICATION NO. 3
RESIDENTIAL TIME-OF-DAY ~~HEATING~~ SERVICE (Continued)

SPECIAL PROVISIONS

(A) Metering

The customer shall guarantee the Company access to the meter at all times. In the event the Company is unable to obtain the necessary meter readings, it shall estimate the consumption based on all the data available and apply the rates as specified in RATE – MONTHLY.

~~(B) Approved Water Heater~~

~~An approved electric water heater is one that has a minimum storage capacity of 40 gallons and two heating elements with the upper and lower elements so interlocked that they may not operate simultaneously. The size of the elements shall not exceed those listed in the tabulation below:~~

~~Gallons~~	~~40~~	~~50~~	~~66~~	~~82~~	~~110~~
~~Upper element, Maximum Watts~~	~~4500~~	~~1500~~	~~2500~~	~~3000~~	~~4000~~
~~Lower element, Maximum Watts~~	~~4500~~	~~1000~~	~~1500~~	~~1500~~	~~2500~~

~~The 40 gallons heater is restricted to use in mobile homes and individual apartments.~~

(~~C~~B) Budget Billing

Not available under this Service Classification.

DRAFT

SERVICE CLASSIFICATION NO. 4
PUBLIC STREET LIGHTING SERVICE (Continued)

RATE – MONTHLY

(1) Distribution and Transmission Charges

(a) Distribution Luminaire Charges

Nominal Lumens	Luminaire Type	Watts	Total Wattage	Distribution Charge
Street Lighting Luminaires				
5,800	Sodium Vapor	70	108	$~~7.60~~9.47
9,500	Sodium Vapor	100	142	~~8.25~~10.28
16,000	Sodium Vapor	150	199	~~10.04~~12.51
27,500	Sodium Vapor	250	311	~~12.82~~15.96
46,000	Sodium Vapor	400	488	~~20.79~~25.89
~~3,400~~	~~Induction~~	~~40~~	~~45~~	~~7.95~~
~~5,950~~	~~Induction~~	~~70~~	~~75~~	~~8.10~~
~~8,500~~	~~Induction~~	~~100~~	~~110~~	~~9.15~~
~~12,750~~	~~Induction~~	~~150~~	~~160~~	~~11.43~~
~~21,250~~	~~Induction~~	~~250~~	~~263~~	~~14.85~~
3,000	LED	20-25	23	8.21
3,900	LED	30-39	35	8.05
5,000	LED	40-59	50	8.07
~~5,890~~	~~LED~~	~~70~~	~~74~~	~~8.71~~
7,250	LED	60-79	68	8.41
~~9,365~~	~~LED~~	~~100~~	~~101~~	~~10.68~~
12,000	LED	95-110	103	9.46
16,000	LED	130-150	140	9.92
22,000	LED	180-220	200	14.53
Flood Lighting Luminaires				
15,500	LED	115-130	125	$11.43
27,000	LED	175-225	205	14.58
37,500	LED	265-315	290	15.88

The following luminaires will no longer be installed. Charges are for existing luminaires only.

Nominal Lumens	Luminaire Type	Watts	Total Wattage	Distribution Charge
Street Lighting Luminaires				
1,000	Open Bottom Incandescent	92	92	$~~5.03~~6.27
~~2,500~~	~~Open Bottom Incandescent~~	~~189~~	~~189~~	~~6.73~~

~~6,000~~	~~Closed Bottom Incandescent~~	~~405~~	~~405~~		~~10.33~~
4,000	Mercury Vapor	100	127	~~6.81~~8.49	
7,900	Mercury Vapor	175	211	~~8.03~~10.00	
12,000	Mercury Vapor	250	296	~~10.44~~13.00	
22,500	Mercury Vapor	400	459	~~13.25~~16.51	
40,000	Mercury Vapor	700	786	~~20.15~~25.10	
59,000	Mercury Vapor	1,000	1,105	~~25.47~~31.72	

(Continued)

SERVICE CLASSIFICATION NO. 4
PUBLIC STREET LIGHTING SERVICE (Continued)

RATE – MONTHLY (Continued)

(1) Distribution and Transmission Charges (Continued)

(a) Distribution Luminaire Charges (Continued)

Nominal Lumens	Luminaire Type	Watts	Total Wattage	Distribution Charge
Street Lighting Luminaires (Continued)				
3,400	Induction	40	45	$9.91
5,950	Induction	70	75	10.09
8,500	Induction	100	110	11.39
5,890	LED	70	74	10.84
9,365	LED	100	101	13.32
~~Off-Roadway Luminaires~~				
~~27,500~~	~~Sodium Vapor~~	~~250~~	~~311~~	~~$ 16.94~~
~~46,000~~	~~Sodium Vapor~~	~~400~~	~~488~~	~~23.82~~
Post-Top Luminaires				
4,000	Mercury Vapor	100	130	$~~10.36~~12.90
7,900	Mercury Vapor	175	215	~~12.70~~15.81
7,900	Merc. Vapor-Offset	175	215	~~14.92~~18.57
16,000	Sod.~~ium~~ Vapor-Offset	150	199	~~20.29~~25.27

(b) Transmission Charges

A Transmission Charge of 1.280 ¢ per kWh will apply to all customers taking Basic Generation Service from the Company. Transmission charges are also applicable to customers located in the Company's Central and Western Divisions and obtaining Competitive Energy Supply. Transmission charges are not applicable to customers located in the Company's Eastern Division and obtaining Competitive Energy Supply. The Company's Eastern, Central and Western Divisions are defined in General Information Section No. 1. A Transmission Surcharge, to recover Reliability Must Run Charges, of 0.001 ¢ per kWh will also apply to all customers taking Basic Generation Service from the Company.

Transmission Charges shall be applied to the kWh estimate in the following manner:

kWh = (Total Wattage divided by 1,000) times Monthly Burn Hours*

*See Monthly Burn Hours Table

(Continued)

SERVICE CLASSIFICATION NO. 4
PUBLIC STREET LIGHTING SERVICE (Continued)

RATE – MONTHLY (Continued)

(2) Additional Charge

(a) An additional $~~17.35~~21.60 per luminaire per month will be charged for existing Underground Service where the Company owns and maintains the entire facilities.

(b) An additional $~~4.22~~5.26 per luminaire per month will be charged for existing underground service where the customer has installed, owns and maintains the duct system complete, but not the aluminum standard or luminaire.

(c) An additional $0.~~47~~ 59 per bracket per month will be charged for a fifteen foot bracket when installed.

(3) Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, Securitization Charges, Temporary Tax Act Credit, and Zero Emission Certificate Recovery Charge.

The provisions of the Company's Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, Securitization Charges, Temporary Tax Act Credit, and Zero Emission Certificate Recovery Charge as described in General Information Section Nos. 33, 34, 35, 36, and 37 respectively shall be assessed on all kWh delivered hereunder.

The charges shall be applied to the kWh estimate in the following manner:

kWh = (Total Wattage divided by 1,000) times Monthly Burn Hours*

* See Monthly Burn Hours Table.

(Continued)

DRAFT

SERVICE CLASSIFICATION NO. 5
RESIDENTIAL SPACE HEATING SERVICE

APPLICABLE TO USE OF SERVICE FOR

Sales and delivery of electric power supply provided by the Company or delivery of electric power supply provided by an electric generation supplier under the Company's Retail Access Program to residential customers, where electricity is a source of space heating subject to the conditions specified in "Special Provisions". All service at each residence shall be taken through one meter.

CHARACTER OF SERVICE

Continuous, 60 cycle, A.C., from any of the following systems as designated by the Company:

(1) Single phase at approximately 120,120/208 or 120/240 volts.

(2) Three phase four wire at approximately 120/208 volts in limited areas.

RATE – MONTHLY

			Summer Months*	Other Months
(1)	Customer Charge		$~~4.53~~6.50	$~~4.53~~6.50
(2)	Distribution Charge			
	First 600 kWh	..........@	~~4.460~~6.165 ¢ per kWh	~~4.460~~6.165 ¢ per kWh
	Over 600 kWh	..........@	~~5.420~~7.765 ¢ per kWh	~~4.460~~6.165 ¢ per kWh

*Definition of Summer Billing Months - June through September

(Continued)

SERVICE CLASSIFICATION NO. 5
RESIDENTIAL SPACE HEATING SERVICE (Continued)

RATE – MONTHLY (Continued)

(5) Basic Generation Service

Customers taking Basic Generation Service from the Company will be billed for such service in accordance with General Information Section No. 31.

In accordance with Riders CBT and SUT, the charges in this Rate Schedule include provision for the New Jersey Corporation Business Tax and the New Jersey Sales and Use Tax. When billed to customers exempt from one or more customers exempt from one or more of these taxes, as set forth in Riders CBT and SUT, such charges will be reduced by the relevant amount of such taxes included therein.

MINIMUM CHARGE EACH CONTRACT EACH LOCATION

$~~4.53~~6.50 monthly, not less than $~~27.18~~39.00 per contract.

TERMS OF PAYMENT

Bills are due in accordance with General Information Section No. 10.

TERM

Terminable at any time unless a specified period is required under a line extension agreement.

EXTENSION OF FACILITIES

Where service is supplied from an extension the charges thereon shall be determined as provided in General Information.

(Continued)

DRAFT

SERVICE CLASSIFICATION NO. 6
PRIVATE OVERHEAD LIGHTING SERVICE (Continued)

RATE – MONTHLY:

(1) Distribution and Transmission Charges

(a) Luminaire Charges for Service Types A and B

Nominal Lumens	Luminaire Type	Watts	Total Wattage	Distribution Charge
Power Bracket Luminaires				
5,800	Sodium Vapor	70	108	$~~5.34~~7.51
9,500	Sodium Vapor	100	142	~~6.42~~9.02
16,000	Sodium Vapor	150	199	~~6.89~~9.68
3,950	LED	30-44	35	7.57
5,550	LED	45-49	50	7.68
7,350	LED	60-70	65	7.75
Street Lighting Luminaires				
5,800	Sodium Vapor	70	108	$~~7.43~~10.45
9,500	Sodium Vapor	100	142	~~8.16~~11.46
16,000	Sodium Vapor	150	199	~~10.02~~14.09
27,500	Sodium Vapor	250	311	~~12.86~~18.07
46,000	Sodium Vapor	400	488	~~21.22~~29.83
3,000	LED	20-25	23	8.21
3,900	LED	30-39	35	8.05
5,000	LED	40-59	50	8.07
7,250	LED	60-79	68	8.41
12,000	LED	95-110	103	9.46
~~3,400~~	~~Induction~~	~~40~~	~~45~~	~~8.00~~
~~5,950~~	~~Induction~~	~~70~~	~~75~~	~~8.17~~
~~8,500~~	~~Induction~~	~~100~~	~~110~~	~~9.20~~
~~12,750~~	~~Induction~~	~~150~~	~~160~~	~~11.50~~
~~21,250~~	~~Induction~~	~~250~~	~~263~~	~~14.96~~
16,000	LED	130-150	140	9.92
~~5,890~~	~~LED~~	~~70~~	~~74~~	~~8.75~~
~~9,365~~	~~LED~~	~~100~~	~~101~~	~~10.77~~
22,000	LED	180-220	200	14.53
Flood lighting Luminaires				
~~27,500~~	~~Sodium Vapor~~	~~250~~	~~311~~	~~$ 12.86$ 29.83~~
46,000	Sodium Vapor	400	488	~~21.22~~
15,500	LED	115-130	125	11.43

ISSUED: EFFECTIVE:

ISSUED BY: Robert Sanchez, President
Mahwah, New Jersey 07430

27,000	LED	175-225	205	14.58
37,500	LED	265-315	290	15.88

(Continued)

DRAFT

SERVICE CLASSIFICATION NO. 6
PRIVATE OVERHEAD LIGHTING SERVICE (Continued)

RATE – MONTHLY (Continued)

(1) Distribution and Transmission Charges (Continued)

(a) Luminaire Charges for Service Types A and B (Continued)

Nominal Lumens	Luminaire Type	Watts	Total Wattage	Distribution Charge

The following luminaires will no longer be installed. Charges are for existing luminaires only.

Power Bracket Luminaires

4,000	Mercury Vapor	100	127	$~~8.30~~11.66
7,900	Mercury Vapor	175	215	~~9.59~~13.48
22,500	Mercury Vapor	400	462	~~15.28~~21.48

Post Top Luminaires

16,000	~~Sodium~~ Sod. Vapor-Offset	150	199	$~~19.73~~27.73

Street Lighting Luminaires

4,000	Mercury Vapor	100	127	$ ~~9.12~~12.82
7,900	Mercury Vapor	175	211	~~10.42~~14.64
22,500	Mercury Vapor	400	459	~~16.19~~22.75
1,000	Incandescent	-	92	~~7.41~~10.42
~~2,500~~	~~Incandescent~~	~~-~~	~~189~~	~~9.56~~
3,400	Induction	40	45	11.24
5,950	Induction	70	75	11.48
8,500	Induction	100	110	12.93
5,890	LED	70	74	12.30
9,365	LED	100	101	15.14

Flood lighting Luminaires

12,000	Mercury Vapor	250	296	$~~13.10~~18.42
40,000	Mercury Vapor	700	786	~~23.72~~33.35
59,000	Mercury Vapor	1,000	1,105	~~29.55~~41.53

(Continued)

DRAFT

SERVICE CLASSIFICATION NO. 6
PRIVATE OVERHEAD LIGHTING SERVICE (Continued)

RATE – MONTHLY (Continued)

(1) Distribution and Transmission Charges (Continued)

(b) Distribution Charges for Service Type C

Metered Service - Customer Charge at $~~11.53~~14.00 per month plus Distribution Charge at ~~4.992~~6.251 ¢ per kWh; or

Unmetered Service - Customer Charge at $~~2.40~~3.00 per month plus Distribution Charge at ~~4.992~~6.251 ¢ per kWh.

(c) Transmission Charges for Service Types A, B, and C

A Transmission Charge of 1.280 ¢ per kWh will apply to all customers taking Basic Generation Service from the Company. Transmission charges are also applicable to customers located in the Company's Central and Western Divisions and obtaining Competitive Energy Supply. Transmission charges are not applicable to customers located in the Company's Eastern Division and obtaining Competitive Energy Supply. The Company's Eastern, Central and Western Divisions are defined in General Information Section No. 1. A Transmission Surcharge, to recover Reliability Must Run Charges, of 0.001 ¢ per kWh will also apply to all customers taking Basic Generation Service from the Company.

For service type A, B, or C if not metered, the charges shall be applied to the kWh estimated as follows:

kWh = (Total Wattage divided by 1,000) times Monthly Burn Hours*

(2) Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, Securitization Charges, Temporary Tax Act Credit, and Zero Emission Certificate Recovery Charge.

The provisions of the Company's Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, Securitization Charges, Temporary Tax Act Credit, and Zero Emission Certificate Recovery Charge as described in General Information Section Nos. 33, 34, 35, 36, and 37 respectively shall be assessed on all kWh delivered hereunder. For service type A, B, or C if not metered, the charges shall be applied to the kWh estimated as follows:

kWh = (Total Wattage divided by 1,000) times Monthly Burn Hours*

* See Monthly Burn Hours Table.

(Continued)

DRAFT

SERVICE CLASSIFICATION NO. 6
PRIVATE OVERHEAD LIGHTING SERVICE (Continued)

MINIMUM CHARGE

The minimum charge per luminaire for Service Type A or B shall be the sum of the monthly Distribution and Transmission Charges as specified in RATE – MONTHLY, Part (1a) times twelve. Should the monthly charge be revised during the initial term, the minimum charge per installation shall be prorated accordingly.

The minimum charge for Service Type C - Metered shall be $~~11.53~~14.00 per month and not less than $~~138.36~~168.00 for the initial term.

The minimum charge for Service Type C - Unmetered shall be $~~2.40~~3.00 per month and not less than $~~28.80~~36.00 for the initial term.

TERM

The Initial Term shall be one year. Service shall continue in effect thereafter until canceled by either party upon thirty days written notice. The Company shall require an Initial Term of one year for each luminaire for Service Types A or B.

TERMS OF PAYMENT

Bills are due in accordance with General Information Section No. 10.

(Continued)

DRAFT

SERVICE CLASSIFICATION NO. 6
PRIVATE OVERHEAD LIGHTING SERVICE (Continued)

SPECIAL PROVISIONS

Special Provisions A, B, D, E, F, and J apply only to Service Types A and B. Special Provision K applies only to Service Type C. Special Provisions C, G, H, and I apply to Service Types A, B, and C.

(A) Street lighting luminaires will normally be mounted on eight foot aluminum brackets. Fifteen foot brackets are available at an additional charge of $0.~~52~~ 74 per bracket per month.

(B) Luminaires will be installed free of charge where all facilities necessary to serve a luminaire are present. Customer shall pay the cost of any additional facilities required, prior to the commencement of the construction of such facilities.

(C) The customer shall furnish the Company with all easements or rights-of-way necessary to provide service to the desired location before any installation or construction will be started.

(D) A customer may apply for service hereunder for a proposed residential subdivision in which all electric facilities will be underground. Such application shall be signed by the customer and builder or developer and when accepted by the Company, shall constitute an agreement between the Company, customer and builder or developer subject to the terms and provisions hereunder.

The builder or developer shall pay to the Company prior to the commencement of any construction all costs associated with the installation of the facilities to be serviced hereunder and shall prepay six times the total monthly charge for all luminaires installed. Said monthly charges shall be determined using the rates in effect at the time said costs and charges are determined. The Company shall not bill the customer for the first six months of service of the facilities installed under this special provision.

(E) The Company shall not be obligated to repair or replace in kind any obsolete luminaire for which it cannot reasonably obtain the necessary parts. The Company will remove the obsolete luminaire or at the customer's request, replace it with any luminaire offered for service at that time for which the customer will be charged the appropriate rates.

(Continued)

DRAFT

SERVICE CLASSIFICATION NO. 7
LARGE GENERAL TIME-OF-DAY SERVICE

APPLICABLE TO USE OF SERVICE FOR

Sales and delivery of electric power supply provided by the Company or delivery of electric power supply provided by an electric generation supplier under the Company's Retail Access Program to primary service customers who maintain a minimum demand of 1,000 kW during any two of the previous twelve months and provide all equipment required to take service at a primary voltage as designated by the Company. A primary customer who does not maintain a demand of at least 1,000 kW during any two of the previous twelve months, may, at the customer's option transfer to another Service Classification provided that such transfer shall only be made on an annual anniversary date that such customer began service hereunder.

Sales and delivery of electric power supply provided by the Company or delivery of electric power supply provided by an electric generation supplier under the Company's Retail Access Program to high voltage distribution service customers with a minimum demand of 1,000 kW who provide all equipment required to take high voltage distribution service as designated by the Company. High voltage distribution service shall be made available at the sole discretion of the Company where conditions merit.

Customers with on-site generation or other sources of electric service equipment that meet the requirements of Section 201 and Section 210 of the Public Utilities Regulatory Policies Act and regulations promulgated thereunder for a qualifying facility or customers with generators that meet the definition of distributed generation as defined in N.J.S.A. 48:2-21.37 shall be subject to the provisions of Service Classification Rider – Standby Service.
~~Any customer who operates a qualifying facility, as defined below, and who requires supplemental, auxiliary or standby service to be supplied by the Company. The term "qualifying facility" shall mean a generating facility that meets the qualifying facility requirements established by the Federal Energy Regulatory Commission's rules (18 CFR Part 292) implementing the Public Utility Regulatory Policies Act of 1978.~~

All service at one location shall be taken through one meter except that service taken under Special Provision A shall be separately metered.

CHARACTER OF SERVICE

Continuous, 60 cycles, A.C., single or three phase primary or high voltage distribution service as defined in General Information Section 26 and depending on the magnitude and characteristics of the load and the circuit from which service is supplied.

RATE – MONTHLY

	Primary	High Voltage Distribution
(1) Customer Charge	$~~212.35~~250.00	$2,288.12

DRAFT

SERVICE CLASSIFICATION NO. 7
LARGE GENERAL TIME-OF-DAY SERVICE (Continued)

RATE – MONTHLY (Continued)

(2) Distribution Charges

		Primary	High Voltage Distribution
Demand Charge			
Period I	All kW @	$~~2.94~~3.88 per kW	$~~0.92~~ 1.10 per kW
Period II	All kW @	~~0.73~~0.96 per kW	~~0.21~~0.26 per kW
Period III	All kW @	~~2.70~~3.56 per kW	~~0.84~~1.01 per kW
Period IV	All kW @	~~0.73~~0.96 per kW	~~0.21~~0.26 per kW
Usage Charge			
Period I	All kWh @	1.770 ¢ per kWh	0.203 ¢ per kWh
Period II	All kWh @	1.325 ¢ per kWh	0.151 ¢ per kWh
Period III	All kWh @	1.770 ¢ per kWh	0.203 ¢ per kWh
Period IV	All kWh @	1.325 ¢ per kWh	0.151 ¢ per kWh

(3) Transmission Charges

(a) These charges apply to all customers taking Basic Generation Service from the Company. These charges are also applicable to customers located in the Company's Central and Western Divisions and obtaining Competitive Energy Supply. These charges are not applicable to customers located in the Company's Eastern Division and obtaining Competitive Energy Supply. The Company's Eastern, Central and Western Divisions are defined in General Information Section No. 1.

(Continued)

DRAFT

SERVICE CLASSIFICATION NO. 7
LARGE GENERAL TIME-OF-DAY SERVICE (Continued)

SPECIAL PROVISIONS

(A) Space Heating

Customers who take service under this classification for 10 kW or more of permanently installed space heating equipment may elect to have the electricity for this service billed separately. All monthly use shall be billed at a Distribution Charge of ~~2.902~~4.081 ¢ per kWh during the billing months of October through May and ~~4.693~~6.597 ¢ per kWh during the summer billing months, a Transmission Charge of 0.421 ¢ per kWh and a Transmission Surcharge of 0.656 ¢ per kWh during all billing months. The applicability of Transmission Charges and the Transmission Surcharge is described in Part (3) of RATE – MONTHLY.

When this option is requested it shall apply for at least 12 months and shall be subject to a minimum charge of $26.87 per year per kW of space heating capacity. This provision applies for both heating and cooling where the two services are combined by the manufacturer in a single self-contained unit.

All usage under this Special Provision shall also be subject to Parts (4), (5), and (6) of RATE – MONTHLY. This Special Provision is not available to those customers taking high voltage distribution service.

This special provision is closed to new customers effective August 1, 2014.

(B) Budget Billing Plan

Any condominium association or cooperative housing corporation who takes service hereunder and any other customer taking service under Special Provision B of this Service Classification may, upon request, be billed monthly in accordance with the budget billing plan provided for in General Information Section 8 of this tariff.

(Continued)

DRAFT

SERVICE CLASSIFICATION NO. 7
LARGE GENERAL TIME-OF-DAY SERVICE (Continued)

This leaf intentionally left blank.~~**SPECIAL PROVISIONS (Continued)**~~

~~(C) Standby Service~~

~~Standby Service will be furnished when and where available to customers with on-site generation equipment or other source of electric service under the following conditions:~~

~~(a) Customer's on-site generation or other source of electric service equipment meets the requirements of Section 201 and Section 210 of the Public Utilities Regulatory Policies Act and regulations promulgated thereunder for a qualifying facility.~~

~~(b) The customer agrees to abide by all provisions of the Company's "Operating, Metering, and Equipment Protection Requirements for Parallel Operation of Generating Facilities."~~

~~(c) The customer shall pay for any special metering costs. Special metering costs shall be defined as the total cost of metering less the cost of metering for service under this Service Classification for customers without on-site generation.~~

~~(d) The standby capacity for a customer whose total generation capacity (nameplate ratings) is greater than said customer's total demand requirements shall be the amount of standby capacity, in kW, requested by said customer but not less than said customer's maximum demand as metered by the Company in any previous month. The standby capacity for all other customers shall be the nameplate rating, in kW, of all the customer's generation facilities interconnected with the Company's system, as determined by the Company.~~

~~(e) The customer shall notify the Company of all changes in customer's generating facilities prior to making such changes and shall allow the Company's representatives access to those facilities for purposes of inspection and redetermination of the standby capacity.~~

~~(f) Customer shall pay to the Company a standby capacity charge of $1.55 per kW of standby capacity per month. The standby capacity charge will be included in customer's bill for service rendered under this Service Classification.~~

~~(Continued)~~

DRAFT

SERVICE CLASSIFICATION NO. 7
LARGE GENERAL TIME-OF-DAY SERVICE (Continued)

This leaf intentionally left blank.~~**SPECIAL PROVISIONS (Continued)**~~

~~(C) Standby Service (Continued)~~

~~(g) The billing demand for each rating period shall be determined as follows:~~

~~(1) In any billing period where the availability factor of customer's facilities is less than 50 percent, the billing demand shall be as provided for in the provision entitled "DETERMINATION OF DEMAND" and the customer shall be excused from paying the standby capacity charge;~~

~~(2) In any billing period where the availability factor of customer's facilities is 50 percent or greater, the billing demand shall be the billing demand as provided for in the provision entitled "DETERMINATION OF DEMAND" minus the customer's standby capacity;~~

~~(3) In any billing period where the availability factor of customer's facilities is greater than 90 percent, the billing demand shall be the billing demand as provided for in the provision entitled "DETERMINATION OF DEMAND" minus the customer's standby capacity and customer shall be excused from paying the standby capacity charge; and~~

~~(4) In no event shall the billing demand for any rating period be less than zero kW.~~

~~(h) For purposes of item g above, the availability factor of customer's facilities shall be defined as the total energy (in kWh) produced by the facilities in the six month period ended with the current billing period (less the energy produced during mutually agreed upon maintenance periods) divided by (i) the number of hours in that period (less the number of hours in the mutually agreed upon maintenance periods) and (ii) the customer's standby capacity. The availability factor shall be so determined for each rating period as defined above in the provision entitled "DEFINITION OF RATING PERIODS". Rating periods 1 and 3 and rating periods 2 and 4 shall be considered as the same rating periods for purposes of determining the availability factor. During each of the first five billing periods for each customer, the availability factor shall be determined using the data that are available since the customer first commenced service hereunder.~~

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 1

		Present		Proposed	
		Summer	Winter	Summer	Winter
Customer Charge:	per month	$4.53	$4.53	$6.50	$6.50
Distribution Charge:					
First 600 kWh	¢ per kWh	4.394	4.394	6.165	6.165
Over 600 kWh	¢ per kWh	5.537	4.394	7.765	6.165
Transmission Charge (incl Trans Surch):					
All kWh	¢ per kWh	3.345	3.345	3.345	3.345
RGGI Surcharge	¢ per kWh	0.0921	0.0921	0.0921	0.0921
Societal Benefits Charge	¢ per kWh	0.6050	0.6050	0.6050	0.6050
Securitization Charges:					
TBC	¢ per kWh	0.276	0.276	0.276	0.276
TBC-Tax	¢ per kWh	0.052	0.052	0.052	0.052
Total	¢ per kWh	0.328	0.328	0.328	0.328
Temporary Tax Act Credit	¢ per kWh	(0.235)	(0.235)	(0.235)	(0.235)
ZEC Recovery Charge	¢ per kWh	0.400	0.400	0.400	0.400
Basic Generation Service:					
First 600 kWh	¢ per kWh	6.474	8.382	6.474	8.382
Over 600 kWh	¢ per kWh	9.835	8.382	9.835	8.382
Reconciliation Charge	¢ per kWh	Variable	Variable	Variable	Variable
Minimum Charge:					
Monthly	monthly	$4.53		$6.50	
Per Contract	per contract	$27.18		$39.00	

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 2
Secondary Demand Billed

		Present		Proposed	
		Summer	Winter	Summer	Winter
Customer Charge:	per month	$16.37	$16.37	$21.01	$21.01
Distribution Charge:					
Demand Charge					
First 5 kW	per kW	$1.76	$1.47	$4.53	$3.79
Over 5 kW	per kW	3.53	2.99	7.12	6.00
Usage Charge					
First 4,920 kWh	¢ per kWh	3.427	3.212	3.271	3.088
Over 4,920 kWh	¢ per kWh	2.874	2.821	2.856	2.795
Transmission Charge (incl Trans Surch):					
Demand Charge					
All kW	per kW	$1.41	$1.18	$1.41	$1.18
Usage Charge					
All kWh	¢ per kWh	1.105	1.105	1.105	1.105
RGGI Surcharge	¢ per kWh	0.0921	0.0921	0.0921	0.0921
Societal Benefits Charge	¢ per kWh	0.6050	0.6050	0.6050	0.6050
Securitization Charges:					
TBC	¢ per kWh	0.276	0.276	0.276	0.276
TBC-Tax	¢ per kWh	0.052	0.052	0.052	0.052
Total	¢ per kWh	0.328	0.328	0.328	0.328
Temporary Tax Act Credit	¢ per kWh	(0.2350)	(0.2350)	(0.2350)	(0.2350)
ZEC Recovery Charge	¢ per kWh	0.4000	0.4000	0.4000	0.4000

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 2
Secondary Demand Billed (Continued)

Basic Generation Service: (Non-CIEP Billed)		Present Summer	Present Winter	Proposed Summer	Proposed Winter
Demand Charge					
First 5 kW	per kW	$1.81	$1.48	$1.81	$1.48
Over 5 kW	per kW	6.27	5.23	6.27	5.23
Usage Charge					
All kWh	¢ per kWh	5.651	5.210	5.651	5.210
Reconciliation Charge	¢ per kWh	Variable	Variable	Variable	Variable
Minimum Charge:		$16.37	plus the demand charge	$21.01	plus the demand charge

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 2
Secondary Non-Demand Billed - Metered

		Present		Proposed	
		Summer	Winter	Summer	Winter
Customer Charge:	per month	$12.26	$12.26	$16.00	$16.00
Distribution Charge:					
Usage Charge					
All kWh	¢ per kWh	3.511	3.182	4.328	3.922
Transmission Charge (incl Trans Surch):					
Usage Charge					
All kWh	¢ per kWh	1.105	1.105	1.105	1.105
RGGI Surcharge	¢ per kWh	0.0921	0.0921	0.0921	0.0921
Societal Benefits Charge	¢ per kWh	0.6050	0.6050	0.6050	0.6050
Securitization Charges:					
TBC	¢ per kWh	0.276	0.276	0.276	0.276
TBC-Tax	¢ per kWh	0.052	0.052	0.052	0.052
Total	¢ per kWh	0.328	0.328	0.328	0.328
Temporary Tax Act Credit	¢ per kWh	(0.2350)	(0.2350)	(0.2350)	(0.2350)
ZEC Recovery Charge	¢ per kWh	0.4000	0.4000	0.4000	0.4000
Basic Generation Service:					
Usage Charge					
All kWh	¢ per kWh	7.358	6.425	7.358	6.425
Reconciliation Charge	¢ per kWh	Variable	Variable	Variable	Variable
Minimum Charge:		$12.26		$16.00	

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 2
Secondary Non-Demand Billed - Unmetered

		Present		Proposed	
		Summer	Winter	Summer	Winter
Customer Charge:	per month	$10.57	$10.57	$14.00	$14.00
Distribution Charge:					
Usage Charge					
All kWh	¢ per kWh	3.511	3.182	4.328	3.922
Transmission Charge (incl Trans Surch):					
Usage Charge					
All kWh	¢ per kWh	1.105	1.105	1.105	1.105
RGGI Surcharge	¢ per kWh	0.0921	0.0921	0.0921	0.0921
Societal Benefits Charge	¢ per kWh	0.6050	0.6050	0.6050	0.6050
Securitization Charges:					
TBC	¢ per kWh	0.276	0.276	0.276	0.276
TBC-Tax	¢ per kWh	0.052	0.052	0.052	0.052
Total	¢ per kWh	0.328	0.328	0.328	0.328
Temporary Tax Act Credit	¢ per kWh	(0.2350)	(0.2350)	(0.2350)	(0.2350)
ZEC Recovery Charge	¢ per kWh	0.4000	0.4000	0.4000	0.4000
Basic Generation Service:					
Usage Charge					
All kWh	¢ per kWh	7.358	6.425	7.358	6.425
Reconciliation Charge	¢ per kWh	Variable	Variable	Variable	Variable
Minimum Charge:		$10.57		$14.00	

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 2
Space Heating

		Present		Proposed	
		Summer	Winter	Summer	Winter
Distribution Charge:					
Usage Charge					
All kWh	¢ per kWh	4.478	2.688	6.295	3.779
Transmission Charge (incl Trans Surch):					
All kWh	¢ per kWh	1.105	1.105	1.105	1.105
RGGI Surcharge	¢ per kWh	0.0921	0.0921	0.0921	0.0921
Societal Benefits Charge	¢ per kWh	0.6050	0.6050	0.6050	0.6050
Securitization Charges:					
TBC	¢ per kWh	0.276	0.276	0.276	0.276
TBC-Tax	¢ per kWh	0.052	0.052	0.052	0.052
Total	¢ per kWh	0.328	0.328	0.328	0.328
Temporary Tax Act Credit	¢ per kWh	(0.2350)	(0.2350)	(0.2350)	(0.2350)
ZEC Recovery Charge	¢ per kWh	0.4000	0.4000	0.4000	0.4000
Basic Generation Service:					
Usage Charge					
All kWh	¢ per kWh	7.358	6.425	7.358	6.425
Reconciliation Charge	¢ per kWh	Variable	Variable	Variable	Variable

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 2
Primary

		Present		Proposed	
		Summer	Winter	Summer	Winter
Customer Charge:	per month	$85.30	$85.30	$92.00	$92.00
Distribution Charge:					
Demand Charge					
All kW	per kW	$6.90	$5.91	$7.70	$6.60
Usage Charge					
All kWh	¢ per kWh	1.485	1.485	1.485	1.485
Transmission Charge (incl Trans Surch):					
Demand Charge					
All kW	per kW	$1.41	$1.27	$1.41	$1.27
Usage Charge					
All kWh	¢ per kWh	1.105	1.105	1.105	1.105
RGGI Surcharge	¢ per kWh	0.0921	0.0921	0.0921	0.0921
Societal Benefits Charge	¢ per kWh	0.6050	0.6050	0.6050	0.6050
Securitization Charges:					
TBC	¢ per kWh	0.276	0.276	0.276	0.276
TBC-Tax	¢ per kWh	0.052	0.052	0.052	0.052
Total	¢ per kWh	0.328	0.328	0.328	0.328
Temporary Tax Act Credit	¢ per kWh	(0.2350)	(0.2350)	(0.2350)	(0.2350)
ZEC Recovery Charge	¢ per kWh	0.4000	0.4000	0.4000	0.4000

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 2
Primary (Continued)

Basic Generation Service: (Non-CIEP Billed)		Present Summer	Present Winter	Proposed Summer	Proposed Winter
Demand Charge					
First 5 kW	per kW	$1.81	$1.48	$1.81	$1.48
Over 5 kW	per kW	6.27	5.23	6.27	5.23
Usage Charge					
All kWh	¢ per kWh	5.651	5.210	5.651	5.210
Reconciliation Charge	¢ per kWh	Variable	Variable	Variable	Variable
Minimum Charge:		$85.30	plus the demand charge	$92.00	plus the demand charge

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 3

		Present		Proposed	
		Summer	Winter	Summer	Winter
Customer Charge:	per month	$6.50	$6.50	$9.00	$9.00
Distribution Charge:					
All kWh, Monday to Friday, 10 A.M. to 10 P.M.	¢ per kWh	6.009	5.391	8.463	7.592
All Other kWh	¢ per kWh	2.164	2.164	3.048	3.048
Transmission Charge (incl Trans Surch):					
All kWh	¢ per kWh	2.122	2.122	2.122	2.122
RGGI Surcharge	¢ per kWh	0.0921	0.0921	0.0921	0.0921
Societal Benefits Charge	¢ per kWh	0.6050	0.6050	0.6050	0.6050
Securitization Charges:					
TBC	¢ per kWh	0.276	0.276	0.276	0.276
TBC-Tax	¢ per kWh	0.052	0.052	0.052	0.052
Total	¢ per kWh	0.328	0.328	0.328	0.328
Temporary Tax Act Credit	¢ per kWh	(0.2350)	(0.2350)	(0.2350)	(0.2350)
ZEC Recovery Charge	¢ per kWh	0.4000	0.4000	0.4000	0.4000
Basic Generation Service:					
All kWh, Monday to Friday, 10 A.M. to 10 P.M.	¢ per kWh	12.362	9.788	12.362	9.788
All Other kWh	¢ per kWh	5.113	5.019	5.113	5.019
Reconciliation Charge	¢ per kWh	Variable	Variable	Variable	Variable
Minimum Charge:					
The Customer Charge, not less than		$78.00	per contract.	$108.00	per contract.

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 4

Luminaries Charge, per month

Nominal Lumens	Luminaires Type	Watts	Total Wattage	Present Distribution Charge	Proposed Distribution Charge
Street Lighting Luminaires					
5,800	Sodium Vapor	70	108	$7.60	$9.47
9,500	Sodium Vapor	100	142	8.25	10.28
16,000	Sodium Vapor	150	199	10.04	12.51
27,500	Sodium Vapor	250	311	12.82	15.96
46,000	Sodium Vapor	400	488	20.79	25.89
3,000	LED	20-25	23	N/A	8.21
3,900	LED	30-39	35	N/A	8.05
5,000	LED	40-59	50	N/A	8.07
7,250	LED	60-79	68	N/A	8.41
12,000	LED	95-110	103	N/A	9.46
16,000	LED	130-150	140	N/A	9.92
22,000	LED	180-220	200	N/A	14.53
LED Flood Lighitng Luminaires					
15,500	LED	115-130	125	N/A	$11.43
27,000	LED	175-225	205	N/A	14.58
37,500	LED	265-315	290	N/A	15.88

The following luminaires will no longer be installed. Charges are for existing luminaires only.

Nominal Lumens	Luminaires Type	Watts	Total Wattage	Present Distribution Charge	Proposed Distribution Charge
Post Top Luminaries					
16,000	Sodium Vapor-Offset	150	199	$20.29	$25.27
Street Lighting Luminaires					
1,000	Open Bottom Inc	92	92	$5.03	$6.27
4,000	Mercury Vapor	100	127	6.81	8.49
7,900	Mercury Vapor	175	211	8.03	10.00
12,000	Mercury Vapor	250	296	10.44	13.00
22,500	Mercury Vapor	400	459	13.25	16.51
40,000	Mercury Vapor	700	786	20.15	25.10
59,000	Mercury Vapor	1,000	1,105	25.47	31.72

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 4 (Continued)

Nominal Lumens	Luminaires Type	Watts	Total Wattage	Present Distribution Charge	Proposed Distribution Charge
Street Lighting Luminaires (Coninued)					
3,400	Induction	40	45	$7.95	$9.91
5,950	Induction	70	75	8.10	10.09
8,500	Induction	100	110	9.15	11.39
5,890	LED	70	74	8.71	10.84
9,365	LED	100	101	10.69	13.32
Post-Top Luminaires					
4,000	Mercury Vapor	100	130	$10.36	$12.90
7,900	Mercury Vapor	175	215	12.70	15.81
7,900	Mercury Vapor – Off-Set	175	215	14.92	18.57

	Present		Proposed	
Additional Charge:				
UG Svc- Company owned and maintained -	$17.35	per mo.	$21.60	per mo.
UG Svc- Customer owned and maintained -	$4.22	per mo.	$5.26	per mo.
15 Foot Brackets	$0.47	per mo.	$0.59	per mo.
Transmission Charge (incl Trans Surch):	$1.22	per mo.	1.2240	¢ per kWh
RGGI Surcharge	0.0921	¢ per kWh	0.0921	¢ per kWh
Societal Benefits Charge	0.6050	¢ per kWh	0.6050	¢ per kWh
Securitization Charges:				
TBC	0.276	¢ per kWh	0.276	¢ per kWh
TBC-Tax	0.052	¢ per kWh	0.052	¢ per kWh
Total	0.328	¢ per kWh	0.328	¢ per kWh
Temporary Tax Act Credit	(0.235)	¢ per kWh	(0.235)	¢ per kWh
ZEC Recovery Surcharge	0.400	¢ per kWh	0.400	¢ per kWh
Basic Generation Service:				
Summer	5.113	¢ per kWh	5.113	¢ per kWh
Winter	5.019	¢ per kWh	5.019	¢ per kWh
Reconciliation Charge	Variable	¢ per kWh	Variable	¢ per kWh

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 5

		Present		Proposed	
		Summer	Winter	Summer	Winter
Customer Charge:	per month	$4.53	$4.53	$6.50	$6.50
Distribution Charge:					
First 600 kWh	¢ per kWh	4.460	4.460	6.165	6.165
Over 600 kWh	¢ per kWh	5.420	4.460	7.765	6.165
Transmission Charge (incl Trans Surch):					
All kWh	¢ per kWh	2.175	2.175	2.175	2.175
RGGI Surcharge	¢ per kWh	0.0921	0.0921	0.0921	0.0921
Societal Benefit Charge	¢ per kWh	0.6050	0.6050	0.6050	0.6050
Securitization Charges:					
TBC	¢ per kWh	0.276	0.276	0.276	0.276
TBC-Tax	¢ per kWh	0.052	0.052	0.052	0.052
Total	¢ per kWh	0.328	0.328	0.328	0.328
Temporary Tax Act Credit	¢ per kWh	(0.235)	(0.235)	(0.235)	(0.235)
ZEC Recovery Charge	¢ per kWh	0.400	0.400	0.400	0.400
Basic Generation Service:					
First 600 kWh	¢ per kWh	6.793	6.821	6.793	6.821
Over 600 kWh	¢ per kWh	9.165	6.821	9.165	6.821
Reconciliation Charge	¢ per kWh	Variable	Variable	Variable	Variable
Minimum Charge: Monthly		$4.53		$6.50	
Minimum Per Contract		$27.18		$39.00	

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 6

Luminaire Charges for Service Types A and B, monthly

Nominal Lumens	Luminaire Type	Watts	Total Wattage	Present Distribution Charge	Proposed Distribution Charge
Power Bracket Luminaires					
5,800	Sodium Vapor	70	108	$5.34	$7.51
9,500	Sodium Vapor	100	142	6.42	9.02
16,000	Sodium Vapor	150	199	6.89	9.68
3,950	LED	30-44	35	N/A	7.57
5,550	LED	45-59	50	N/A	7.68
7,350	LED	60-70	65	N/A	7.75
Street Lighting Luminaires					
5,800	Sodium Vapor	70	108	$7.43	$10.45
9,500	Sodium Vapor	100	142	8.16	11.46
16,000	Sodium Vapor	150	199	10.02	14.09
27,500	Sodium Vapor	250	311	12.86	18.07
46,000	Sodium Vapor	400	488	21.22	29.83
3,000	LED	20-25	23	N/A	8.21
3,900	LED	30-39	35	N/A	8.05
5,000	LED	40-59	50	N/A	8.07
7,250	LED	60-79	68	N/A	8.41
12,000	LED	95-110	103	N/A	9.46
16,000	LED	130-150	140	N/A	9.92
22,000	LED	180-220	200	N/A	14.53
Flood lighting Luminaires					
46,000	Sodium Vapor	400	488	$21.22	$29.83
15,500	LED	115-130	125	N/A	11.43
27,000	LED	175-225	205	N/A	14.58
37,500	LED	265-315	290	N/A	15.88

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 6 (Continued)

Luminaire Charges for Service Types A and B, monthly

Nominal Lumens	Luminaire Type	Watts	Total Wattage	Present Distribution Charge	Proposed Distribution Charge
The following luminaires will no longer be installed. Charges are for existing luminaires only.					
Post Top Luminaires					
16,000	Sodium Vapor-Offset	150	199	$19.73	$27.73
Power Bracket Luminaires					
4,000	Mercury Vapor	100	127	$8.30	$11.66
7,900	Mercury Vapor	175	215	9.59	13.48
22,500	Mercury Vapor	400	462	15.28	21.48
Street Lighting Luminaires					
4,000	Mercury Vapor	100	127	$9.12	$12.82
7,900	Mercury Vapor	175	211	10.42	14.64
22,500	Mercury Vapor	400	459	16.19	22.75
1,000	Incandescent	-	92	7.41	10.42
3,400	Induction	40	45	8.00	11.24
5,950	Induction	70	75	8.17	11.48
8,500	Induction	100	110	9.20	12.93
5,890	LED	70	74	8.75	12.30
9,365	LED	100	101	10.77	15.14
Flood lighting Luminaires					
12,000	Mercury Vapor	250	296	$13.10	$18.42
40,000	Mercury Vapor	700	786	23.72	33.35
59,000	Mercury Vapor	1,000	1,105	29.55	41.53

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 6 (Continued)

Luminaire Charges for Service Types A and B, monthly

Nominal Lumens	Luminaire Type	Watts	Total Wattage	Present Distribution Charge		Proposed Distribution Charge	
15 Ft Brackets				$0.52	per month	$0.74	per month

	Present		Proposed	
Distribution and Transmission Charges for Service Type C:				
Metered				
Customer Charge (Metered)	$11.53	per month	$14.00	per month
Customer Charge (Unmetered)	2.40	per month	3.00	per month
Distribution Charge	4.992	¢ per kWh	6.251	¢ per kWh
Transmission Charge	1.224	¢ per kWh	1.224	¢ per kWh
RGGI Surcharge	0.0921	¢ per kWh	0.0921	¢ per kWh
Societal Benefit Charge	0.6050	¢ per kWh	0.6050	¢ per kWh
Securitization Charges:				
TBC	0.276	¢ per kWh	0.276	¢ per kWh
TBC-Tax	0.052	¢ per kWh	0.052	¢ per kWh
Total	0.328	¢ per kWh	0.328	¢ per kWh
Temporary Tax Act Credit	(0.235)	¢ per kWh	(0.235)	¢ per kWh
ZEC Recovery Surcharge	0.400	¢ per kWh	0.400	¢ per kWh
Basic Generation Service:				
Summer	5.015	¢ per kWh	5.015	¢ per kWh
Winter	4.985	¢ per kWh	4.985	¢ per kWh
Reconciliation Charge	Variable	¢ per kWh	Variable	¢ per kWh

Minimum Charges:
Type A or B:
Sum of the monthly Distribution and Transmission Charges as specified in RATE – MONTHLY, Part (1a) times twelve.

			Present	Proposed
Type C:	Metered	per month	$11.53	$14.00
		minimum for initial term	138.36	168.00
	Unmetered	per month	2.40	3.00
		minimum for initial term	28.80	36.00

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 7
Primary

		Present Year-round	Proposed Year-round
Customer Charge:	per month	$212.35	$250.00
Distribution Charge:			
Demand Charge			
Period I All kW @	per kW	$2.94	$3.88
Period II All kW @	per kW	0.73	0.96
Period III All kW @	per kW	2.70	3.56
Period IV All kW @	per kW	0.73	0.96
Usage Charge			
Period I All kWh @	¢ per kWh	1.770	1.770
Period II All kWh @	¢ per kWh	1.325	1.325
Period III All kWh @	¢ per kWh	1.770	1.770
Period IV All kWh @	¢ per kWh	1.325	1.325
Transmission Charge (incl Trans Surch):			
Demand Charge			
Period I All kW @	per kW	$2.55	$2.55
Period II All kW @	per kW	0.67	0.67
Period III All kW @	per kW	2.55	2.55
Period IV All kW @	per kW	0.67	0.67
Usage Charge			
All kWh @	¢ per kWh	0.779	0.779
RGGI Surcharge	¢ per kWh	0.0921	0.0921
Societal Benefits Charge	¢ per kWh	0.6050	0.6050
Securitization Charges:			
TBC	¢ per kWh	0.276	0.276
TBC-Tax	¢ per kWh	0.052	0.052
Total	¢ per kWh	0.328	0.328
Temporary Tax Act Credit	¢ per kWh	(0.235)	(0.235)
ZEC Recovery Surcharge	¢ per kWh	0.400	0.400
CIEP Standby Fee	¢ per kWh	0.01599	0.01599

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 7 (Continued)
Primary

		Present Year-round	Proposed Year-round
Basic Generation Service:			
Capacity Obligation Charge			
Summer	$/kW/Month	9.7561	9.7561
Winter	$/kW/Month	9.2151	9.2151
Hourly Energy Charge**	¢ per kWh	4.600	4.600
Ancillary Services	¢ per kWh	0.000	0.000
Retail Margin	¢ per kWh	0.000	0.000
Reconciliation Charge	¢ per kWh	Variable	Variable
Space Heating:			
Distribution Charge			
Summer	¢ per kWh	4.693	6.597
Winter	¢ per kWh	2.902	4.081
Transmission Charge (incl Trans Surch):			
Year-round	¢ per kWh	0.910	0.910

Definition of Rating Periods:

Period I - 10:00 a.m. to 10:00 p.m. prevailing time, Monday through Friday except holidays, June through September.

Period II - 10:00 p.m. to 10:00 a.m. prevailing time, Monday through Friday and all hours on Saturday, Sunday and holidays, June through September.

Period III - 10:00 a.m. to 10:00 p.m. prevailing time, Monday through Friday except holidays, October through May.

Period IV - 10:00 p.m. to 10:00 a.m. prevailing time, Monday through Friday, all hours on Saturday, Sunday and holidays, October through May.

Minimum Charge: The Customer Charge

** Average based on forecast of BGS Prices for 12 ME September, 2019

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 7
High Voltage Distribution

			Present Year-round	Proposed Year-round
Customer Charge:		per month	$2,288.12	$2,288.12
Distribution Charge:				
Demand Charge				
Period I	All kW @	per kW	$0.92	$1.10
Period II	All kW @	per kW	0.21	0.26
Period III	All kW @	per kW	0.84	1.01
Period IV	All kW @	per kW	0.21	0.26
Usage Charge				
Period I	All kWh @	¢ per kWh	0.203	0.203
Period II	All kWh @	¢ per kWh	0.151	0.151
Period III	All kWh @	¢ per kWh	0.203	0.203
Period IV	All kWh @	¢ per kWh	0.151	0.151
Transmission Charge (incl Trans Surch):				
Demand Charge				
Period I	All kW @	per kW	$2.55	$2.55
Period II	All kW @	per kW	0.67	0.67
Period III	All kW @	per kW	2.55	2.55
Period IV	All kW @	per kW	0.67	0.67
Usage Charge				
All kWh @		¢ per kWh	0.779	0.779
RGGI Surcharge		¢ per kWh	0.0921	0.0921
Societal Benefits Charge		¢ per kWh	0.6050	0.6050
Securitization Charges:				
TBC		¢ per kWh	0.276	0.276
TBC-Tax		¢ per kWh	0.052	0.052
Total		¢ per kWh	0.328	0.328
Temporary Tax Act Credit		¢ per kWh	(0.235)	(0.235)
ZEC Recovery Surcharge		¢ per kWh	0.400	0.400
CIEP Standby Fee		¢ per kWh	0.01599	0.01599

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 7 (Continued)
High Voltage Distribution

		Present	Proposed
		Year-round	Year-round
Basic Generation Service:			
Capacity Obligation Charge			
Summer	$/kW/Month	9.7561	9.7561
Winter	$/kW/Month	9.2151	9.2151
Hourly Energy Charge**	¢ per kWh	4.600	4.600
Ancillary Services	¢ per kWh	0.000	0.000
Retail Margin	¢ per kWh	0.000	0.000
Reconciliation Charge	¢ per kWh	Variable	Variable

Definition of Rating Periods:

Period I - 10:00 a.m. to 10:00 p.m. prevailing time, Monday through Friday except holidays, June through September.

Period II - 10:00 p.m. to 10:00 a.m. prevailing time, Monday through Friday and all hours on Saturday, Sunday and holidays, June through September.

Period III - 10:00 a.m. to 10:00 p.m. prevailing time, Monday through Friday except holidays, October through May.

Period IV - 10:00 p.m. to 10:00 a.m. prevailing time, Monday through Friday, all hours on Saturday, Sunday and holidays, October through May.

Definition of Rating Periods:

Minimum Charge: The Customer Charge

** Average based on forecast of BGS Prices for 12 ME September, 2019

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief
General Information Section 17
Construction Charges

Exhibit I - Unit Costs of Underground Construction - Single Phase

			Present	Proposed
1	Trenching	PER FOOT	$ 13.91	$ 11.70
	Pavement Cutting and Restoration	PER FOOT	$ 28.35	$ 28.98
	Blasting and Rock Removal	PER FOOT	ACTUAL LOW BID	ACTUAL LOW BID
	Jack Hammering and Rock Removal	PER FOOT	ACTUAL LOW BID	ACTUAL LOW BID
2	Primary Cable (#2 Aluminum)	PER FOOT	$ 3.33	$ 5.26
3	Secondary Cable			
	A. 4/0 AAC Triplex	PER FOOT	$ 2.30	$ 3.93
	B. 350 kcmil (Aluminum)	PER FOOT	$ 4.20	$ 4.89
4	Service (Installed in conduit, includes tap on, does not include trenching) Up to 200 AMP	PER FOOT	$ 13.50	$ 16.39
	Service (Installed in conduit, includes tap on, does not include trenching) Over 200 AMP	PER FOOT	$ 15.40	$ 18.34
5	Primary Termination /Riser	EACH	$ 2,328.87	$ 2,109.00
	Secondary Termination/Riser	EACH	$ 987.01	$ 1,105.00
6	Primary Junction Enclosure			
	A. Single Phase Boxpad – Unfused	EACH	$ 2,064.45	$ 1,899.00
	B. Single Phase Switch - Fused	EACH	$ 9,097.69	$ 8,681.00
7	Secondary Enclosure (Incl. Terminations)	EACH	$ 661.99	$ 481.00
8	Conduit (2" Schedule 40 PVC, installed)	PER FOOT	$ 2.93	$ 3.16
	Conduit (4" Schedule 40 PVC, installed)	PER FOOT	$ 4.33	$ 4.84
9	Street Light Cable			
	#2 Triplex in Conduit	PER FOOT	$ 4.61	$ 6.54
10	Transformers, Including Pad			
	25 KVA	EACH	$ 4,543.59	$ 5,181.00
	50 KVA	EACH	$ 5,060.79	$ 5,508.00
	75 KVA	EACH	$ 6,757.92	$ 5,880.00
	100 KVA	EACH	$ 7,185.21	$ 6,496.00
	167 KVA	EACH	$ 8,627.92	$ 7,979.00
11	Street Lighting - U/G Feed 30' Fiberglass Pole (including arm & luminaire)	EACH	$ 1,771.67	$ 2,127.69

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief
General Information Section 17
Construction Charges

Exhibit II - Unit Costs of Underground Construction - Three Phase

			Present	Proposed
1	Primary Cable Installation			
	A. 750 kcmil - 600A	PER CIRCUIT FOOT	$ 101.42	$ 100.11
	B. 350 kcmil - 400A	PER CIRCUIT FOOT	$ 55.62	$ 57.54
	C. 2/0 Cu - 200A	PER CIRCUIT FOOT	$ 39.45	$ 31.37
2	Secondary Cable Installation			
	350 kcmil 4-Wire	PER CIRCUIT FOOT	$ 9.37	$ 11.87
3	Service			
	350 kcmil AAC	PER CIRCUIT FOOT	$ 22.09	$ 21.94
4	Primary Termination /Riser			
	A. 750 kcmil - 600A	EACH	$ 10,701.30	$ 1,123.00
	B. 350 kcmil - 400A	EACH	$ 7,686.56	$ 909.00
	C. 2/0 Cu - 200A	EACH	$ 4,324.27	$ 348.00
	D. #2 AI - 100A	EACH	$ 425.00	$ 340.00
5	Primary Junction Box			
	A. 200 A Installation Only	EACH	$ 3,488.65	$ 3,157.00
	B. 2/0 AWG Termination	EACH	$ 904.60	$ 273.00
	C. # 2 AWG Termination	EACH	$ 624.85	$ 277.00
6	Primary Switch - PMH FOR 400A OR 600A			
	A. Switch Installation	EACH	$ 24,529.07	$ 24,287.00
	B. 750 kcmil Termination	EACH	$ 2,955.45	$ 885.00
	C. 350 kcmil Termination	EACH	$ 2,148.93	$ 636.00
	D. 2/0 AWG Termination	EACH	$ 1,229.91	$ 348.00
	E. #2 AWG Termination	EACH	$ 943.53	$ 340.00
7	Primary Switch - Elliot for 200A			
	A. Switch Installation	EACH	$ 14,537.49	$ 16,900.00
	B. 2/0 AWG Termination	EACH	$ 1,768.77	$ 273.00
	C. #2 AWG Termination	EACH	$ 1,511.65	$ 277.00
8	Conduit			
	(4” Schedule 40 PVC, installed)	PER FOOT	$ 4.33	$ 4.84
	(6" Schedule 40 PVC, installed)	PER FOOT	$ 5.76	$ 6.75
9	Transformers, Including Pad			
	150 KVA	EACH	$ 9,076.03	$ 14,137.00
	300 KVA	EACH	$ 12,851.22	$ 16,911.63
10	Concrete Pullbox			
	Materials	EACH	$ 11,084.27	$ 10,113.00
	Labor	EACH	ACTUAL LOW BID	ACTUAL LOW BID
11	Concrete Manhole			
	Materials	EACH	$ 21,468.77	$ 19,733.00
	Labor	EACH	ACTUAL LOW BID	ACTUAL LOW BID
12	Trenching - Mainline Construction	PER FOOT	ACTUAL LOW BID	ACTUAL LOW BID

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief
General Information Section 17
Construction Charges

Exhibit III - Unit Costs of Overhead Construction - Single Phase and Three Phase

			Present	Proposed
1	Pole Line (Includes 45 ft. Poles Anchors & Guys)	PER FOOT	$ 8.71	$ 15.03
2	Primary Wire			
	A. Single Phase (3/0 ACSR)	PER FOOT	$ 4.18	$ 5.31
	B. Three Phase (477 kcmil Aluminum)	PER FOOT	$ 14.43	$ 15.17
	C. Three Phase (3/0 ACSR)	PER FOOT	$ 11.79	$ 13.13
	D. Neutral	PER FOOT	$ 2.55	$ 3.34
3	Secondary Wire			
	A. 3-Wire (2/0 TX)	PER FOOT	$ 4.38	$ 6.26
	B. 4-Wire (2/0 QX)	PER FOOT	$ 4.98	$ 6.85
4	Service - Single Phase			
	Up To 200 AMP	PER FOOT	$ 4.42	$ 3.73
	Over 200 AMP	PER FOOT	$ 5.27	$ 4.54
5	Service - Three Phase			
	Up To 200 AMP	PER FOOT	$ 5.29	$ 4.60
	Over 200 AMP	PER FOOT	$ 5.89	$ 5.10
6	Transformers			
	25 KVA - Single Phase	EACH	$ 1,804.88	$ 1,996.00
	50 KVA - Single Phase	EACH	$ 2,262.53	$ 2,580.00
	100 KVA - Single Phase	EACH	$ 3,177.36	$ 4,977.00
	3-25 KVA - Three Phase	EACH	$ 6,139.71	$ 7,201.00
	3-50 KVA - Three Phase	EACH	$ 7,511.76	$ 8,952.00
	3-100 KVA - Three Phase	EACH	$ 10,024.90	$ 15,308.00
7	Street Light Luminaire	EACH	$ 465.64	$ 617.00

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief
General Information Section 17
Construction Charges
Exhibit IV - Metering Costs

METER TYPE	Present	Proposed
Residential		
120/240 - Single Phase	$ 108.99	$ 159.20
120/208 - Single Phase	$ 138.59	$ 161.06
Current Transformer - 120/240 - Single Phase	$ 1,371.03	$ 836.68
Other*		
Non-Residential		
120/240 - Single Phase	$ 108.99	$ 159.20
120/208 - Single Phase	$ 138.59	$ 161.06
120/240 - Single Phase - Demand Metered	$ 160.66	$ 159.85
120/208 - Single Phase - Demand Metered	$ 181.69	$ 159.20
Other Secondary - Self Contained - Secondary	$ 181.69	$ 159.20
Up to 1200 AMP - Current Transformer - Less than 480 Volts	$ 1,496.59	$ 1,430.48
Greater than 1200 AMP - Current Transformer - Less than 480 Volts	$ 1,551.69	$ 1,430.48
Up to 1200 AMP - Current Transformer - 480 Volts	$ 1,844.20	$ 1,480.48
Greater than 1200 AMP - Current Transformer - 480 Volts	$ 1,899.29	$ 1,480.48
Primary Voltage*		

* Cost to be determined on a case-by-case basis.

Exhibit D

ROCKLAND ELECTRIC COMPANY

Statement of Revenue Derived in 2018
From Customers Whose Rates Would be Affected

CUSTOMER CLASSIFICATION	2018
Residential (SC Nos. 1, 3, and 5)	$115,776,847
General Service (SC Nos. 2 and 7)	67,846,843
Street Lighting (SC No. 4)	1,266,725
Private Area Lighting (SC No. 6)	824,567
TOTAL	$185,714,983

Exhibit P-1

ROCKLAND ELECTRIC COMPANY

INDEX OF SCHEDULES

Balance Sheets, Retained Earnings, Book Value, Etc.

Schedule	Title of Schedules	Witness
1	Comparative Balance Sheets	Accounting Panel
2	Comparative Statement of Income	"
3	Statement of Retained Earnings	"
4	Intercompany Account - Payable to Orange and Rockland Utilities, Inc. (Year 2018)	"
5	Statement of Charges Made by Orange and Rockland Utilities, Inc. to Rockland Electric Company Under Terms of Joint Operating Agreement (Year 2018)	"

ASSETS AND OTHER DEBITS	DECEMBER 31, 2016	DECEMBER 31, 2017	DECEMBER 31, 2018	MARCH 31, 2019
Utility Plant				
Electric Plant in Service	$352,630,568	$364,525,914	$392,711,881	$395,210,241
Electric Plant Held for Future Use	$208,709	$208,709	$208,709	$208,709
Construction Work in Progress	6,959,219	$15,657,245	$17,145,365	$19,302,455
Total Utility Plant	**359,798,496**	**380,391,868**	**410,065,955**	**414,721,405**
Accum. Provision for Depreciation				
Electric Plant in Service	83,860,129.54	85,804,125	88,687,118	85,766,011.98
Retirement Work in Progress	(5,732)	(64,819)	(107)	(7,459)
Electric Plant Held for Future Use	-	-	-	-
Total Accumulated Provision for Depreciation	**83,854,398**	**85,739,306**	**88,687,010**	**85,758,553**
Net Utility Plant	**275,944,098**	**294,652,562**	**321,378,945**	**328,962,852**
Other Property and Investments				
Investments in Subsidiary Companies	231,500	231,500	231,500	231,500
Other Investments	-	-	-	-
Total Other Property and Investments	**231,500**	**231,500**	**231,500**	**231,500**
Cash	(147,881)	308,775	306,183	700,875
Special Deposits	-	-	-	
Working Funds	-	-	-	-
Temporary Cash Investments	31,775,000	40,450,000	17,425,000	9,725,000
Customer Accounts Receivable	17,544,271	17,243,036	20,302,280	19,709,638
Other Accounts Receivable	1,079,736	4,146,307	2,850,293	1,241,675
Accumulated Provision for Uncollectible Accounts	(478,979)	(826,260)	(552,343)	(512,188)
Accounts Receivable from Associated Companies	11,335,296	197,294	7,122,116	7,830,362
Materials and Supplies	2,972,568	3,278,702	3,388,576	3,488,151
Nuclear Materials Held for Sale	-	-	-	-
Prepayments	1,378,936	609,586	1,606,966	1,992,851
Unbilled Revenues	8,791,632	8,202,207	4,260,048	3,078,233
Miscellaneous Current and Accrued Assets	-	-	-	-
Derivative Instrument Asset Hodges	-	77,672	320,263	226,033
Total Current and Accrued Assets	**74,250,578**	**73,687,318**	**57,029,383**	**47,480,630**
Deferred Debits				
Deferred Fuel Costs	-	-	-	-
Unamortized Debt Expense	-	-	-	-
Other Regulatory Assets	49,679,280	14,610,809	20,227,047	19,769,805
Clearing Accounts	-	-	-	(7,303)
Miscellaneous Deferred Debits	708,494	1,054,934	910,598	1,129,371
Research and Development Expenses	-	-	-	-
Accumulated Deferred Federal Income Tax	9,781,386	14,476,955	11,287,168	12,733,723
Total Deferred Debits	**60,169,160**	**30,142,698**	**32,424,813**	**33,625,596**
Total Assets and Other Debits	**$410,595,337**	**$398,714,078**	**$411,064,640**	**$410,300,578**

LIABILITIES AND OTHER CREDITS	DECEMBER 31, 2016	DECEMBER 31, 2017	DECEMBER 31, 2018	MARCH 31, 2019
Proprietary Capital				
Common Stock Issued	$11,200,000	$11,200,000	$11,200,000	$11,200,000
Capital Stock Expense	-	-	-	-
Retained Earnings	248,416,993	261,715,007	276,282,289	277,428,823
Total Proprietary Capital	**259,616,993**	**272,915,007**	**287,482,289**	**288,628,823**
Long Term Debt				
Bonds	-	-	-	-
Unamortized Discount on Long Term Debt	-	-	-	-
Total Long Term Debt	**-**	**-**	**-**	**-**
Other Noncurrent Liabilities				
Provision for Injuries and Damages	-	2,463,816	-	-
Obligations Under Capital Leases - Noncurrent	50,000	-	-	17,984
Provision for Pensions and Benefits				
Total Noncurrent Liabilities	**50,000**	**2,463,816**	**-**	**17,984**
Current and Accrued Liabilities				
Long Term Debt Due Within one Year	-	-	-	-
Accounts Payable	9,962,523	9,170,877	9,218,064	12,900,924
Accounts Payable to Associated Companies	8,299,314	9,327,631	10,497,852	6,387,538
Customer Deposits	6,310,543	3,294,584	2,834,055	2,810,174
Taxes Accrued	790,648	1,105,142	(74,692)	(53,982)
Interest Accrued	168,389	229,093	25,742	36,764
Tax Collections Payable	2,637	79,427	107,441	107,441
Miscellaneous Current and Accrued Liabilities	829,306	2,023,405	1,613,954	2,531,684
Obligations Under Capital Leases - Current	-	-	-	41,993
Derivative Instrument Liabilities - Hedges	798,482	-	-	-
Total Current and Accrued Liabilities	**27,161,841**	**25,230,159**	**24,222,416**	**24,762,537**
Deferred Credits				
Customer Advances for Construction	311,191	573,462	1,254,145	1,093,498
Other Deferred Credits	616,911	1,654,545	2,745,183	1,236,837
Regulatory Liabilities	11,100,175	28,779,934	24,487,763	21,147,104
Accumulated Deferred Income Taxes-Other Pro	82,785,333	60,398,018	65,933,781	66,716,612
Accumulated Deferred Income Taxes-Other	28,602,955	6,399,637	4,680,214	6,447,831
Accumulated Deferred Investment Tax Credits	349,938	299,500	258,849	249,353
Total Deferred Credits	**123,766,502**	**98,105,096**	**99,359,935**	**96,891,234**
Total Liabilities and Other Credits	**$410,595,337**	**$398,714,078**	**$411,064,640**	**$410,300,578**

Utility Operating Income	12 MONTHS ENDED DECEMBER 31, 2016	DECEMBER 31, 2017	DECEMBER 31, 2018	MARCH 31, 2019
Operating Revenue	$183,987,564	$173,732,353	$175,160,210	$173,297,486
Operating Expenses:				
Operation Expenses	141,651,968	129,861,618	137,759,907	137,336,462
Maintenance Expenses	13,916,082	13,844,959	12,215,002	10,422,818
Depreciation Expense	8,888,121	8,123,366	8,186,405	8,343,952
Amortization of Other Limited Term Plant	34,453	35,169	34,887	34,887
Taxes Other than Income Taxes	1,819,106	1,849,478	1,797,149	1,660,208
Income Taxes				-
Federal Income Taxes	5,577,522	5,522,531	1,761,475	999,813
NJ State Income Taxes	1,676,956	1,829,117	1,053,648	1,052,057
Gain/loss on disposition of utility plant	-	-	-	-
Total Utility Operating Expenses	**173,564,207**	**161,066,237**	**162,808,471**	**159,850,195**
Net Utility Operating Income	**10,423,356**	**12,666,116**	**12,351,739**	**13,447,291**
Other Income				
Equity in Earnings of Subsidiary Companies		-	-	-
Investment Income	127,556	306,000	509,549	474,093
Allowance for Other Funds Used During Construction (AFDC)	556,348	356,805	541,795	512,284
Miscellaneous Non-Operating Income	-	-	-	-
Gain on Disposition of Properties				
Total Other Income	**683,904**	**662,805**	**1,051,344**	**986,377**
Taxes Applicable to Other Income Deductions				
Taxes Other than Income Taxes	18,470	18,954	19,245	19,296
Income Taxes - Non Operating	(916,833)	(61,325)	(880,261)	(850,259)
Miscellaneous Income Deductions	206,447	189,091	171,830	231,582
Total Taxes Applicable to Other Income Deductions	**(691,915)**	**146,720**	**(689,186)**	**(599,381)**
Net Other Income and Deductions	**1,375,819**	**516,085**	**1,740,531**	**1,585,757**
Interest Charges				
Interest on Long Term Debt	-	-	-	-
Amortization of Debt Discount and Expense	-	-	-	-
Other Interest Expense	59,524	68,253	(180,028)	(186,222)
Allowance for Borrowed Funds Used During Construction	(272,738)	(184,065)	(294,984)	(273,459)
Total Interest Charges	**(213,215)**	**(115,812)**	**(475,013)**	**(459,681)**
Net Income	**$12,012,391**	**13,298,014**	**14,567,282**	**$15,492,730**

RETAINED EARNINGS	DECEMBER 31, 2016	DECEMBER 31, 2017	DECEMBER 31, 2018	MARCH 31, 2019
Retained Earnings -				
Beginning of Period	236,404,603	$248,416,993	$261,715,007	$276,282,289
Adj. to Capital Stock Expense	-	-	-	-
Balance Transferred from Income (A)	12,012,391	13,298,014	14,567,282	15,492,730
Dividends Declared:				
Preferred Stock	-	-	-	-
Common Stock	-	-	-	
Total Dividends Declared	**-**	**-**	**-**	**-**
Net Change	**12,012,391**	**13,298,014**	**14,567,282**	**15,492,730**
Retained Earnings -				
End of Period	**$248,416,993**	**$261,715,007**	**$276,282,289**	**$ 291,775,019**
Check vs Balance Sheet Retained Earnings	**-**	**-**	**-**	**14,346,195.59**

UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS				
Unappropriated Undistributed Subsidiary Earnings -				
Beginning of Period	$0	$0	$0	$0
Equity in Earnings for Period (A)	-	-	-	-
Unappropriated Undistributed Subsidiary Earnings -				
End of Period	**$0**	**$0**	**$0**	**$0**

Note:
(A) Reconciliation of Net Income to Balance Transferred from Net Income:

Net Income	$12,012,391	$13,298,014	$14,567,282	$15,492,730
Equity in Earnings of Subsidiary Companies	-	-	-	-
Balance Transferred from Net Income	$12,012,391	$13,298,014	$14,567,282	$15,492,730

ROCKLAND ELECTRIC COMPANY
Intercompany Account - Payable to Orange & Rockland Utilities, Inc.

Year 2018

Payable to Orange and Rockland Utilities, Inc. at January 1, 2018		8,698,002 *	Credit
Power Supply Agreement FERC Rate Schedule No.61			
Cost of Electricity Purchased.			
Summary of Charges - Article 3 (A):			
Expense:			
Sec. 3.11 - Power Production Expense	8,385,751		
Sec. 3.12 - Transmission Expense	2,833,568		
Sec. 3.13 - Distribution Expense	2,530		
Sec. 3.14 - Workmen's Compensation, Public Liability Insurance & FICA	83,656		
Total	11,305,506		
Fixed Costs:			
Sec. 3.21 - Return on Investment	3,602,105		
Sec. 3.22 - Federal Income Tax	485,730		
Sec. 3.23 - Property Insurance	4,520		
Sec. 3.24 - Depreciation	1,420,586		
Sec. 3.25 - Amortization Expense	32,860		
Sec. 3.26 - Property Taxes	2,642,808		
Total	8,188,609		
Sec. 3.3 - Credit for Sales to Other Utilities	0		
Total Charges Under Power Supply Agreement		19,494,115	Credit
Joint Operating Agreement (BPU Docket No. 769-937 dated February 5, 1976) Cost of Shared Operations and Jointly Used Property Per Detail on Schedule 5		94,772,389	Credit
Payments Made During Year		(112,894,035)	Debit
Payable to Orange and Rockland Utilities, Inc. at December 31, 2018		10,070,471	Credit

(A) Net of Reimbursements to Rockland Electric Company in Accordance with Article 8 of Power Supply Agreement

* The beginning balance is the net of Intercompany Payables and Receivables with Orange and Rockland Utilities.

ROCKLAND ELECTRIC COMPANY
Statement of Charges Made by Orange and Rockland Utilities, Inc. to
Rockland Electric Company Under Terms of Joint Operating Agreement
Year 2018

	Direct Charges	Allocated Charges	Total Charges
ARTICLE 2. Charges for Operations			
Operation and Maintenance Expenses	6,113,911	22,130,496	28,244,407
Other Charges	58,981,552	1,371,288	60,352,840
Total	65,095,464	23,501,784	88,597,248
ARTICLE 3.Charges for Jointly Used Property			
Investment Costs	2,167,870	0	2,167,870
Federal Income Taxes	413,823	0	413,823
Depreciation Expenses	2,703,188	0	2,703,188
Property Taxes	878,433	0	878,433
Insurance	11,827	0	11,827
Total	6,175,141	0	6,175,141
Total Charges During Year	71,270,605	23,501,784	94,772,389

ROCKLAND ELECTRIC COMPANY
Statement of Charges Made by Orange and Rockland Utilities, Inc. to
Rockland Electric Company Under Terms of Joint Operating Agreement
Year 2018

	Direct Charges	Allocated Charges	Total Charges
Operation and Maintenance Expenses			
Other Power Supply Expense			
Purchased Power	0	0	0
	0	0	0
Transmission Expenses - Operation			
Operation Supervision and Engineering	27,526	0	27,526
Load Dispatching	19,993	0	19,993
Station Expenses	128,474	0	128,474
Overhead Line Expenses	80,451	0	80,451
Miscellaneous Transmission Expense	378,602	0	378,602
Rents	0	0	0
Total Operation	635,047	0	635,047
Transmission Expenses - Maintenance			
Maintenance of Structures Transmission	1,260	0	1,260
Maintenance of Station Equipment	0	0	0
Maintenance of Overhead Lines	567,994	0	567,994
Maintenance of Underground Lines	2,049	0	2,049
Maintenance of Transmission Plant	0	0	0
Total Maintenance	571,304	0	571,304
Total Transmission Expenses	1,206,351	0	1,206,351
Distribution Expenses - Operation			
Operation Supervision and Engineering	412,156	0	412,156
Station Expenses	151,079	0	151,079
Overhead Line Expenses	51,853	0	51,853
Underground Line Expenses	62,489	0	62,489
Street Lighting And Signal System Expenses		0	0
Meter Expenses	183,664	0	183,664
Customer Installations Expenses	807	0	807
Miscellaneous Distribution Expenses	124,671	0	124,671
Rents	761	0	761
Total Operation	987,480	0	987,480
Distribution Expenses - Maintenance			
Maintenance of Station Equipment	1,762	0	1,762
Maintenance of Overhead Lines	2,573,653	0	2,573,653
Maintenance of Underground Lines	279,882	0	279,882
Maintenance of Street Lighting & Sig. Sys.	257,984	0	257,984
Maintenance of Meters	0	0	0
Total Maintenance	3,113,281	0	3,113,281
Total Distribution Expenses	4,100,761	0	4,100,761

ROCKLAND ELECTRIC COMPANY
Statement of Charges Made by Orange and Rockland Utilities, Inc. to
Rockland Electric Company Under Terms of Joint Operating Agreement
Year 2018

	Direct Charges	Allocated Charges	Total Charges
Customer Accounts Expenses - Operation			
Supervision	0	0	0
Meter Reading Expenses	0	757,958	757,958
Customer Records & Collection Expenses	86,723	3,651,870	3,738,592
Uncollectible Accounts	0	0	0
Total Customer Accounts Expenses	86,723	4,409,827	4,496,550
Customer Service & Information Expenses - Operation			
Informational Advertising Expenses	1,486	88,890	90,376
Miscellaneous Customer Service Expenses	529,916	209,555	739,471
Total Customer Svc & Info Expense-Operation	531,402	298,445	829,847
Sales Expense			
Supervision	0	0	0
Demonstration & Selling Expenses	0	0	0
Misc. Sales Expense	4,465		4,465
Sales Expense-Promotional	0	0	0
Total Customer Service & Inform. Expenses	4,465	0	4,465
Administrative and General Expenses - Operation			
Administrative and General Salaries	0	2,774,061	2,774,061
Office Supplies and Expenses	53,471	858,372	911,844
Administrative Expenses Transferred - Cr.	0	3,188,341	3,188,341
Outside Services Employed	13,325	285,124	298,448
Property Insurance	0	78,958	78,958
Injuries and Damages	0	290,678	290,678
Employee Pensions and Benefits	1,536	9,374,305	9,375,841
Regulatory Commission Expenses	35,783	99,202	134,985
Duplicate Charges	0	3	3
Miscellaneous General Expenses	80,096	275,531	355,627
Rents	0	2,798	2,798
Transportation Expenses	0	0	0
Total Operation	184,210	17,227,372	17,411,582

ROCKLAND ELECTRIC COMPANY
Statement of Charges Made by Orange and Rockland Utilities, Inc. to
Rockland Electric Company Under Terms of Joint Operating Agreement
Year 2018

	Direct Charges	Allocated Charges	Total Charges
Administrative and General Expenses - Maintenance			
Maintenance of General Plant	0	194,852	194,852
Total Administrative and General Exp.	184,210	17,422,224	17,606,434
Total Operations and Maintenance	6,113,911.47	22,130,496	28,244,407
Other Charges for Operations			
Income Statement Accounts			
Taxes Other than Income	0	1,273,180	1,273,180
Other Interest Income	0	0	0
Other Miscellaneous Income	0	0	0
Miscellaneous Income Deductions	53,768	98,108	151,876
Miscellaneous Service Revenues	0	0	0
Other Electric Revenue	0	0	0
Balance Sheet Accounts			
Electric Plant in Service	24,667,193	0	24,667,193
Accumulated Provision for Depreciation	2,131,194	0	2,131,194
Current Assets	50,840	0	50,840
Regulatory Assets and Other Deferred Debits	32,112,454	0	32,112,454
Current Liabilities	(43,881)	0	(43,881)
Operating Reserves	0	0	0
Customer Advances	9,984	0	9,984
Total Other Charges for Operations	58,981,552	1,371,288	60,352,840

ROCKLAND ELECTRIC COMPANY

Index of Schedules

Cost of Service for the Twelve Months Ended September 30, 2019
for Operating Income, Rate Base and Rate of Return

Witness - Accounting Panel

Schedule	Title of Schedules
Summary 1	Elimination of Electric Transmission Revenues, Expenses & Rate Base
Summary 2	Electric Distribution Cost of Service
Summary 3	Computation of Distribution Revenue Requirement
Summary 4	Adjustments to the Cost of Service
1	Operating Revenue - Weather Normalization / Annualization of Storm Hardening Revenues
2	Operating Revenue - Annualization of Added Customers
3	Other Operating Revenues - Three Year Average
4	Operation and Maintenance Expenses - Wages and Salaries
5	Operation and Maintenance Expenses - Employee Health and Insurance Benefits
6	Operation and Maintenance Expenses - Pension
7	Operation and Maintenance Expenses - Post Retiree Expenses Other Than Pension Costs ("OPEB")
8	Operation and Maintenance Expenses - Interest on Customer Deposits
9	Operation and Maintenance Expenses - Rate Case Cost Amortization
10	Operation and Maintenance Expenses - AMI Expenses
11	Operation and Maintenance Expenses - Customer Uncollectible Write-Off
12	Operation and Maintenance Expenses - Danger Tree Program / Annual Funding for Storm Reserve
13	Operation and Maintenance Expenses - Equalize Return Component of Intercompany Billings
14	Operation and Maintenance Expenses - Amortization of Storm & Management Audit Costs
15	Operation and Maintenance Expenses - Expiring Amortizations of Regulatory Deferral
16	Depreciation Expense - Annualization of Current and Proposed Depreciation Rates
17	Depreciation Expense - Post Test Year Additions at Current and Proposed Depreciation Rates
18	Deprecation Expense - Amortization of Deferred Negative Net Salvage Balance
19	Depreciation Expense - Provision for Annual Salvage Cost
20	Taxes Other Than Income Taxes
21	State Corporate Business Tax Expense
22	Federal Income Tax Expense
23	Interest Synchronization

ROCKLAND ELECTRIC COMPANY

Electric Cost of Service

Elimination of Electric Transmission Revenues, Expenses & Rate Base

For the Twelve Months Ended September 30, 2019

6 Months Actual + 6 Months Forecast

($000s)

	a Total	b Transmission	c=a-b Distribution
Operating Revenues:			
Sales of Electricity	$166,702	$17,535	$ 149,167
Other Operating Revenues	($3,148)	($907)	(2,241)
Total Operating Revenues	163,554	16,628	146,926
Operating Expenses:			
Purchased Power Supply Expense			
Purchased Power - PJM	$77,020	-	77,020
Purchased Power - NYISO	6,230	-	6,230
Intercompany PSA	11,951	12,171	(220)
Deferred Purchased Power	(2,596)	-	(2,596)
Other Operation and Maintenance Expenses			
Transmission Expenses	$3,126	$3,126	-
Regional / Market Expenses	89	-	89
Distribution Expenses	14,183	-	14,183
Customer Accounts Expenses	6,611	-	6,611
Customer Service and Informational Expenses	10,137	-	10,137
Sales Promotion Expenses	1	-	1
Administrative & General Expenses	18,888	1,577	17,311
Depreciation and Amortization Expense	8,689	768	7,921
Taxes Other than Income Taxes	1,758	0	1,758
Total Operating Expenses	156,087	17,643	138,444
Operating Income Before Income Taxes	7,467	(1,015)	8,482
Income Taxes			
State Income Tax	70	(130)	200
Federal Income Tax	(2,546)	(300)	(2,246)
Total Income Taxes	(2,476)	(430)	(2,046)
Operating Income After Income Taxes	$ 9,943	$ (585)	$ 10,528
Rate Base	$ 260,465	$ 16,921	$ 243,544

ROCKLAND ELECTRIC COMPANY
Electric Distribution Cost of Service
For the Twelve Months Ended September 30, 2019
6 Months Actual + 6 Months Forecast
($000s)

	c	d	e=c+d	f	g=e+f
	12 Months Ended 9/30/2019	Adjustments	Test Year as Adjusted	Proposed Rate Change	Test Year as Adjusted for Proposed Rate Increase
Operating Revenues:					
Sales of Electricity	$ 149,167	$ (298)	$ 148,869	$ 19,906	$ 168,775
Other Operating Revenues	(2,241)	185	(2,056)		(2,056)
Total Operating Revenues	146,926	(113)	146,813	19,906	166,718
Operating Expenses:					
Purchased Power Supply Expense	83,030	-	83,030		83,030
Deferred Purchased Power	(2,596)	-	(2,596)		(2,596)
Other Operation and Maintenance Expenses	48,332	6,019	54,351	36	54,387
Depreciation and Amortization Expense	7,921	2,025	9,946		9,946
Taxes Other than Income Taxes	1,758	45	1,803		1,803
Total Operating Expenses	138,444	8,089	146,533	36	146,569
Operating Income Before Income Taxes	8,482	(8,202)	280	19,870	20,149
Income Taxes					
State Income Tax	200	(756)	(556)	1,788	1,232
Federal Income Tax	(2,246)	(1,625)	(3,871)	3,797	(74)
Total Income Taxes	(2,046)	(2,381)	(4,427)	5,585	1,158
Operating Income After Income Taxes	$ 10,528	$ (5,821)	$ 4,707	$ 14,284	$ 18,991
Rate Base	$ 243,544	$ 7,654	$ 251,198		$ 251,198
Rate of Return	4.32%		1.87%		7.56%

ROCKLAND ELECTRIC COMPANY
Computation of Distribution Revenue Requirement
For the Twelve Months Ended September 30, 2019
($000s)

Rate Base	$251,198
Rate of Return	7.56%
Total Return Required	18,991
Earned Return	4,707
Additional Return Required	14,284
Retention Factor*	71.76%
Additional Revenue Requirement	$19,906

* Calculation of Retention Factor:		%	
Additional Revenue		100.00%	$19,906
Uncollectible Factor	0.178%	0.18%	36
		99.82%	19,870
New Jersey Corporate Business Tax @	9.0%	8.98%	1,788
		90.84%	18,081
Federal Income Tax @	21.0%	19.08%	3,797
		71.76%	$14,284

ROCKLAND ELECTRIC COMPANY
Adjustments to the Cost of Service
For the Twelve Months Ended September 30, 2019
6 Months Actual + 6 Months Forecast
($000s)

Cost of Service Line Item	Adjustment Number	Description	Amount
Sales of Electricity			
	1 (a)	To reflect weather normalization of sales and revenues	$ (604)
	1(b)	To annualize Storm Hardening surcharge revenues	176
	2	To reflect annualization of added customers	130
			(298)
Other Operating Revenues			
	3	To reflect three year average of other operating revenues	185
			185
Purchased Power Supply Expense			-
			-
Deferred Purchased Power			-
			-
Other Operation and Maintenance Expenses			
	2	To reflect annualization of added customers	-
	4 (a)	To reflect increases in wages and salaries	581
	4 (b)	To reflect increases in wages and salaries for additional employees	131
	5	To reflect change in employee health and benefit insurance costs	123
	6	To reflect change in employee pension costs	(189)
	7	To reflect change in post retiree expenses other than pension costs ("OPEBs")	(116)
	8	To reflect interest on customer deposits	55
	9	To reflect rate case cost amortization	127
	10	To eliminate AMI customer expenses from Test Year	(94)
	11	To reflect actual customer uncollectible write-off experience	(72)
	12 (a)	To reflect adjustment to Operations	500
	12 (b)	To increase annual funding for the Storm Reserve	750
	13	To equalize return component of intercompany billings	(450)
	14 (a)	To reflect storm cost amortizations in Rate Year	4,437
	14 (b)	To reflect Managment Audit amortizations in Rate Year	218
	15	To eliminate regulatory amortization from Test Year	18
			6,019
Depreciation and Amortization Expense			
	16	To annualize depreciation and reflect revised depreciation rates	855
	17	To reflect post Test Year depreciation expense	206
	18 (a)	To reduce recovery for expiring depreciation reserve deficiencies	(449)
	18 (b)	To update provision for net salvage	1,068
	19	To amortize meters retired as part of AMI Project	345
			2,025
Taxes Other than Income Taxes			
	20	To reflect increases in payroll taxes	$45
			45
State Income Tax	21	Calculation of state income tax expense	(756)
Federal Income Tax	22	Calculation of federal income tax expense	(1,625)
Interest Synchronization	23	Calculation of interest synchronization	$197

ROCKLAND ELECTRIC COMPANY
Statement in Support of Adjustments No. (1a & 1b)
To Sales of Electricity
For the Twelve Months Ended September 30, 2019

To Reflect Weather Normalization Of Sales And Revenues

Month / Year	Actual Volumes (MWh)	Weather Norm Adjustment (MWh)	Weather Normalized Sales (MWh)	Delivery Average Price (cents/kWh)	Weather Revenue Impact ($000)
October 2018	117,041	7,481	109,560	5.799	$ 433.8
November	113,802	3,578	110,224	5.404	193.4
December	116,604	(549)	117,153	5.512	(30.3)
January 2019	122,747	54	122,693	5.413	2.9
February	105,411	(621)	106,032	5.491	(34.1)
March	109,586	678	108,908	5.673	38.5
April	106,606	-	106,606	5.188	-
May	114,984	-	114,984	5.224	-
June	134,484	-	134,484	5.316	-
July	169,612	-	169,612	5.507	-
August	162,012	-	162,012	5.525	-
September	128,834	-	128,834	5.478	-
Incremental weather related revenues	1,501,723	10,621	1,491,102		604.2
Normalize -- To eliminate weather related sales					(604.2)
Rounded					$ (604)

To Annualize Storm Hardening Surcharge Revenues

Month / Year	Weather Normalized Sales (MWh)	Delivery Average Price (cents/kWh)	Weather Revenue Impact ($000)
October 2018	109,560	0.260	$ 28.5
November	110,224	0.260	28.7
December	117,153	0.260	30.5
January 2019	122,693	0.260	31.9
February	106,032	0.260	27.6
March	108,908	0.260	28.3
Eliminate Smart Grid Surcharge	674,570		$ 175.5
Rounded			$ 176.0

Exhibit P-2
Schedule 2

ROCKLAND ELECTRIC COMPANY
Statement in Support of Adjustment No. (2)
To Sales of Electricity and Expenses
For the Twelve Months Ended September 30, 2019

To Reflect Annualization Of Added Customers

	Service Classification		
	Residential (SC 1, 3, 5)	Secondary (SC 2)	
Customers at December 31, 2018	64,900	8,798	
Average Customers for Test Year	64,866	8,744	
Increase in Number of Customers	34	54	
Average Annual Usage per Customer	11,583	60,822	
Additional Usage (kWh)	393,822	3,284,388	
Average Delivery Rate	$ 0.06143	$ 0.04576	
Additional Revenue	24,192	150,294	$ 174,486
Rounded ($000s)			
Annual Cost Per Customer Per ECOS Study	$ 276.24	$ 650.28	
Additional Customer Cost	9,392	35,115	44,507
Rounded ($000s)			
Increase in Operating Income Before Income Tax			$ 129,979
Rounded ($000s)			$ 130

Exhibit P-2
Schedule 3

ROCKLAND ELECTRIC COMPANY
Statement in Support of Adjustment No. (3)
To Other Operating Revenues
For the Twelve Months Ended September 30, 2019

To Reflect Three Year Average Of Other Operating Revenues

Account	Description	Twelve months ending December-16	December-17	December-18	Rounded Average
451	Misc. Service Revenue	$ (32,098)	$ (28,283)	$ (36,714)	$ (32,000)
454	Electric Rents	(440,006)	(463,848)	(537,117)	(480,000)
456	Other Misc. Revenues	7,278,689	6,897,844	8,927,670	7,701,000
	Total	6,806,586	6,405,713	8,353,839	7,189,000
	Normalizing Adjustments				
451	Misc. Service Revenue	-	-	-	
454	Electric Rents	-	-	-	
456	Other Operating Revenues	-	-	-	
	Eliminate RGGI True-up	(447,657)	(207,708)	16,615	
	Eliminate TBC Revenue Adj.	(6,963,757)	(6,817,517)	(7,173,317)	
	Eliminate SREC	-	-	(1,027,015)	
	Eliminate Tax Law Change	-	-	(921,885)	
	Total	(7,411,414)	(7,025,225)	(9,105,602)	
	Adjusted				
451	Misc. Service Revenue	(32,098)	(28,283)	(36,714)	(32,000)
454	Electric Rents	(440,006)	(463,848)	(537,117)	(480,000)
456	Other Misc. Revenues	(132,725)	(127,381)	(177,932)	(146,000)
	Total	(604,828)	(619,512)	(751,763)	(658,000)
	Flip sign to show the revenues as a positive number				658,000

Other Operating Revenues For the Twelve Months Ended September 30, 2019	472,539
Adjustment	$ 185,461
Rounded ($000s)	$ 185

ROCKLAND ELECTRIC COMPANY

Statement in Support of Adjustment No. (4a)
To Distribution Operation and Maintenance Expenses
For the Twelve Months Ended September 30, 2019

To Reflect Increases In Wages And Salaries

Wage and Salary Increases:

(a)	Weekly Paid Employees									
	Consolidated wage increase effective June 1, 2019 =							$2,375,758		
	Portion applicable to RECO O&M Expense:									
	$2,375,758	x	8	/	12	x	7.76%		$	122,906
(b)	Weekly Paid Employees									
	Consolidated wage increase effective June 1, 2020 =							$2,456,443		
	Portion applicable to RECO O&M Expense:									
	$2,456,443					x	7.76%			190,620
(c)	Monthly Paid Employees									
	Consolidated wage increase effective April 1, 2019 =							$2,249,772		
	Portion applicable to RECO O&M Expense:									
	$2,249,772		6	/	12	x	7.76%			87,291
(d)	Monthly Paid Employees									
	Consolidated wage increase effective April 1, 2020							$2,317,266		
	Portion applicable to RECO O&M Expense:									
	$2,317,266	x					7.76%			179,820
Adjustment									$	580,637
Rounded ($000)									$	581

ROCKLAND ELECTRIC COMPANY
Statement in Support of Adjustment No. (4b)
To Distribution Operation and Maintenance Expenses
For the Twelve Months Ended September 30, 2019

To Reflect Increases In Wages And Salaries For Additional Employees

Wage and Salary Increase:

(a)	Weekly Paid Employees: Adjustment to reflect the cost of 6 additional weekly paid employees. The amounts indicated are the portion of the labor costs charged to RECO O&M expense. Additional Labor Costs charged to RECO O&M expense: October 2019 - June 2020	$	90,984
(b)	Monthly Paid Employees: Adjustment to reflect the cost of 9 additional monthly employees The amounts indicated are the portion of the labor costs charged to RECO O&M expense. Additional Labor Costs charged to RECO O&M expense: October 2019 - June 2020		40,412
Adjustment		$	131,397
Rounded ($000's)		$	131

ROCKLAND ELECTRIC COMPANY
Statement in Support of Adjustment No. (5)
To Other Operation & Maintenance Expenses
For the Twelve Months Ended September 30, 2019

To Reflect Change In Employee Health And Benefit Insurance Costs

Increase in Employee Salaries & Wages

$1,583,839	($2,375,758 x 8/12)	Per Exh. P-2, Sch. 4, Page 1
2,456,443	($2,456,443)	"
1,124,886	($2,249,772 x 6/12)	"
2,317,266		"
131,397		Per Exh. P-2, Sch. 4, Page 2
(75,593)	AMI Meter Reader Salary Savings	Per Exh. P-2, Sch. 10
$7,538,237		

Employee health and benefit insurance expense and 401K based on increase in employees:
$7,538,237 x 0.2095 = $1,579,261

Portion of Employee Health and Benefit Expense applicable to RECO:
$1,579,261 x 0.0776 = $122,551

Adjustment for Increase In Benefit Insurance Cost	$ 122,551
Rounded ($000s)	$ 123

ROCKLAND ELECTRIC COMPANY
Statement in Support of Adjustment No. (6)
To Other Operation & Maintenance Expenses
For the Twelve Months Ended September 30, 2019

To Reflect Change In Employee Pension Costs

SFAS 87 Pension Expense (January 1, 2019 - December 31, 2019)		$ 5,351,431	
Less: Capitalized / Recovered Pension Costs	(39.8%)	(2,128,227)	
Pension Expense - 12 Months Ending 12/31/19			$3,223,204
SFAS 87 Pension Expense (October 1, 2018 - September 30 2019)		5,693,902	
Less: Capitalized / Recovered Pension Costs	(39.8%)	(2,264,426)	
Pension Expense - 12 Months Ending 9/30/19			3,429,477
Adjustment for SFAS 87 Pension Cost			(206,273)
% Allocated To Distribution			91.73%
Total Adjustment for SFAS 87 Pension Cost			$ (189,214)
Rounded ($000s)			$ (189)

ROCKLAND ELECTRIC COMPANY
Statement in Support of Adjustment No. (7)
To Other Operation & Maintenance Expenses
For the Twelve Months Ended September 30, 2019

To Reflect Change In Post Retiree Expenses Other Than Pension Costs ("Opebs")

SFAS 106 OPEB Service Cost (12 Months Ended 12/31/19)		$ 844,270	
OPEB Non-Service Cost (12 Months Ended 12/31/19)		(499,670)	
Less: Capitalized / Recovered OPEB Service Cost	(39.8%)	(335,760)	
OPEB Expense - 12 Months Ending 12/31/19			$ 8,840
SFAS 106 OPEB Service Cost (12 Months Ended 9/30/19)		905,388	
OPEB Non-Service Cost (12 Months Ended 9/30/19)		(409,991)	
Less: Capitalized / Recovered OPEB Service Cost	(39.8%)	(360,067)	
OPEB Expense - 12 Months Ending 09/30/19			135,330
Adjustment for SFAS 106 OPEB Cost			(126,491)
% Allocated To Distribution (based on payroll)			91.73%
Total Adjustment for SFAS 106 OPEB Costs			$ (116,030)
Rounded ($000s)			$ (116)

ROCKLAND ELECTRIC COMPANY

Statement in Support of Adjustment No. (8)
To Operation and Maintenance Expenses
For the Twelve Months Ended September 30, 2019

To Reflect Interest On Customer Deposits

Customer Deposit Monthly Average Balance (Exhibit P-3, Schedule 10)	$	2,922,000
x 2019 Customer Deposit Rate		1.87%
Interest on Customer Deposits for the Twelve Months Ended December 31, 2019	$	54,641
Rounded ($000s)	$	55

ROCKLAND ELECTRIC COMPANY

Statement in Support of Adjustment No. (9)
To Operation and Maintenance Expenses
For the Twelve Months Ended September 30, 2019

To Reflect Rate Case Cost Amortization

Rate Case cost recovery recovered in rates (1)		$	218,750
Rate Case cost recovery reflected in rates (2)			225,000
Under recovery		$	6,250
Estimated Rate Case Costs Current Case			600,000
Total Rate Case Costs		$	606,250
Annual Amortization	$606,250 / 3		202,083
Less: Current annual rate allowance	$ 225,000 / 3		75,000
		$	127,083
Rounded ($000s)		$	127

ROCKLAND ELECTRIC COMPANY

Statement in Support of Adjustment No. (10)
To Operation and Maintenance Expenses
For the Twelve Months Ended September 30, 2019

To Eliminate Ami Customer Expenses From Test Year

Average Annual Salary for Meter Readers	$ 55,000	
x Number of Meter Reader Positions Reduced (see below)	11	
Annual Meter Reader Salaries To Be Eliminated	$ 605,000	
Allocation to RECO (EO Split)	23.99%	
Annual Meter Reader Salary To Be Eliminated in RECO		$ 145,140
x Savings Not In Test Year		52.08%
Meter Reader Adjustment to Test Year		75,593
AMI Customer Expense incurred October 2018 - Sept. 2019		18,729
Normalize -- To eliminate non-recurring expenses from Test Year		$ (94,322)
Rounded ($000's)		$ (94)

Attrition of Meter Readers	Reduction in Meter Reading Positions	Percent of Savings In Test Year	Percent of Savings Not In Test Year
- October 2018 (Actual) (a)	-	-	-
- November	1	91.67%	8.33%
- December	1	83.33%	16.67%
- January 2019	-	-	-
- February	2	66.67%	133.33%
- March (b)	1	58.33%	41.67%
- April (Forecast)	1	50.00%	50.00%
- May	1	41.67%	58.33%
- June	1	33.33%	66.67%
- July	1	25.00%	75.00%
- August	1	16.67%	83.33%
- September	1	8.33%	91.67%
Total Staffing Reductions / Weighted Average Savings	11	39.58%	52.08%

(a) Actual Staffing level as of October 2018 was 53 Meter Readers. From December 2017 - October 2018 the Company reduced its Meter Reader Staffing by 8 positions from 61 to 53 full time employees.

(b) Actual Staffing level as of March 2019 was 48 Meter Readers.

ROCKLAND ELECTRIC COMPANY

Statement in Support of Adjustment No. (11)
To Operation and Maintenance Expenses
For the Twelve Months Ended September 30, 2019

To Reflect Actual Customer Uncollectible Write-Off Experience

Year	Bad Debt Write-Offs	Billed Revenues	UB Percentage
April - December 2016	234,595	136,785,726	0.17%
2017	220,357	178,544,779	0.12%
2018	417,745	189,657,141	0.22%
January - March 2019	95,800	39,607,693	0.24%
3 Year Average	$ 322,832	$ 181,531,780	0.178%

Adjusted Revenues Twelve Months Ended September 30, 2019	$ 166,404,023
Average Customer Uncollectible Expenses	$ 295,930
Customer Uncollectible Expense Twelve Months Ended September 30, 2019	368,342
Net Adjustment	$ (72,413)
Rounded ($000s)	$ (72)

ROCKLAND ELECTRIC COMPANY

Statement in Support of Adjustment No. (12a)
To Operation and Maintenance Expenses
For the Twelve Months Ended September 30, 2019

To Reflect Adjustment To Operations

Danger Tree Program: To Address Emerald Ash Borer and Other Dead / Diseased Trouble Spots	$	500,000
Total	$	500,000
Rounded ($000s)	$	500

ROCKLAND ELECTRIC COMPANY

Statement in Support of Adjustment No. (12b)
To Operation and Maintenance Expenses
For the Twelve Months Ended September 30, 2019

To Increase Annual Funding For The Storm Reserve

Storm Description	Start Date	Deferred Amount
2014 Storm #9 (Thanksgiving)	11/26/2014	$ 143,377
2017 Storm #2	2/13/2017	306,430
2017 Storm #8	10/29/2017	253,885
2018 Storm #1 (Riley)	3/2/2018	1,460,453
2018 Storm #2 (Quinn)	3/7/2018	10,066,863
2018 Storm #4	5/15/2018	4,813,112
2019 Storm #2	2/24/2019	484,861
Five Year total of Deferred Storm Costs		$ 17,528,981
Less: 2018 Storm #2 (Quinn)		(10,066,863)
Five Year total of Deferred Storm Costs excluding 3/7/18 Storm		$ 7,498,820
5 Year Average Excluding 3/7/18 Storm		$ 1,499,764
Current Storm Allowance		750,000
Increase to Current Allowance		$ 749,764
Rounded ($000s)		$ 750

ROCKLAND ELECTRIC COMPANY

Statement in Support of Adjustment No. (13)
To Operation and Maintenance Expenses
For the Twelve Months Ended September 30, 2019

To Equalize Return Component Of Intercompany Billings

	Joint Operating Agreement Rents			
Return on Equity	Customer & Distribution	A&G @ 91.73%	Total	Rounded ($000s)
13.00% **(a)**				
10.00%	$ (252,378)	(197,532)	(449,910)	$ (450)

(a) The return on equity embedded in JOA billings between
RECO and O&R

ROCKLAND ELECTRIC COMPANY

Statement in Support of Adjustment No. 14 (a)
To Operation and Maintenance Expenses
For the Twelve Months Ended September 30, 2019

To Reflect Storm Cost Amortizations In Rate Year

Storm Description	Start Date	Deferred Amount	
2014 Storm #9 (Thanksgiving)	11/26/2014	$ 143,377	
2017 Storm #2	2/13/2017	306,430	
2017 Storm #8	10/29/2017	253,885	
2018 Storm #1 (Riley)	3/2/2018	1,460,453	
2018 Storm #2 (Quinn)	3/7/2018	10,066,863	
2018 Storm #4	5/15/2018	4,813,112	
2019 Storm #2	2/24/2019	484,861	
Total Deferred Storm Costs			$ 17,528,981

Recovery for Deferred Storm Costs ($750,000 annually)	Months		
Opening Balance in Storm Reserve		$ (342,936)	
August - December 2014	5	(312,500)	
January - December 2015	12	(750,000)	
January - December 2016	12	(750,000)	
January - December 2017	12	(750,000)	
January - December 2018	12	(750,000)	
January - September 2019	9	(562,500)	
	62		
Five Year Funding for Storms			$ (4,217,936)
Deferred Storm Cost Balance 9/30/2019			$ 13,311,045
Recovery Period (Years)			3
Adjustment			$ 4,437,015
Rounded ($000's)			$ 4,437

ROCKLAND ELECTRIC COMPANY

Statement in Support of Adjustment No. 14 (b)
To Operation and Maintenance Expenses
For the Twelve Months Ended September 30, 2019

To reflect Managment Audit amortizations in Rate Year

Deferred Management Audit Fees	$	655,200
Recovery Period (Years)		3
Adjustment	$	218,400
Rounded ($000's)	$	218

ROCKLAND ELECTRIC COMPANY

Statement in Support of Adjustment No. (15)
To Operation and Maintenance Expenses
For the Twelve Months Ended September 30, 2019

To Eliminate Regulatory Amortization From Test Year

		Annual Amounts
Previously authorized amortizations - refunds (1)	$	18,000
Total Adjustment for Expiring amortizations	$	18,000
Rounded (&000s)	$	18

(1) Annual amortization of net deferred credits will be completed February 28, 2020

ROCKLAND ELECTRIC COMPANY

Statement in Support of Adjustment No. (16)
To Depreciation Expense
For the Twelve Months Ended September 30, 2019

To Annualize Depreciation And Reflect Revised Depreciation Rates

Annualization of Book Depreciation at Current Rates		
Annualized Book Depreciation at Current Rates		$ 7,240,878
Book Depreciation Included in the Test Year Ended September 30, 2019		7,041,647
Annualization Adjustment		$ 199,231
Annualization of Book Depreciation at Proposed Rates		
Distribution Plant at September 30, 2019 (Per Exhibit P-3 Summary)		$370,377,402
Composite Proposed Depreciation Rate (excludes Transmission)	2.132%	
Composite Existing Depreciation Rate (excludes Transmission)	1.955%	
Net Change resulting from proposed depreciation rates		0.177%
Annualization Adjustment		$ 655,568
Total		854,799
Rounded ($000s)		$ 855

ROCKLAND ELECTRIC COMPANY

Statement in Support of Adjustment No. (17)
To Depreciation Expense
For the Twelve Months Ended September 30, 2019

Adjustment to Annualize Depreciation and Reflect Revised Depreciation Rates:

Post Test Year Additions -- Book Depreciation at Current Rates		
Post Test Year Plant Additions (Per Exhibit P-3, Schedule 1)	$11,830,251	
Post Test Year Plant Retirements (Per Exhibit P-3, Schedule 1)	2,188,700	
Net Change in Plant		$9,641,551
Composite Existing Depreciation Rate (excludes Transmission)		1.955%
Annualization Adjustment		$188,492
Annualization of Book Depreciation at Proposed Rates		
Distribution Plant at December 31, 2016 (Per Exhibit P-3 Summary)		$9,641,551
Composite Proposed Depreciation Rate (excludes Transmission)	2.132%	
Composite Existing Depreciation Rate (excludes Transmission)	1.955%	
Net Change resulting from proposed depreciation rates		0.177%
Annualization Adjustment		$17,066
Total		$205,558
Rounded ($000's)		$206

ROCKLAND ELECTRIC COMPANY

Statement in Support of Adjustment No. (18a)
To Depreciation Expense
For the Twelve Months Ended September 30, 2019

Adjustment to Deprecation Expense for Unallocated
Reserve Balances to be fully recovered by 2/28/2020

Deferred Net Salvage Balances @ September 30, 2019		
RE - E- 399080 - UNALLOC RES Net Salvage 2015	$ 120,120	
RE - E- 399090 - UNALLOC RES Net Salvage 2017	72,840	
Deferred Balance @ 9/30/2019	`	$ 192,960
Amortization of Post Test Year Balance		
RE - E- 399080 - UNALLOC RES Net Salvage 2015	(96,088)	
RE - E- 399090 - UNALLOC RES Net Salvage 2017	(53,782)	
Amortization (October 1, 2018 - January 31, 2019)		(149,870)
Deferred Net Salvage Balances @ January 31, 2020		
RE - E- 399080 - UNALLOC RES Net Salvage 2015	$ 24,032	
RE - E- 399090 - UNALLOC RES Net Salvage 2017	19,058	
Deferred Balance @ 1/31/2020		$ 43,090
Annual amortization of 1/31/2020 balance over 3 Years		$ 14,363
Annual amortization included in base rates		(463,056)
Adjustment		$ (448,693)
Rounded		$ (449)
Continuing Deferred Net Salvage Balance @ September 30, 2019		
RE - E- 399100 - UNALLOC RES Net Salvage 2017		$ (8,096,692)
Annual amortization expense for remaining balance over 12.4 Years		$ 652,080
Adjustment		$ -
Rounded		$ -

ROCKLAND ELECTRIC COMPANY
Statement in Support of Adjustment No. (18b)
To Depreciation Expense
For the Twelve Months Ended September 30, 2019

Difference in Actual Spending from January 1, 2017 thru September 30, 2019 versus Rate Allowance

Actual Net Salvage Charged: 12 Months Ended December 31, 2017	$ 2,916,496		
12 Months Ended December 31, 2018	1,386,865		
January 1, 2019 - March 31, 2019	405,623		
Estimated Net Salvage Costs: April 1, 2019 - September 30, 2019 (1)	512,202	$ 5,221,186	
Rate Allowance: January 1, 2017 - February 28, 2017 ($68,400 X 2 months)	136,800		
March 1, 2017 - September 30, 2019 ($85,367 X 31 months)	2,646,377	2,783,177	
Unrecovered Net Salvage		$ 2,438,009	
Difference Amortized over 3 Years			$812,670

(1) To be updated for actual spending through September 30, 2019 - estimate based on current rate allowance ($1,024,404 / 2)

Adjustment to update provision for salvage cost, based on a cumulative average of actual from January 1, 2017 through September 30, 2019 (1).

Net Salvage Charges January 1, 2017 - September 30, 2019 (see above)	$ 5,221,186		
Less: Major Non Recurring 2017 Salvage Charges:			
Removal of Grand Avenue Substation	(907,983)		
Removal of RECO portion Lines 73/74 - Ford Substation to Airmont Substation	(555,727)		
Removal of Old Montvale Substation Switch House	(239,342)		
Net Salvage Charges excluding old Summit Avenue Substation	$ 3,518,134		
Average Monthly Net Salvage Charges ($4,520,230 / 33 months)	$ 106,610		
Average Annual Net Salvage Charges		$ 1,279,321	
Less: Annual Net Removal Costs Allowed (Case ER16050428)		1,024,404	
Additional Net Removal Costs			$254,917
Total Additional Cost of Removal Requested			$1,067,587
Rounded ($000's)			$1,068

ROCKLAND ELECTRIC COMPANY

Statement in Support of Adjustment No. (19)
To Depreciation Expense
For the Twelve Months Ended September 30, 2019

To Amortize Meters Retired As Part Of Ami Project

Meter Depreciation Reserve Debit Balance at September 30, 2019

$000's			
370100 E Meters - EM Purchases	$ 1,277		
370110 E Meters - SS Purchases	1,560		
370200 E Meters - EM Installs	191		
370210 E Meters - SS Installations	2,150		
Total		$	5,178
Recovery Period (Years)			15
Adjustment		$	345.2
Rounded		$	345

ROCKLAND ELECTRIC COMPANY

Statement in Support of Adjustment No. (20)
To Taxes Other Than Income Taxes
For the Twelve Months Ended September 30, 2019

Adjustment to Reflect Increases in Payroll Taxes:

Payroll increase prior to allocation to electric operations:

$1,583,839	($2,375,758 x 8/12)	Per Exh. P-2, Sch. 4, Page 1
2,456,443	($2,456,443)	"
1,124,886	($2,249,772 x 6/12)	"
2,317,266	($2,317,266)	"
131,397		Per Exh. P-2, Sch. 4, Page 2
(75,593)		Per Exh. P-2, Sch. 10
$7,538,237		

Effective Payroll Tax Rate:

7.74%

Payroll tax increase prior to allocation to electric operations:

$7,538,237 x 0.0774 = $583,460

Portion of Payroll Taxes applicable to Operation and Maintenance Payroll	$583,460	x	0.0776	=	$45,276
	Rounded ($000's)				$45

ROCKLAND ELECTRIC COMPANY

Calculation of State CBT
For the Twelve Months Ended September 30, 2019
($000s)

	Transmission & Distribution 12 Mos. Ended 9/30/2019	Transmission 12 Mos. Ended 9/30/2019	Electric Distribution 12 Mos. Ended 9/30/2019
OPERATING INCOME BEFORE INCOME TAXES	7,467	(1,015)	$8,482
LESS: INTEREST EXPENSE	6,694	435	6,259
BOOK INCOME BEFORE INCOME TAXES	773	(1,450)	2,223
Permanent Items	-	-	-
Total Permanent Items	-	-	-
Temporary Items			
Repair Allowance	(6,368)	(532)	(5,836)
Book / Accelerated Tax Depreciation	(6,858)	(573)	(6,286)
MSC Plant Deduction	(2,910)	(243)	(2,667)
Single Asset Deduction	(2,556)	(213)	(2,343)
Materials and Supplies Deduction	(595)	(50)	(545)
Cost of Removal Normalized State	(804)	(67)	(737)
Capitalized Overheads	(170)	(14)	(156)
AFUDC Equity	(298)	(25)	(273)
AFUDC Borrowed Funds	(174)	(15)	(159)
Capitalized Interest	357	30	327
Contributions in Aid of Construction	(70)	(6)	(64)
Deferred Purchased Power	2,596	-	2,596
Bad Debt Expense	368	-	368
Rate Case Cost	-	-	-
Amortization of Rate Case Cost	75	-	75
Amortization of Regulatory Deferrals	18	-	18
Deferred Storm Charges	-	-	-
Storm Reserve Accruals	1,500	-	1,500
Amortization of retired Meters	-	-	-
Federal Tax Reform - Transition Period	-	-	-
Total for Temporary Items	(15,889)	(1,707)	(14,182)
Flow-thru Items	-	-	-
Total for Flow-thru Items	-	-	-
Taxable Income or (Loss)	(15,116)	(3,157)	(11,959)
Current SIT @ 9%	(1,360)	(284)	(1,076)
Deferred SIT	1,430	154	1,276
Total SIT	$ 70	$ (130)	$ 200

ROCKLAND ELECTRIC COMPANY

Calculation of Electric Distribution - State CBT

For the Twelve Months Ended September 30, 2019

($000s)

	Distribution 12 Mos. Ended 9/30/2019	Adjustments Reference	Adjustments Amount	12 Mos. Ended 9/30/2019 As Adjusted	Proposed Rate Change	12 Mos. Ended 9/30/2019 As Adjusted For Add'l Revenue
OPERATING INCOME BEFORE INCOME TAXES	$8,482		(8,202)	$280	19,870	$20,149
LESS: INTEREST EXPENSE	6,259	(23)	$197	6,456	-	6,456
BOOK INCOME BEFORE INCOME TAXES	2,223		(8,399)	(6,176)	19,870	13,693
Permanent Items	-			-		-
Total Permanent Items	-			-		-
Temporary Items						
Repair Allowance	(5,836)			(5,836)		(5,836)
Book / Accelerated Tax Depreciation	(6,286)			(6,286)		(6,286)
MSC Plant Deduction	(2,667)			(2,667)		(2,667)
Single Asset Deduction	(2,343)			(2,343)		(2,343)
Materials and Supplies Deduction	(545)			(545)		(545)
Cost of Removal Normalized State	(737)			(737)		(737)
Capitalized Overheads	(156)			(156)		(156)
AFUDC Equity	(273)		273	-		-
AFUDC Borrowed Funds	(159)		159	-		-
Capitalized Interest	327		(327)	-		-
Contributions in Aid of Construction	(64)			(64)		(64)
Deferred Purchased Power	2,596			2,596		2,596
Bad Debt Expense	368	(11)	(368)	-	-	-
Rate Case Cost	-	(9)	(600)	(600)		(600)
Amortization of Rate Case Cost	75	(9)	127	202		202
Amortization of Regulatory Deferrals	18	(15)	(18)	-		-
Deferred Storm Charges	-		-	-		-
Storm Reserve Accruals	1,500	(12)(14)	5,187	6,687		6,687
Amortization of retired Meters	-	(19)	345	345		345
Federal Tax Reform - Transition Period	-			-		-
Total for Temporary Items	(14,182)		4,778	(9,403)	-	(9,403)
Flow-thru Items	-		-	-		-
Total for Flow-thru Items	-		-	-		-
Taxable Income or (Loss)	(11,959)		(3,620)	(15,579)	19,870	4,290
Current SIT @ 9%	(1,076)		(326)	(1,402)	1,788	386
Deferred SIT	1,276		(430)	846	-	846
Total SIT	$ 200		$ (756)	$ (556)	$ 1,788	$ 1,232

ROCKLAND ELECTRIC COMPANY
Calculation of Federal Income Tax
For the Twelve Months Ended September 30, 2019
($000s)

	Transmission & Distribution 12 Mos. Ended 9/30/2019	Transmission 12 Mos. Ended 9/30/2019	Electric Distribution 12 Mos. Ended 9/30/2019
OPERATING INCOME BEFORE INCOME TAXES	$ 7,467	$ (1,015)	$ 8,482
INTEREST EXPENSE	6,694	435	6,259
BOOK INCOME BEFORE FIT	773	(1,450)	2,223
PERMANENT ITEMS:			
TOTAL PERMANENT ITEMS			
Temporary Items			
Repair Allowance	(6,281)	(524)	(5,756)
MSC Plant Deduction	(2,910)	(243)	(2,667)
Accelerated Tax Depreciation	(2,713)	(227)	(2,486)
Capitalized Overheads	(170)	(14)	(156)
AFUDC Borrowed Funds	(187)	(16)	(171)
Capitalized Interest	399	33	366
Contributions in Aid of Construction	(215)	-	(215)
Materials and Supplies Deduction	(595)	-	(595)
Deferred Purchased Power	2,596	-	2,596
Amortization of Rate Case Cost	75	-	75
Amortization of Regulatory Deferrals	18	-	18
Deferred Storm Charges	-	-	-
Storm Reserve Accruals	1,500	-	1,500
Amortization of retired Meters	-	-	-
Federal Tax Reform - Transition Period	-	-	-
Total for Temporary Items	(8,480)	(990)	(7,490)
Flow-thru Items			
Bad Debt Accrual	368	-	368
AFUDC Equity Funds	(298)	(25)	(273)
Capitalized Overheads	22	-	22
Accelerated Tax Depreciation	39	-	39
Removal cost included in depreciation accrual	1,784	-	1,784
Cost of Removal	(804)	(67)	(737)
Total for Flow-thru Items	1,111	(92)	1,203
Taxable Income Before Deductions	(6,597)	(2,532)	(4,065)
Less : State Tax Deduction - Current	(1,360)	(284)	(1,076)
Taxable Income or (Loss)	(5,237)	(2,248)	(2,988)
Current FIT @ 21%	**(1,100)**	**(472)**	**(628)**
Deferred Federal Tax Expense-Plant	2,661	208	2,453
Deferred Federal Tax Expense-Non Plant	(880)	-	(880)
	(300)	(32)	(268)
Total Deferred FIT	**1,481**	**176**	**1,305**
Amortization of Excess Deferred Income Taxes:			
Federal Tax Rate Change - Protected Property	**(343)**	**-**	**(343)**
Federal Tax Rate Change - Non-Property	**(2,545)**	**-**	**(2,545)**
NJ Corp Tax Offset to Federal Non-Property Rate Changes	**-**	**-**	**-**
Investment tax credit - FERC 255 / Natural Acct 23010	**(39)**	(3)	**(36)**
Total FIT	**$ (2,546)**	**$ (300)**	**$ (2,246)**

ROCKLAND ELECTRIC COMPANY
Calculation of Electric Distribution Federal Income Tax
For the Twelve Months Ended September 30, 2019
($000s)

	Distribution 12 Mos. Ended 9/30/2019	Adjustments Reference	Adjustments Amount	12 Mos. Ended 9/30/2019 As Adjusted	Proposed Rate Change	12 Mos. Ended 9/30/2019 As Adjusted For Add'l Revenue
	(1)	(2)	(3)	(4) = (1+3)	(5)	(6)
OPERATING INCOME BEFORE INCOME TAXES	$8,482		(8,202)	$280	19,870	$20,149
INTEREST EXPENSE	$6,259	(23)	197	6,456	-	6,456
BOOK INCOME BEFORE FIT	2,223		(8,399)	(6,176)	19,870	13,693
PERMANENT ITEMS:	-		-	-		-
TOTAL PERMANENT ITEMS	-		-	-		-
Temporary Items						
Repair Allowance	(5,756)		-	(5,756)		(5,756)
MSC Plant Deduction	(2,667)		-	(2,667)		(2,667)
Accelerated Tax Depreciation	(2,486)		-	(2,486)		(2,486)
Capitalized Overheads	(156)		-	(156)		(156)
AFUDC Borrowed Funds	(171)		171	-		-
Capitalized Interest	366		(366)	-		-
Contributions in Aid of Construction	(215)		-	(215)		(215)
Materials and Supplies Deduction	(595)		1	(594)		(594)
Deferred Purchased Power	2,596		2	2,598		2,598
Amortization of Rate Case Cost	75	(9)	127	202		202
Amortization of Regulatory Deferrals	18	(15)	(18)	-		-
Deferred Storm Charges	-		-	-		-
Storm Reserve Accruals	1,500	(12)(14)	5,187	6,687		6,687
Amortization of retired Meters	-	(19)	345	345		345
Federal Tax Reform - Transition Period	-		-	-		-
Total for Temporary Items	(7,490)		5,449	(2,041)	-	(2,041)
Flow-thru Items						
Bad Debt Accrual	368	(11)	(368)	-	-	-
AFUDC Equity Funds	(273)		273	-		-
Capitalized Overheads	22			22		22
Accelerated Tax Depreciation	39			39		39
Removal cost included in depreciation accrual	1,784			1,784		1,784
Cost of Removal	(737)		-	(737)		(737)
Total for Flow-thru Items	1,203		(95)	1,108	-	1,108
Taxable Income Before Deductions	(4,065)		(3,045)	(7,109)	19,870	12,760
Less : State Tax Deduction	(1,076)		(326)	(1,402)	1,788	386
Taxable Income or (Loss)	(2,988)		(2,719)	(5,707)	18,081	12,374
Current FIT @ 21%	(628)		(571)	(1,199)	3,797	2,599
Deferred Federal Tax Expense-Plant	2,453		41	2,493	-	2,493
Deferred Federal Tax Expense-Non Plant	(880)		(1,095)	(2,242)	-	(2,242)
	(268)					
Total Deferred FIT	1,305		(1,054)	251	-	251
Amortization of Excess Deferred Income Taxes:						
Federal Tax Rate Change - Protected Property	(343)		-	(343)	-	(343)
Federal Tax Rate Change - Non-Property	(2,545)		-	(2,545)	-	(2,545)
NJ Corp Tax Offset to Federal Non-Property Rate Changes	-		-	-	-	-
Investment tax credit - FERC 255 / Natural Acct 23010	(36)		-	(36)	-	(36)
Total FIT	$ (2,246)		$ (1,625)	$ (3,871)	$ 3,797	$ (74)

ROCKLAND ELECTRIC COMPANY
CALCULATION OF INTEREST SYNCHRONIZATION
For the Twelve Months Ended September 30, 2019
($000s)

INTEREST SYNCHRONIZATION	Transmission & Distribution 12 Mos. Ended 9/30/2019	Transmission 12 Mos. Ended 9/30/2019	Electric Distribution 12 Mos. Ended 9/30/2019	Adjustment	12 Mos. Ended 9/30/2019 As Adjusted	Proposed Rate Change	12 Mos. Ended 9/30/2019 As Adjusted For Add'l Revenue
RATE BASE	$260,465	$16,921	$243,544	$ 7,654	$251,198		$251,198
TOTAL WEIGHTED AVG COST OF DEBT	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%	2.57%
INTEREST SYNCHRONIZATION LEVEL	$6,694	$435	$6,259	$197	$6,456	$0	$6,456

ROCKLAND ELECTRIC COMPANY
INDEX OF SCHEDULES

ELECTRIC RATE BASE WITH SUPPORTING SCHEDULES

Schedule	Title of Schedules	Witness
Summary	Electric Rate Base	Accounting Panel
1	Electric Plant in Service	"
2	Electric Plant Held for Future Use	"
3	Non-Interest Bearing Construction Work in Progress	"
4	Accumulated Provision for Depreciation of Electric Plant in Service	"
5	Accumulated Provision for Depreciation of Electric Plant Held for Future Use	"
6	Working Capital Requirements	"
7	Deferred Regulatory Assets/Liabilities	"
8	Storm Reserve	"
9	Net Pension/OPEBs	
10	Customer Deposits	"
10	Customer Advances for Construction	
11	Accumulated Deferred Income Taxes	"
12	Major Plant Additions	Electric Infrastructure Panel
13	Consolidated Tax Adjustment	Accounting Panel

ROCKLAND ELECTRIC COMPANY
ELECTRIC RATE BASE
AT SEPTEMBER 30, 2019
($ 000s)

	Actual Balance at 3/31/19	Less: Transmission 3/31/19	Distribution Balance at 3/31/19	Adjustments	As Adjusted	Schedule No.
UTILITY PLANT						
Electric Plant in Service	$ 404,120	$ 33,742	$ 370,377	$ 9,642	$ 380,019	1
Electric Plant Held for Future Use	209	-	209	-	209	2
Construction Work in Progress Not Taking Interest	4,569	380	4,189	-	4,189	3
TOTAL UTILITY PLANT	408,897	34,122	374,775	9,642	384,417	
UTILITY PLANT RESERVES						
Accum. Provision for Depreciation of Electric Plant in Service	(88,495)	(11,970)	(76,525)	(1,917)	(78,442)	4
Accum. Provision for Depreciation of Electric Plant Held for Future Use	-	-	-	-	-	5
TOTAL UTILITY PLANT RESERVES	(88,495)	(11,970)	(76,525)	(1,917)	(78,442)	
NET PLANT	320,402	22,152	298,250	7,724	305,975	
ADDITIONS TO NET PLANT						
Working Capital Requirements	13,678	1,343	12,335	-	12,335	6
Deferred Regulatory Balances	569	-	569	-	569	7
Storm Reserve	9,569	-	9,569	-	9,569	8
TOTAL ADDITIONS TO NET PLANT	23,816	1,343	22,473	-	22,473	
DEDUCTIONS FROM NET PLANT						
Net Pension/OPEB Liability	-	-	-	-	-	9
Customer Deposits	2,922	-	2,922	-	2,922	10
Customer Advances for Construction	1,804	-	1,804	-	1,804	10
Accum. Deferred Income Tax	79,003	6,572	72,431	70	72,501	11
Consolidated Tax Adjustment	25	2	23	-	23	13
TOTAL DEDUCTIONS FROM NET PLANT	83,754	6,574	77,180	70	77,250	
ELECTRIC RATE BASE	$ 260,465	$ 16,921	$ 243,544	$ 7,654	$ 251,198	

ROCKLAND ELECTRIC COMPANY
ELECTRIC PLANT IN SERVICE
AT SEPTEMBER 30, 2019
($ 000s)

	Total T&D	Transmission	Distribution
Beginning Balance at March 31, 2019			
Direct	$ 384,900	$ 32,020	$ 352,879
General Plant (Allocated)	10,249	853	9,396
Beginning Balance at March 31, 2019	395,149	32,873	362,276
Additions (April to Sept 2019)			
Direct	9,651	852	8,800
General Plant (Allocated)	1,299	108	1,191
Total Additions	10,950	960	9,991
Retirements (April to Sept 2019)			
Direct	1,980	91	1,889
General Plant (Allocated)	-	-	-
Total Retirements	1,980	91	1,889
Ending Balance at September 30, 2019	$ 404,120	$ 33,742	$ 370,377
Post Test Year Adjustments (October 2019 to March 2020)			
Additions			
Direct	11,724	376	11,348
General Plant (Allocated)	526	44	482
Total Additions	12,251	420	11,830
Retirements			
Direct	1,938	91	1,848
General Plant (Allocated)	372	31	341
Total Retirements	2,310	121	2,189
Total Adjustments	9,941	299	9,642
Total As Adjusted	$ 414,060	$ 34,041	$ 380,019

Exhibit P-3
Schedule 2

ROCKLAND ELECTRIC COMPANY
ELECTRIC PLANT HELD FOR FUTURE USE
AT SEPTEMBER 30, 2019
($ 000s)

	Total T&D	Transmission	Distribution
Beginning Balance at March 31, 2019	$ 209	$ -	$ 209
Additions (April to Sept 2019)	-	-	-
Ending Balance at September 30, 2019	$ 209	$ -	$ 209

ROCKLAND ELECTRIC COMPANY
NON-INTEREST BEARING CONSTRUCTION WORK IN PROGRESS
AT SEPTEMBER 30, 2019
($ 000s)

Month		Amount
Oct-18	Actual	$ 5,107
Nov-18	Actual	5,448
Dec-18	Actual	5,147
Jan-19	Actual	6,281
Feb-19	Actual	6,740
Mar-19	Actual	6,974
Apr-19	Forecast	2,242
May-19	Forecast	2,414
Jun-19	Forecast	2,277
Jul-19	Forecast	3,555
Aug-19	Forecast	3,683
Sep-19	Forecast	4,956
	Twelve Month Total	$ 54,826
	Monthly Average	$ 4,569
	Ratio of Distribution Plant to total T&D Plant	91.68%
	Distribution Balance	$ 4,189

ROCKLAND ELECTRIC COMPANY
ACCUMULATED PROVISION FOR DEPRECIATION
ELECTRIC PLANT
AT SEPTEMBER 30, 2019
($ 000s)

	Total T&D	Transmission	Distribution
Beginning Balance at March 31, 2019	$ (85,951)	$ (11,534)	$ (74,417)
Additions			
Direct	(3,501)	(390)	(3,111)
General Plant (Allocated)	(1,023)	(137)	(886)
Total Additions	(4,524)	(527)	(3,997)
Retirements			
Direct	(1,980)	(91)	(1,889)
General Plant (Allocated)	-	-	-
Total Retirements	(1,980)	(91)	(1,889)
Ending Balance at September 30, 2019	$ (88,495)	$ (11,970)	$ (76,525)
Post Test Year Adjustments			
Additions			
Direct	(3,618)	(388)	(3,230)
General Plant (Allocated)	(990)	(133)	(857)
Total Additions	(4,608)	(521)	(4,087)
Retirements			
Direct	(1,938)	(90)	(1,848)
General Plant (Allocated)	(372)	(50)	(322)
Total Retirements	(2,310)	(140)	(2,170)
Total Adjustments	(2,298)	(381)	(1,917)
Total As Adjusted	$ (90,793)	$ (12,351)	$ (78,442)

ROCKLAND ELECTRIC COMPANY
ACCUMULATED PROVISION FOR DEPRECIATION
ELECTRIC PLANT HELD FOR FUTURE USE
AT SEPTEMBER 30, 2019
($ 000s)

	Total T&D	Transmission	Distribution
Beginning Balance at March 31, 2019	$ -	$ -	$ -
Adjustments	-	-	-
Ending Balance at September 30, 2019	$ -	$ -	$ -

ROCKLAND ELECTRIC COMPANY
ELECTRIC WORKING CAPITAL REQUIREMENTS
AT SEPTEMBER 30, 2019
($ 000s)

Description	T&D Total	Transmission Allocation	Distribution Allocation
Net Cash Working Capital	$ 7,442	$ 938	$ 6,504
Prepayments	2,705	111	2,594
Materials and Supplies	3,531	294	3,237
Total	$ 13,678	$ 1,343	$ 12,335

ROCKLAND ELECTRIC COMPANY
SUMMARY OF CASH WORKING CAPITAL ALLOWANCE
REQUIRED FOR COST OF SERVICE
TWELVE MONTHS ENDED SEPTEMBER 30, 2019

	Reference	T&D Amount	Distribution Amount	(Lead) / Lag Days	T&D Dollar Days	Distribution Dollar Days
Revenue Recovery	Sch. 1	$ 163,553,614	$ 146,812,921	40.4	$ 6,605,517,194	$ 5,929,402,920
Sales tax	Sch. 1	9,813,217	8,808,775	40.4	396,331,032	355,764,175
		173,366,830	155,621,696		7,001,848,226	6,285,167,095
Purchased Power Expenses:						
BGS	Sch. 2	77,019,751	77,019,751	35.1	2,705,318,764	2,705,318,764
O&R	Sch. 2	18,181,494	6,010,001	45.0	818,167,234	270,450,054
Deferred Purchased Power Expense	Sch. 8	(2,596,385)	(2,596,385)	-	-	-
Salaries & Wages	Sch. 3	16,266,262	14,348,060	7.7	124,685,409	109,981,854
Pensions	Sch. 4	3,223,204	2,956,645	30.0	96,696,119	88,699,350
OPEBs	Sch. 5	8,840	8,109	79.5	702,752	644,635
Joint Operating Expense	Sch. 6	6,888,068	6,063,191	45.0	309,963,060	272,843,577
Uncollectible Accounts Accrual	Sch. 7	295,930	295,930	40.4	11,951,845	11,951,845
Material & Supplies issues	Sch. 8	447,122	441,327	-	-	-
Other O&M	Sch. 9	21,048,401	25,380,435	36.0	757,825,450	913,795,726
Amortizations:	Sch. 8					
Storm Reserve		4,437,015	4,437,015	-	-	-
Rate Case Costs		202,083	202,083	-	-	-
Management Audit		218,400	218,400	-	-	-
Depreciation & Amortization	Sch. 8	8,688,635	9,945,635	-	-	-
Taxes Other Than Income Taxes						
Payroll Taxes	Sch. 10	1,125,743	1,170,743	6.7	7,503,389	7,803,327
Property Taxes	Sch. 8	632,354	632,354	-	-	-
New Jersey Sales Tax (UTUA)	Sch. 11	9,813,217	8,808,775	(51.3)	(502,927,362)	(451,449,732)
Income Taxes:						
Federal Income Tax	Sch. 12	(1,099,672)	(1,198,515)	37.5	(41,237,693)	(44,944,310)
Deferred Federal Income Tax	Sch. 8	1,480,582	250,897	-	-	-
Amortization of EDFIT	Sch. 8	(2,887,913)	(2,887,913)	-	-	-
Investment Tax Credit	Sch. 8	(39,000)	(35,744)	-	-	-
Corporate Business Tax (State)	Sch. 13	69,548	(555,854)	(46.8)	(3,251,375)	25,986,194
Return on Invested Capital	Sch. 8	9,943,151	4,706,757	-	-	-
Total Requirement		$ 173,366,830	$ 155,621,696	25.1	4,285,397,592	3,911,081,285
		$ -	$ -			
Net Lag				15.3	$ 2,716,450,634	$ 2,374,085,810
Net Requirement (Net Lag / 365)					**$ 7,442,331**	**$ 6,504,345**

ROCKLAND ELECTRIC COMPANY
ELECTRIC WORKING CAPITAL REQUIREMENTS
PREPAYMENTS
AT SEPTEMBER 30, 2019
($ 000s)

Month		Property Taxes	State Sales Taxes	BPU Assessment	Total
Oct-18	Actual	1,635	695	78	$ 2,408
Nov-18	(Actual)	1,581	(122)	39	1,498
Dec-18	(Actual)	1,607	(895)	-	712
Jan-19	(Actual)	1,712	(941)	(39)	732
Feb-19	(Actual)	1,659	(840)	431	1,250
Mar-19	(Actual)	1,605	(838)	388	1,155
Apr-19	Forecast	758	(865)	312	205
May-19	Forecast	706	4,814	273	5,793
Jun-19	Forecast	1,043	4,524	234	5,801
Jul-19	Forecast	1,116	4,289	195	5,600
Aug-19	Forecast	1,100	2,832	156	4,088
Sep-19	Forecast	1,527	1,576	117	3,220
	Twelve Month Total	$ 16,049	$ 14,229	$ 2,184	$ 32,462
	Monthly Average	$ 1,337	$ 1,186	$ 182	$ 2,705
Ratio of distribution plant to total T&D plant		91.68%	N/A	N/A	
Distribution Balance		$ 1,226	$ 1,186	$ 182	$ 2,594

ROCKLAND ELECTRIC COMPANY
ELECTRIC WORKING CAPITAL REQUIREMENTS
MATERIALS AND SUPPLIES
AT SEPTEMBER 30, 2019
($ 000s)

Month		General Plant In Stock	Common Plant In Stock	Total
Oct-18	(Actual)	3,579	-	$ 3,579
Nov-18	(Actual)	3,455	-	3,455
Dec-18	(Actual)	3,389	-	3,389
Jan-19	(Actual)	3,402	-	3,402
Feb-19	(Actual)	3,477	-	3,477
Mar-19	(Actual)	3,488	-	3,488
Apr-19	Forecast	3,578	-	3,578
May-19	Forecast	3,578	-	3,578
Jun-19	Forecast	3,627	-	3,627
Jul-19	Forecast	3,557	-	3,557
Aug-19	Forecast	3,590	-	3,590
Sep-19	Forecast	3,655	-	3,655
	Twelve Month Total	$ 42,375	$ -	$ 42,375
	Monthly Average	$ 3,531	$ -	$ 3,531
Ratio of distribution plant to total T&D plant		91.68%	91.68%	91.68%
Distribution Balance		$ 3,237	$ -	$ 3,237

ROCKLAND ELECTRIC COMPANY
DEFERRED REGULATORY BALANCES
AT SEPTEMBER 30, 2019
($ 000s)

Deferred Regulatory Balances	Deferred Management Audit Expenditures Account 15157	Deferred Rate Case Costs Account 15171	Amortization of Expiring Deferrals Account 24478	Federal Tax Reform Protected Transition Balance Account 24525	Total
Beginning Balance at March 31, 2019	$ 655	$ 134	$ (17)	$ (361)	$ 412
Plus: Spending through September 2019	-	534	-	(127)	407
Less: Amort. April to Sept 2019	-	(38)	9	-	(29)
Ending Balance at September 30, 2019	655	631	(8)	(488)	$ 791
Less Deferred Taxes	(184)	(177)	2	137	$ (222)
Ending Balance at September 30, 2019	$ 471	$ 454	$ (6)	$ (351)	$ 569

ROCKLAND ELECTRIC COMPANY
STORM RESERVE
AT SEPTEMBER 30, 2019
($ 000s)

Storm Reserve (Acct 21947/15186)	
Beginning Balance at March 31, 2019	$ 13,686.0
Accruals (April to Sept 2019)	(375.0)
Projected Storm Charges (April to Sept 2019)	-
Ending Balance at September 30, 2019	$ 13,311.0
Less Deferred Taxes	(3,742)
Net Storm Reserve	$ 9,569

ROCKLAND ELECTRIC COMPANY
NET PENSION/OPEB ACCRUED LIABILITY
AT SEPTEMBER 30, 2019
($ 000s)

	April to Sept 20
OPEB Accrued Liability:	
Beginning Balance at March 31, 2019	$ -
Add: April to Sept 2	
FAS 106 Expense	
Current Accruals	172
Pay-As-You-Go	-
Amounts Funded	(172)
Subtotal	-
Ending Balance at September 30, 2019	$ -
Pension Deferral/Liability:	
Beginning Balance at March 31, 2019	$ -
Add: April to Sept 2	
FAS 106 Expense	
Current Accruals	2,676
Amounts Funded	(2,676)
Subtotal	-
Ending Balance at September 30, 2019	$ -
Net Pension/OPEB Liability Before Income Tax	$ -
Less Federal & State Income Tax	-
Net Pension/OPEB Liability - Deduction	$ -
Portion Applicable to Delivery Service	91.68%
Net Pension / OPEB Liability	-

ROCKLAND ELECTRIC COMPANY
CUSTOMER ADVANCES FOR CONSTRUCTION
AND CUSTOMER DEPOSITS
AT SEPTEMBER 30, 2019
($ 000s)

Month		Customer Advances For Construction (1)	Customer Deposits (2)
Oct-18	(Actual)	1,544	2,901
Nov-18	(Actual)	1,905	2,832
Dec-18	(Actual)	2,186	2,834
Jan-19	(Actual)	2,181	2,790
Feb-19	(Actual)	2,142	2,782
Mar-19	(Actual)	2,016	2,810
Apr-19	Forecast	1,601	3,055
May-19	Forecast	1,415	3,099
Jun-19	Forecast	1,693	3,102
Jul-19	Forecast	1,712	3,089
Aug-19	Forecast	1,671	2,892
Sep-19	Forecast	1,581	2,873
	Twelve Month Total	$ 21,647	$ 35,059
	Monthly Average	$ 1,804	$ 2,922

ROCKLAND ELECTRIC COMPANY
ACCUMULATED DEFERRED INCOME TAXES
AT SEPTEMBER 30, 2019
($ 000s)

Beginning Balance at March 31, 2019	Total	Transmission Allocation 8.32%	Distribution Allocation 91.68%
Statutory Tax Depreciation	$ 36,901	$ 3,070	$ 33,831
Section 263A Deduction for Capitalized Overheads	12,787	1,064	11,723
Materials and Supplies	1,095	91	1,004
Contribution in Aid of Construction	(634)	(53)	(581)
AFUDC	434	36	398
Cost of Removal	2,917	243	2,674
OPEB Capitalized	12	1	11
Repair Allowance	15,310	1,274	14,036
Mangement Benefit	462	38	424
Misc Other	220	18	202
Other Tax Diff	16	1	15
Avoided Cost	(92)	(8)	(84)
Excess Deferred Fed Income Tax	9,492	790	8,702
Total	78,919	6,565	72,354
Additions / Amortizations (April to Sept 2019)			
Statutory Tax Depreciation	$ 979	81	898
Section 263A Deduction for Capitalized Overheads	153	13	140
Materials and Supplies	94	8	86
Contribution in Aid of Construction	64	5	59
AFUDC	(11)	(1)	(10)
Cost of Removal	68	6	62
OPEB Capitalized	(0)	-	(0)
Repair Allowance	765	64	701
Mangement Benefit	89	7	82
Misc Other	(6)	(1)	(5)
Other Tax Diff	(1)	-	(1)
Avoided Cost	2	-	2
Excess Deferred Fed Income Tax	(2,109)	(175)	(1,934)
Total	84	7	77
Ending Balance at September 30, 2019	$ 79,003	$ 6,572	$ 72,431
Post Test Year Adjustments (Oct 2019 to March 2020)			
Statutory Tax Depreciation	610	51	559
Section 263A Deduction for Capitalized Overheads	139	12	127
Materials and Supplies	63	5	58
Contribution in Aid of Construction	40	3	37
AFUDC	(7)	(1)	(6)
Cost of Removal	45	4	41
OPEB Capitalized	(0)	-	(0)
Repair Allowance	806	67	739
Mangement Benefit	79	7	72
Misc Other	(3)	-	(3)
Other Tax Diff	(1)	-	(1)
Avoided Cost	1	-	1
Excess Deferred Fed Income Tax	(1,694)	(141)	(1,553)
Total	77	7	70
Total As Adjusted	$ 79,080	$ 6,579	$ 72,501

ROCKLAND ELECTRIC COMPANY
MAJOR PLANT ADDITIONS
($000s)

Project Description	In Service Date	Budget April - June 2019	July - Sept. 2019	Oct. - Dec. 2019	Jan. - March 2020	Total Project Costs
Projects Over $250k						
Reserve at Franklin Lakes Phase 1	201904	350				350
Closter Breaker Replacements	201905	1,545				1,545
Ringwood Breaker 983/984-78-2	201905	597	4			601
Sweetwater Lane, Ringwood	201907		809			809
Allendale Breaker T588-239 Replacement	201910			350		350
Old Tappan - Howard Drive	201910			470		470
Wyckoff Automation/Resiliency	201910			416		416
Montvale - Main St 4kV Conversion	201911			325		325
Franklin Lakes-Old Mill Road Wyckoff Support	201912			550		550
Oakland - Long Hill Rd Hendrix	201912			350		350
Orangeburg Rd UG Ckt 30-7-13	201912			410		410
Allendale 39-1 and 39-6 Reroute	202003				1,650	1,650
Blanche Rd UG Ckt 28-3-13	202003				1,590	1,590
Harrington Park - Hackensack Ave Hendrix Rebuild	202003				300	300
AMI Program	Various	1,106	18	13	500	1,637
		3,598	831	2,884	4,040	11,353
Projects Under $250k						
Fieldstone Drive, Ringwood	201904	193				193
Iron Latch Ct, Upper Saddle River	201906	26				26
Orchard Ridge at Mahwah	201907		126			126
West Milford - Marshall Hill Road	201912			97		97
		219	126	97	-	442
Distribution Reliability Blanket	Various	4	50	71	238	363
Electric Distribution Blankets	Various	1,186	1,256	1,313	951	4,706
Electric Meter and Transformer Blankets	Various	201	159	251	174	785
Smart Grid Automation and Resiliency Program	Various	751	1,371	752	500	3,374
U/G Circuit Relocation and Rebuild	Various	57	116	573		746
All Other Electric Blankets	Various	113	61	10	20	204
Total		**$ 6,129**	**$ 3,970**	**$ 5,951**	**$ 5,923**	**$ 21,973**

ROCKLAND ELECTRIC COMPANY
CONSOLIDATED TAX DEDUCTION

($000s)

Consolidated Tax Losses Allocated to RECO			
Tax Years 2014-2017	$	(88)	
Tax Year 2018 Estimated Based on 2017 Actuals		(12)	
Total Tax Losses		(100)	
Revenue Requirement Allocation		25%	(a)
Allocated Tax Losses		(25)	
Portion Applicable to Delivery Service		91.68%	
Net Consolidated Tax Deduction	$	(23)	

(a) Based on the "Order Modifying the Board's Current Consolidated Tax Adjustment Policy" in Docket No. EO12121772, page 12 the CTA adjustment should be allocated so that the revenue requirement of the Company is reduced by 25% of the adjustment.

ROCKLAND ELECTRIC COMPANY
INDEX OF SCHEDULES

Orange and Rockland Utilities, Inc. and Subsidiaries
Consolidated Capitalization and Cost Rates

Exhibit P-4
Schedule 1

ROCKLAND ELECTRIC COMPANY

Consolidated Capitalization
Orange and Rockland Utilities, Inc. and Utility Subsidiaries
At March 31, 2019 (Actual)

Long Term Debt		Amount	Percent	Cost	Weighted Cost
Orange and Rockland	$	711,041,667			
Total Unamortized Costs		(7,737,218)			
Total Long Term Debt	$	703,304,449	48.64%	5.25%	2.55%
Subtotal	$	703,304,449			
Common Stock Equity					
Common Stock	$	5,000			
Premium on Capital Stock		349,071,874			
Capital Stock Expense		(166,651)			
Equity Issuance		20,000,000			
Retained Earnings		373,641,113			
Total Common Stock Equity	$	742,551,336	51.36%	9.60%	4.93%
Total Capitalization	$	1,445,855,785	100.00%		7.48%

ROCKLAND ELECTRIC COMPANY

Consolidated Capitalization
Orange and Rockland Utilities, Inc. and Utility Subsidiaries
At September 30, 2019 (Forecast)

Long Term Debt		Amount	Percent	Cost	Weighted Cost
Orange and Rockland	$	765,208,333			
Total Unamortized Costs		(8,222,362)			
Total Long Term Debt	$	756,985,971	50.07%	5.14%	2.57%
Subtotal	$	756,985,971			
Common Stock Equity					
Common Stock	$	5,000			
Premium on Capital Stock		349,071,874			
Capital Stock Expense		(166,651)			
Equity Issuance		20,000,000			
Retained Earnings		385,837,744			
Total Common Stock Equity	$	754,747,966	49.93%	10.00%	4.99%
Total Capitalization	$	1,511,733,938	100.00%		7.56%

ROCKLAND ELECTRIC COMPANY

ORANGE AND ROCKLAND UTILITIES, INC. AND SUBSIDIARIES

Long-Term Debt

At March 31, 2019 (Actual)

.

	Issue Date	Maturity Date	Amount Outstanding	Original Issue Amount	Premium or Discount	Expense of Issuance	Net Proceeds	Actual Cost of Money	Effective Annual Cost
Orange and Rockland Utilities									
Debentures:									
Series E/F 6.50% due 12/01/27	12/18/97	12/1/27	$ 80,000,000.0	$ 80,000,000.0	$ -	$ (905,000.0)	$ 79,095,000.0	6.50%	$ 5,200,000.0
Ser. A 2008, 6.15%, due 9/1/18	8/25/08	9/1/18	20,833,333	50,000,000	(89,500)	(537,601)	49,372,899	6.15%	1,281,250
Ser. A 2009, 4.96%, due 12/1/19	12/10/09	12/1/19	60,000,000	60,000,000	0	(480,529)	59,519,471	4.96%	2,976,000
Ser. B 2009, 6.00%, due 12/1/39	12/10/09	12/1/39	60,000,000	60,000,000	0	(616,117)	59,383,883	6.00%	3,600,000
Ser. B 2010, 5.50%, due 8/10/40	8/12/10	8/15/40	115,000,000	115,000,000	(218,500)	(1,156,872)	113,624,628	5.50%	6,325,000
Ser. A 2015, 4.95%, due 7/1/45	6/18/15	7/1/45	120,000,000	120,000,000	(727,200)	(1,440,515)	117,832,285	4.95%	5,940,000
Ser. B 2015, 4.69%, due 12/1/45	12/7/15	12/1/45	100,000,000	100,000,000	0	(1,126,771)	98,873,229	4.69%	4,690,000
Ser. A 2016, 3.88%, due 12/1/46	12/14/16	12/1/46	75,000,000	75,000,000	0	(593,412)	74,406,588	3.88%	2,910,000
Ser. A 2018, 4.35%, due 9/1/48	8/28/18	9/1/48	72,916,667	125,000,000	0	(716,055)	124,283,945	4.35%	3,171,875
Ser. B 2018, 4.35%, due 9/1/48	12/20/18	9/1/48	7,291,667	25,000,000	0	(151,075)	24,848,925	4.35%	317,188
Sub Total ORU Debt			$ 711,041,666.7					5.12%	$ 36,411,313
Unamortized Discount			(791,153)						35,253
Unamortized Debt Expenses			(5,206,560)						280,468
Unamortized Loss on Reacquired Debt			(1,739,505)						175,416
Total ORU			703,304,449					5.25%	36,902,449
Total Consolidated			**$ 703,304,449**					**5.25%**	**$ 36,902,449**

ROCKLAND ELECTRIC COMPANY

ORANGE AND ROCKLAND UTILITIES, INC. AND SUBSIDIARIES
Long-Term Debt
At September 30, 2019 (Forecast)

	Issue Date	Maturity Date	Amount Outstanding	Original Issue Amount	Premium or Discount	Expense of Issuance	Net Proceeds	Actual Cost of Money	Effective Annual Cost
Orange and Rockland Utilities									
Debentures:									
Series E/F 6.50% due 12/01/27	12/18/97	12/1/27	$ 80,000,000	$ 80,000,000	$ -	$ (905,000)	$ 79,095,000	6.50%	$ 5,200,000
Ser. A 2009, 4.96%, due 12/1/19	12/10/09	12/1/19	60,000,000	60,000,000	0	(480,529)	59,519,471	4.96%	2,976,000
Ser. B 2009, 6.00%, due 12/1/39	12/10/09	12/1/39	60,000,000	60,000,000	0	(616,117)	59,383,883	6.00%	3,600,000
Ser. B 2010, 5.50%, due 8/10/40	8/9/10	8/15/40	115,000,000	115,000,000	(218,500)	(1,156,872)	113,624,628	5.50%	6,325,000
Ser. A 2015, 4.95%, due 7/1/45	6/18/15	7/1/45	120,000,000	120,000,000	(727,200)	(1,440,515)	117,832,285	4.95%	5,940,000
Ser. B 2015, 4.69%, due 12/1/45	12/7/15	12/1/45	100,000,000	100,000,000	0	(1,126,771)	98,873,229	4.69%	4,690,000
Ser. A 2016, 3.88%, due 12/1/46	12/14/16	12/1/46	75,000,000	75,000,000	0	(593,412)	74,406,588	3.88%	2,910,000
Ser. A 2018, 4.35%, due 9/1/48	8/28/18	9/1/48	125,000,000	125,000,000	0	(716,055)	124,283,945	4.35%	5,437,500
Ser. B 2018, 4.35%, due 9/1/48	12/20/18	9/1/48	19,791,667	25,000,000	0	(151,075)	24,848,925	4.35%	860,938
Ser. A 2019, 5.20%, due 9/1/49	9/1/19	9/1/49	10,416,667	125,000,000	0	(725,000)	124,275,000	4.60%	479,167
Sub Total ORU Debt			$ 765,208,333					5.02%	$ 38,418,604
Unamortized Discount			(775,386)						31,523
Unamortized Debt Expenses			(5,795,179)						272,545
Unamortized Loss on Reacquired Debt			(1,651,797)						175,416
Total ORU			756,985,971					5.14%	38,898,088
Total Consolidated			**$ 756,985,971**					**5.14%**	**$ 38,898,088**

Exhibit P-4
Schedule 3

ROCKLAND ELECTRIC COMPANY

INDEX OF SCHEDULES

Present and Proposed Electric Rate Design

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 1

		Present		Proposed	
		Summer	Winter	Summer	Winter
Customer Charge:	per month	$4.53	$4.53	$6.50	$6.50
Distribution Charge:					
First 600 kWh	¢ per kWh	4.394	4.394	6.165	6.165
Over 600 kWh	¢ per kWh	5.537	4.394	7.765	6.165
Transmission Charge (incl Trans Surch):					
All kWh	¢ per kWh	3.345	3.345	3.345	3.345
RGGI Surcharge	¢ per kWh	0.0921	0.0921	0.0921	0.0921
Societal Benefits Charge	¢ per kWh	0.6050	0.6050	0.6050	0.6050
Securitization Charges:					
TBC	¢ per kWh	0.276	0.276	0.276	0.276
TBC-Tax	¢ per kWh	0.052	0.052	0.052	0.052
Total	¢ per kWh	0.328	0.328	0.328	0.328
Temporary Tax Act Credit	¢ per kWh	(0.235)	(0.235)	(0.235)	(0.235)
ZEC Recovery Charge	¢ per kWh	0.400	0.400	0.400	0.400
Basic Generation Service:					
First 600 kWh	¢ per kWh	6.474	8.382	6.474	8.382
Over 600 kWh	¢ per kWh	9.835	8.382	9.835	8.382
Reconciliation Charge	¢ per kWh	Variable	Variable	Variable	Variable
Minimum Charge:					
Monthly	monthly	$4.53		$6.50	
Per Contract	per contract	$27.18		$39.00	

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 2
Secondary Demand Billed

		Present		Proposed	
		Summer	Winter	Summer	Winter
Customer Charge:	per month	$16.37	$16.37	$21.01	$21.01
Distribution Charge:					
Demand Charge					
First 5 kW	per kW	$1.76	$1.47	$4.53	$3.79
Over 5 kW	per kW	3.53	2.99	7.12	6.00
Usage Charge					
First 4,920 kWh	¢ per kWh	3.427	3.212	3.271	3.088
Over 4,920 kWh	¢ per kWh	2.874	2.821	2.856	2.795
Transmission Charge (incl Trans Surch):					
Demand Charge					
All kW	per kW	$1.41	$1.18	$1.41	$1.18
Usage Charge					
All kWh	¢ per kWh	1.105	1.105	1.105	1.105
RGGI Surcharge	¢ per kWh	0.0921	0.0921	0.0921	0.0921
Societal Benefits Charge	¢ per kWh	0.6050	0.6050	0.6050	0.6050
Securitization Charges:					
TBC	¢ per kWh	0.276	0.276	0.276	0.276
TBC-Tax	¢ per kWh	0.052	0.052	0.052	0.052
Total	¢ per kWh	0.328	0.328	0.328	0.328
Temporary Tax Act Credit	¢ per kWh	(0.2350)	(0.2350)	(0.2350)	(0.2350)
ZEC Recovery Charge	¢ per kWh	0.4000	0.4000	0.4000	0.4000

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 2
Secondary Demand Billed (Continued)

Basic Generation Service: (Non-CIEP Billed)		Present Summer	Present Winter	Proposed Summer	Proposed Winter
Demand Charge					
First 5 kW	per kW	$1.81	$1.48	$1.81	$1.48
Over 5 kW	per kW	6.27	5.23	6.27	5.23
Usage Charge					
First 4,920 kWh	¢ per kWh	5.651	5.210	5.651	5.210
Reconciliation Charge	¢ per kWh	Variable	Variable	Variable	Variable
Minimum Charge:		$16.37	plus the demand charge	$21.01	plus the demand charge

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 2
Secondary Non-Demand Billed - Metered

		Present		Proposed	
		Summer	Winter	Summer	Winter
Customer Charge:	per month	$12.26	$12.26	$16.00	$16.00
Distribution Charge:					
Usage Charge					
All kWh	¢ per kWh	3.511	3.182	4.328	3.922
Transmission Charge (incl Trans Surch):					
Usage Charge					
All kWh	¢ per kWh	1.105	1.105	1.105	1.105
RGGI Surcharge	¢ per kWh	0.0921	0.0921	0.0921	0.0921
Societal Benefits Charge	¢ per kWh	0.6050	0.6050	0.6050	0.6050
Securitization Charges:					
TBC	¢ per kWh	0.276	0.276	0.276	0.276
TBC-Tax	¢ per kWh	0.052	0.052	0.052	0.052
Total	¢ per kWh	0.328	0.328	0.328	0.328
Temporary Tax Act Credit	¢ per kWh	(0.2350)	(0.2350)	(0.2350)	(0.2350)
ZEC Recovery Charge	¢ per kWh	0.4000	0.4000	0.4000	0.4000
Basic Generation Service:					
Usage Charge					
All kWh	¢ per kWh	7.358	6.425	7.358	6.425
Reconciliation Charge	¢ per kWh	Variable	Variable	Variable	Variable
Minimum Charge:		$12.26		$16.00	

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 2
Secondary Non-Demand Billed - Unmetered

		Present		Proposed	
		Summer	Winter	Summer	Winter
Customer Charge:	per month	$10.57	$10.57	$14.00	$14.00
Distribution Charge:					
Usage Charge					
All kWh	¢ per kWh	3.511	3.182	4.328	3.922
Transmission Charge (incl Trans Surch):					
Usage Charge					
All kWh	¢ per kWh	1.105	1.105	1.105	1.105
RGGI Surcharge	¢ per kWh	0.0921	0.0921	0.0921	0.0921
Societal Benefits Charge	¢ per kWh	0.6050	0.6050	0.6050	0.6050
Securitization Charges:					
TBC	¢ per kWh	0.276	0.276	0.276	0.276
TBC-Tax	¢ per kWh	0.052	0.052	0.052	0.052
Total	¢ per kWh	0.328	0.328	0.328	0.328
Temporary Tax Act Credit	¢ per kWh	(0.2350)	(0.2350)	(0.2350)	(0.2350)
ZEC Recovery Charge	¢ per kWh	0.4000	0.4000	0.4000	0.4000
Basic Generation Service:					
Usage Charge					
All kWh	¢ per kWh	7.358	6.425	7.358	6.425
Reconciliation Charge	¢ per kWh	Variable	Variable	Variable	Variable
Minimum Charge:		$10.57		$14.00	

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 2
Space Heating

		Present		Proposed	
		Summer	Winter	Summer	Winter
Distribution Charge:					
Usage Charge					
All kWh	¢ per kWh	4.478	2.688	6.295	3.779
Transmission Charge (incl Trans Surch):					
All kWh	¢ per kWh	1.105	1.105	1.105	1.105
RGGI Surcharge	¢ per kWh	0.0921	0.0921	0.0921	0.0921
Societal Benefits Charge	¢ per kWh	0.6050	0.6050	0.6050	0.6050
Securitization Charges:					
TBC	¢ per kWh	0.276	0.276	0.276	0.276
TBC-Tax	¢ per kWh	0.052	0.052	0.052	0.052
Total	¢ per kWh	0.328	0.328	0.328	0.328
Temporary Tax Act Credit	¢ per kWh	(0.2350)	(0.2350)	(0.2350)	(0.2350)
ZEC Recovery Charge	¢ per kWh	0.4000	0.4000	0.4000	0.4000
Basic Generation Service:					
Usage Charge					
All kWh	¢ per kWh	7.358	6.425	7.358	6.425
Reconciliation Charge	¢ per kWh	Variable	Variable	Variable	Variable

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 2
Primary

		Present		Proposed	
		Summer	Winter	Summer	Winter
Customer Charge:	per month	$85.30	$85.30	$92.00	$92.00
Distribution Charge:					
Demand Charge					
All kW	per kW	$6.90	$5.91	$7.70	$6.60
Usage Charge					
All kWh	¢ per kWh	1.485	1.485	1.485	1.485
Transmission Charge (incl Trans Surch):					
Demand Charge					
All kW	per kW	$1.41	$1.27	$1.41	$1.27
Usage Charge					
All kWh	¢ per kWh	1.105	1.105	1.105	1.105
RGGI Surcharge	¢ per kWh	0.0921	0.0921	0.0921	0.0921
Societal Benefits Charge	¢ per kWh	0.6050	0.6050	0.6050	0.6050
Securitization Charges:					
TBC	¢ per kWh	0.276	0.276	0.276	0.276
TBC-Tax	¢ per kWh	0.052	0.052	0.052	0.052
Total	¢ per kWh	0.328	0.328	0.328	0.328
Temporary Tax Act Credit	¢ per kWh	(0.2350)	(0.2350)	(0.2350)	(0.2350)
ZEC Recovery Charge	¢ per kWh	0.4000	0.4000	0.4000	0.4000

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 2
Primary (Continued)

Basic Generation Service: (Non-CIEP Billed)		Present Summer	Present Winter	Proposed Summer	Proposed Winter
Demand Charge					
First 5 kW	per kW	$1.81	$1.48	$1.81	$1.48
Over 5 kW	per kW	6.27	5.23	6.27	5.23
Usage Charge					
All kWh	¢ per kWh	5.651	5.210	5.651	5.210
Reconciliation Charge	¢ per kWh	Variable	Variable	Variable	Variable
Minimum Charge:		$85.30	plus the demand charge	$92.00	plus the demand charge

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 3

		Present Summer	Present Winter	Proposed Summer	Proposed Winter
Customer Charge:	per month	$6.50	$6.50	$9.00	$9.00
Distribution Charge:					
All kWh, Monday to Friday, 10 A.M. to 10 P.M.	¢ per kWh	6.009	5.391	8.463	7.592
All Other kWh	¢ per kWh	2.164	2.164	3.048	3.048
Transmission Charge (incl Trans Surch):					
All kWh	¢ per kWh	2.122	2.122	2.122	2.122
RGGI Surcharge	¢ per kWh	0.0921	0.0921	0.0921	0.0921
Societal Benefits Charge	¢ per kWh	0.6050	0.6050	0.6050	0.6050
Securitization Charges:					
TBC	¢ per kWh	0.276	0.276	0.276	0.276
TBC-Tax	¢ per kWh	0.052	0.052	0.052	0.052
Total	¢ per kWh	0.328	0.328	0.328	0.328
Temporary Tax Act Credit	¢ per kWh	(0.2350)	(0.2350)	(0.2350)	(0.2350)
ZEC Recovery Charge	¢ per kWh	0.4000	0.4000	0.4000	0.4000
Basic Generation Service:					
All kWh, Monday to Friday, 10 A.M. to 10 P.M.	¢ per kWh	12.362	9.788	12.362	9.788
All Other kWh	¢ per kWh	5.113	5.019	5.113	5.019
Reconciliation Charge	¢ per kWh	Variable	Variable	Variable	Variable
Minimum Charge:					
The Customer Charge, not less than		$78.00	per contract.	$108.00	per contract.

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 4

Luminaries Charge, per month

Nominal Lumens	Luminaires Type	Watts	Total Wattage	Present Distribution Charge	Proposed Distribution Charge
Street Lighting Luminaires					
5,800	Sodium Vapor	70	108	$7.60	$9.47
9,500	Sodium Vapor	100	142	8.25	10.28
16,000	Sodium Vapor	150	199	10.04	12.51
27,500	Sodium Vapor	250	311	12.82	15.96
46,000	Sodium Vapor	400	488	20.79	25.89
3,000	LED	20-25	23	N/A	8.21
3,900	LED	30-39	35	N/A	8.05
5,000	LED	40-59	50	N/A	8.07
7,250	LED	60-79	68	N/A	8.41
12,000	LED	95-110	103	N/A	9.46
16,000	LED	130-150	140	N/A	9.92
22,000	LED	180-220	200	N/A	14.53
LED Flood Lighitng Luminaires					
15,500	LED	115-130	125	N/A	$11.43
27,000	LED	175-225	205	N/A	14.58
37,500	LED	265-315	290	N/A	15.88

The following luminaires will no longer be installed. Charges are for existing luminaires only.

Nominal Lumens	Luminaires Type	Watts	Total Wattage	Present Distribution Charge	Proposed Distribution Charge
Post Top Luminaries					
16,000	Sodium Vapor-Offset	150	199	$20.29	$25.27
Street Lighting Luminaires					
1,000	Open Bottom Inc	92	92	$5.03	$6.27
4,000	Mercury Vapor	100	127	6.81	8.49
7,900	Mercury Vapor	175	211	8.03	10.00
12,000	Mercury Vapor	250	296	10.44	13.00
22,500	Mercury Vapor	400	459	13.25	16.51
40,000	Mercury Vapor	700	786	20.15	25.10
59,000	Mercury Vapor	1,000	1,105	25.47	31.72

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 4 (Continued)

Nominal Lumens	Luminaires Type	Watts	Total Wattage	Present Distribution Charge		Proposed Distribution Charge	
Street Lighting Luminaires (Continued)							
3,400	Induction	40	45	$7.95		$9.91	
5,950	Induction	70	75	8.10		10.09	
8,500	Induction	100	110	9.15		11.39	
5,890	LED	70	74	8.71		10.84	
9,365	LED	100	101	10.69		13.32	
Post-Top Luminaires							
4,000	Mercury Vapor	100	130	$10.36		$12.90	
7,900	Mercury Vapor	175	215	12.70		15.81	
7,900	Mercury Vapor – Off-Set	175	215	14.92		18.57	
Additional Charge:							
UG Svc- Company owned and maintained -				$17.35	per mo.	$21.60	per mo.
UG Svc- Customer owned and maintained -				$4.22	per mo.	$5.26	per mo.
15 Foot Brackets				$0.47	per mo.	$0.59	per mo.
Transmission Charge (incl Trans Surch):				1.2240	¢ per kWh	1.2240	¢ per kWh
RGGI Surcharge				0.0921	¢ per kWh	0.0921	¢ per kWh
Societal Benefits Charge				0.6050	¢ per kWh	0.6050	¢ per kWh
Securitization Charges:							
TBC				0.276	¢ per kWh	0.276	¢ per kWh
TBC-Tax				0.052	¢ per kWh	0.052	¢ per kWh
Total				0.328	¢ per kWh	0.328	¢ per kWh
Temporary Tax Act Credit				(0.235)	¢ per kWh	(0.235)	¢ per kWh
ZEC Recovery Surcharge				0.400	¢ per kWh	0.400	¢ per kWh
Basic Generation Service:							
Summer				5.113	¢ per kWh	5.113	¢ per kWh
Winter				5.019	¢ per kWh	5.019	¢ per kWh
Reconciliation Charge				Variable	¢ per kWh	Variable	¢ per kWh

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 5

		Present		Proposed	
		Summer	Winter	Summer	Winter
Customer Charge:	per month	$4.53	$4.53	$6.50	$6.50
Distribution Charge:					
First 600 kWh	¢ per kWh	4.460	4.460	6.165	6.165
Over 600 kWh	¢ per kWh	5.420	4.460	7.765	6.165
Transmission Charge (incl Trans Surch):					
All kWh	¢ per kWh	2.175	2.175	2.175	2.175
RGGI Surcharge	¢ per kWh	0.0921	0.0921	0.0921	0.0921
Societal Benefit Charge	¢ per kWh	0.6050	0.6050	0.6050	0.6050
Securitization Charges:					
TBC	¢ per kWh	0.276	0.276	0.276	0.276
TBC-Tax	¢ per kWh	0.052	0.052	0.052	0.052
Total	¢ per kWh	0.328	0.328	0.328	0.328
Temporary Tax Act Credit	¢ per kWh	(0.235)	(0.235)	(0.235)	(0.235)
ZEC Recovery Charge	¢ per kWh	0.400	0.400	0.400	0.400
Basic Generation Service:					
First 600 kWh	¢ per kWh	6.793	6.821	6.793	6.821
Over 600 kWh	¢ per kWh	9.165	6.821	9.165	6.821
Reconciliation Charge	¢ per kWh	Variable	Variable	Variable	Variable
Minimum Charge: Monthly		$4.53		$6.50	
Minimum Per Contract		$27.18		$39.00	

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 6

Luminaire Charges for Service Types A and B, monthly

Nominal Lumens	Luminaire Type	Watts	Total Wattage	Present Distribution Charge	Proposed Distribution Charge
Power Bracket Luminaires					
5,800	Sodium Vapor	70	108	$5.34	$7.51
9,500	Sodium Vapor	100	142	6.42	9.02
16,000	Sodium Vapor	150	199	6.89	9.68
3,950	LED	30-44	35	N/A	7.57
5,550	LED	45-59	50	N/A	7.68
7,350	LED	60-70	65	N/A	7.75
Street Lighting Luminaires					
5,800	Sodium Vapor	70	108	$7.43	$10.45
9,500	Sodium Vapor	100	142	8.16	11.46
16,000	Sodium Vapor	150	199	10.02	14.09
27,500	Sodium Vapor	250	311	12.86	18.07
46,000	Sodium Vapor	400	488	21.22	29.83
3,000	LED	20-25	23	N/A	8.21
3,900	LED	30-39	35	N/A	8.05
5,000	LED	40-59	50	N/A	8.07
7,250	LED	60-79	68	N/A	8.41
12,000	LED	95-110	103	N/A	9.46
16,000	LED	130-150	140	N/A	9.92
22,000	LED	180-220	200	N/A	14.53
Flood lighting Luminaires					
46,000	Sodium Vapor	400	488	$21.22	$29.83
15,500	LED	115-130	125	N/A	11.43
27,000	LED	175-225	205	N/A	14.58
37,500	LED	265-315	290	N/A	15.88

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 6 (Continued)

Luminaire Charges for Service Types A and B, monthly

Nominal Lumens	Luminaire Type	Watts	Total Wattage	Present Distribution Charge	Proposed Distribution Charge
The following luminaires will no longer be installed. Charges are for existing luminaires only.					
Post Top Luminaires					
16,000	Sodium Vapor-Offset	150	199	$19.73	$27.73
Power Bracket Luminaires					
4,000	Mercury Vapor	100	127	$8.30	$11.66
7,900	Mercury Vapor	175	215	9.59	13.48
22,500	Mercury Vapor	400	462	15.28	21.48
Street Lighting Luminaires					
4,000	Mercury Vapor	100	127	$9.12	$12.82
7,900	Mercury Vapor	175	211	10.42	14.64
22,500	Mercury Vapor	400	459	16.19	22.75
1,000	Incandescent	-	92	7.41	10.42
3,400	Induction	40	45	8.00	11.24
5,950	Induction	70	75	8.17	11.48
8,500	Induction	100	110	9.20	12.93
5,890	LED	70	74	8.75	12.30
9,365	LED	100	101	10.77	15.14
Flood lighting Luminaires					
12,000	Mercury Vapor	250	296	$13.10	$18.42
40,000	Mercury Vapor	700	786	23.72	33.35
59,000	Mercury Vapor	1,000	1,105	29.55	41.53

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 6 (Continued)

Luminaire Charges for Service Types A and B, monthly

Nominal Lumens	Luminaire Type	Watts	Total Wattage	Present Distribution Charge		Proposed Distribution Charge	
15 Ft Brackets				$0.52	per month	$0.74	per month

Distribution and Transmission Charges for Service Type C:

	Present		Proposed	
Metered				
Customer Charge (Metered)	$11.53	per month	$14.00	per month
Customer Charge (Unmetered)	2.40	per month	3.00	per month
Distribution Charge	4.992	¢ per kWh	6.251	¢ per kWh
Transmission Charge	1.224	¢ per kWh	1.224	¢ per kWh
RGGI Surcharge	0.0921	¢ per kWh	0.0921	¢ per kWh
Societal Benefit Charge	0.6050	¢ per kWh	0.6050	¢ per kWh
Securitization Charges:				
TBC	0.276	¢ per kWh	0.276	¢ per kWh
TBC-Tax	0.052	¢ per kWh	0.052	¢ per kWh
Total	0.328	¢ per kWh	0.328	¢ per kWh
Temporary Tax Act Credit	(0.235)	¢ per kWh	(0.235)	¢ per kWh
ZEC Recovery Surcharge	0.400	¢ per kWh	0.400	¢ per kWh
Basic Generation Service:				
Summer	5.015	¢ per kWh	5.015	¢ per kWh
Winter	4.985	¢ per kWh	4.985	¢ per kWh
Reconciliation Charge	Variable	¢ per kWh	Variable	¢ per kWh

Minimum Charges:

Type A or B:

Sum of the monthly Distribution and Transmission Charges as specified in RATE – MONTHLY, Part (1a) times twelve.

			Present	Proposed
Type C:	Metered	per month	$11.53	$14.00
		minimum for initial term	138.36	168.00
	Unmetered	per month	2.40	3.00
		minimum for initial term	28.80	36.00

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 7
Primary

			Present Year-round	Proposed Year-round
Customer Charge:		per month	$212.35	$250.00
Distribution Charge:				
Demand Charge				
Period I	All kW @	per kW	$2.94	$3.88
Period II	All kW @	per kW	0.73	0.96
Period III	All kW @	per kW	2.70	3.56
Period IV	All kW @	per kW	0.73	0.96
Usage Charge				
Period I	All kWh @	¢ per kWh	1.770	1.770
Period II	All kWh @	¢ per kWh	1.325	1.325
Period III	All kWh @	¢ per kWh	1.770	1.770
Period IV	All kWh @	¢ per kWh	1.325	1.325
Transmission Charge (incl Trans Surch):				
Demand Charge				
Period I	All kW @	per kW	$2.55	$2.55
Period II	All kW @	per kW	0.67	0.67
Period III	All kW @	per kW	2.55	2.55
Period IV	All kW @	per kW	0.67	0.67
Usage Charge				
All kWh @		¢ per kWh	0.779	0.779
RGGI Surcharge		¢ per kWh	0.0921	0.0921
Societal Benefits Charge		¢ per kWh	0.6050	0.6050
Securitization Charges:				
TBC		¢ per kWh	0.276	0.276
TBC-Tax		¢ per kWh	0.052	0.052
Total		¢ per kWh	0.328	0.328
Temporary Tax Act Credit		¢ per kWh	(0.235)	(0.235)
ZEC Recovery Surcharge		¢ per kWh	0.400	0.400
CIEP Standby Fee		¢ per kWh	0.01599	0.01599

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 7 (Continued)
Primary

		Present Year-round	Proposed Year-round
Basic Generation Service:			
Capacity Obligation Charge			
Summer	$/kW/Month	9.7561	9.7561
Winter	$/kW/Month	9.2151	9.2151
Hourly Energy Charge**	¢ per kWh	4.600	4.600
Ancillary Services	¢ per kWh	0.000	0.000
Retail Margin	¢ per kWh	0.000	0.000
Reconciliation Charge	¢ per kWh	Variable	Variable
Space Heating:			
Distribution Charge			
Summer	¢ per kWh	4.693	6.597
Winter	¢ per kWh	2.902	4.081
Transmission Charge (incl Trans Surch):			
Year-round	¢ per kWh	0.910	0.910

Definition of Rating Periods:

Period I - 10:00 a.m. to 10:00 p.m. prevailing time, Monday through Friday except holidays, June through September.

Period II - 10:00 p.m. to 10:00 a.m. prevailing time, Monday through Friday and all hours on Saturday, Sunday and holidays, June through September.

Period III - 10:00 a.m. to 10:00 p.m. prevailing time, Monday through Friday except holidays, October through May.

Period IV - 10:00 p.m. to 10:00 a.m. prevailing time, Monday through Friday, all hours on Saturday, Sunday and holidays, October through May.

Minimum Charge: The Customer Charge

** Average based on forecast of BGS Prices for 12 ME September, 2019

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 7
High Voltage Distribution

			Present	Proposed
			Year-round	Year-round
Customer Charge:		per month	$2,288.12	$2,288.12
Distribution Charge:				
Demand Charge				
Period I	All kW @	per kW	$0.92	$1.10
Period II	All kW @	per kW	0.21	0.26
Period III	All kW @	per kW	0.84	1.01
Period IV	All kW @	per kW	0.21	0.26
Usage Charge				
Period I	All kWh @	¢ per kWh	0.203	0.203
Period II	All kWh @	¢ per kWh	0.151	0.151
Period III	All kWh @	¢ per kWh	0.203	0.203
Period IV	All kWh @	¢ per kWh	0.151	0.151
Transmission Charge (incl Trans Surch):				
Demand Charge				
Period I	All kW @	per kW	$2.55	$2.55
Period II	All kW @	per kW	0.67	0.67
Period III	All kW @	per kW	2.55	2.55
Period IV	All kW @	per kW	0.67	0.67
Usage Charge				
All kWh @		¢ per kWh	0.779	0.779
RGGI Surcharge		¢ per kWh	0.0921	0.0921
Societal Benefits Charge		¢ per kWh	0.6050	0.6050
Securitization Charges:				
TBC		¢ per kWh	0.276	0.276
TBC-Tax		¢ per kWh	0.052	0.052
Total		¢ per kWh	0.328	0.328
Temporary Tax Act Credit		¢ per kWh	(0.235)	(0.235)
ZEC Recovery Surcharge		¢ per kWh	0.400	0.400
CIEP Standby Fee		¢ per kWh	0.01599	0.01599

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 7 (Continued)
High Voltage Distribution

		Present Year-round	Proposed Year-round
Basic Generation Service:			
Capacity Obligation Charge			
Summer	$/kW/Month	9.7561	9.7561
Winter	$/kW/Month	9.2151	9.2151
Hourly Energy Charge**	¢ per kWh	4.600	4.600
Ancillary Services	¢ per kWh	0.000	0.000
Retail Margin	¢ per kWh	0.000	0.000
Reconciliation Charge	¢ per kWh	Variable	Variable

Definition of Rating Periods:

Period I - 10:00 a.m. to 10:00 p.m. prevailing time, Monday through Friday except holidays, June through September.

Period II - 10:00 p.m. to 10:00 a.m. prevailing time, Monday through Friday and all hours on Saturday, Sunday and holidays, June through September.

Period III - 10:00 a.m. to 10:00 p.m. prevailing time, Monday through Friday except holidays, October through May.

Period IV - 10:00 p.m. to 10:00 a.m. prevailing time, Monday through Friday, all hours on Saturday, Sunday and holidays, October through May.

Definition of Rating Periods:

Minimum Charge: The Customer Charge

** Average based on forecast of BGS Prices for 12 ME September, 2019

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Calculation of Proposed Distribution Rates
Including Sales and Use Tax @ 6.625%

	Proposed Distribution Excl SUT (a)	Proposed Distribution SUT (b = a * 6.625%) 6.625%	Proposed Distribution Incl SUT (c = a + b)
Service Classification Nos. 1 and 5			
Customer Charge ($/mo)	6.10	0.40	6.50
First 600 kWh -S ($/kWh)	0.05782	0.00383	0.06165
First 600 kWh -W ($/kWh)	0.05782	0.00383	0.06165
Over 600 kWh -S ($/kWh)	0.07283	0.00482	0.07765
Over 600 kWh -W ($/kWh)	0.05782	0.00383	0.06165
Service Classification No. 2 Secondary Non-Demand Billed Unmetered			
Customer Charge ($/mo)	13.13	0.87	14.00
Usage:			
All kWh -S ($/kWh)	0.04059	0.00269	0.04328
All kWh -W ($/kWh)	0.03678	0.00244	0.03922
Service Classification No. 2 Secondary Non-Demand Billed Metered			
Customer Charge ($/mo)	15.01	0.99	16.00
Usage:			
All kWh -S ($/kWh)	0.04059	0.00269	0.04328
All kWh -W ($/kWh)	0.03678	0.00244	0.03922
Service Classification No. 2 Secondary Demand Billed			
Customer Charge ($/mo)	19.70	1.31	21.01
Demand:			
First 5 kW -S ($/kW)	4.25	0.28	4.53
First 5 kW -W ($/kW)	3.55	0.24	3.79
Over 5 kW -S ($/kW)	6.68	0.44	7.12
Over 5 kW -W ($/kW)	5.63	0.37	6.00
Usage:			
First 4,920 kWh -S ($/kWh)	0.03068	0.00203	0.03271
First 4,920 kWh -W ($/kWh)	0.02896	0.00192	0.03088
Over 4,920 kWh -S ($/kWh)	0.02679	0.00177	0.02856
Over 4,920 kWh -W ($/kWh)	0.02621	0.00174	0.02795
Service Classification No. 2 Space Heating			
Space Heat -S ($/kWh)	0.05904	0.00391	0.06295
Space Heat -W ($/kWh)	0.03544	0.00235	0.03779

ROCKLAND ELECTRIC COMPANY
Calculation of Proposed Distribution Rates
Including Sales and Use Tax @ 6.625%

	Proposed Distribution Excl SUT (a)	Proposed Distribution SUT (b = a * 6.625%) 6.625%	Proposed Distribution Incl SUT (c = a + b)
Service Classification No. 2 Primary			
Customer Charge ($/mo)	86.28	5.72	92.00
Demand:			
All kW -S ($/kW)	7.22	0.48	7.70
All kW -W ($/kW)	6.19	0.41	6.60
Usage:			
All kWh -S ($/kWh)	0.01393	0.00092	0.01485
All kWh -W ($/kWh)	0.01393	0.00092	0.01485
Service Classification No. 3			
Customer Charge ($/mo)	8.44	0.56	9.00
Peak -S ($/kWh)	0.07937	0.00526	0.08463
Peak -W ($/kWh)	0.07120	0.00472	0.07592
Off Peak - S ($/kWh)	0.02859	0.00189	0.03048
Off Peak - W ($/kWh)	0.02859	0.00189	0.03048
Service Classification No. 7			
Customer Charge ($/mo)	234.47	15.53	250.00
Demand			
Period I ($/kW)	3.64	0.24	3.88
Period II ($/kW)	0.90	0.06	0.96
Period III ($/kW)	3.34	0.22	3.56
Period IV ($/kW)	0.90	0.06	0.96
Usage:			
Period I ($/kWh)	0.01660	0.00110	0.01770
Period II ($/kWh)	0.01243	0.00082	0.01325
Period III ($/kWh)	0.01660	0.00110	0.01770
Period IV ($/kWh)	0.01243	0.00082	0.01325
Service Classification No. 7 High Voltage Distribution			
Customer Charge ($/mo)	2,145.95	142.17	2,288.12
Demand			
Period I ($/kW)	1.03	0.07	1.10
Period II ($/kW)	0.24	0.02	0.26
Period III ($/kW)	0.95	0.06	1.01
Period IV ($/kW)	0.24	0.02	0.26
Usage			
Period I ($/kWh)	0.00190	0.00013	0.00203
Period II ($/kWh)	0.00142	0.00009	0.00151
Period III ($/kWh)	0.00190	0.00013	0.00203
Period IV ($/kWh)	0.00142	0.00009	0.00151

ROCKLAND ELECTRIC COMPANY
Calculation of Proposed Distribution Rates
Including Sales and Use Tax @ 6.625%

	Proposed Distribution Excl SUT (a)	Proposed Distribution SUT (b = a * 6.625%) 6.625%	Proposed Distribution Incl SUT (c = a + b)
Service Classification No. 7 Space Heating			
Space Heat -S ($/kWh)	0.06187	0.00410	0.06597
Space Heat -W ($/kWh)	0.03827	0.00254	0.04081
Service Classification No. 4			
5800 SV ($/luminaire/mo.)	8.88	0.59	9.47
9500 SV	9.64	0.64	10.28
16000 SV	11.73	0.78	12.51
27500 SV	14.97	0.99	15.96
46000 SV	24.28	1.61	25.89
16000 SV Offset	23.70	1.57	25.27
1000 OBI	5.88	0.39	6.27
4000 MV	7.96	0.53	8.49
7900 MV	9.38	0.62	10.00
12000 MV	12.19	0.81	13.00
22500 MV	15.48	1.03	16.51
40000 MV	23.54	1.56	25.10
59000 MV	29.75	1.97	31.72
4000 MV	12.10	0.80	12.90
7900 MV	14.83	0.98	15.81
7900 MV Offset	17.42	1.15	18.57
3400 IN	9.29	0.62	9.91
5950 IN	9.46	0.63	10.09
8500 IN	10.68	0.71	11.39
5890 LED	10.17	0.67	10.84
9365 LED	12.49	0.83	13.32
3000 LED	7.70	0.51	8.21
3900 LED	7.55	0.50	8.05
5000 LED	7.57	0.50	8.07
7250 LED	7.89	0.52	8.41
12000 LED	8.87	0.59	9.46
16000 LED	9.30	0.62	9.92
22000 LED	13.63	0.90	14.53
15500 LED	10.72	0.71	11.43
27000 LED	13.67	0.91	14.58
37500 LED	14.89	0.99	15.88
15 Foot Brackets	0.55	0.04	0.59
Undrg - Co. Owned	20.26	1.34	21.60
Undrg - Cust. Owned	4.93	0.33	5.26

ROCKLAND ELECTRIC COMPANY
Calculation of Proposed Distribution Rates
Including Sales and Use Tax @ 6.625%

	Proposed Distribution Excl SUT (a)	Proposed Distribution SUT (b = a * 6.625%) 6.625%	Proposed Distribution Incl SUT (c = a + b)
Service Classification No. 6			
5800 SV ($/luminaire/mo.)	7.04	0.47	7.51
9500 SV	8.46	0.56	9.02
16000 SV	9.08	0.60	9.68
5800 SV	9.80	0.65	10.45
9500 SV	10.75	0.71	11.46
16000 SV	13.21	0.88	14.09
27500 SV	16.95	1.12	18.07
46000 SV	27.98	1.85	29.83
46000 SV	27.98	1.85	29.83
16000 SV Offset	26.01	1.72	27.73
4000 MV	10.94	0.72	11.66
7900 MV	12.64	0.84	13.48
22500 MV	20.15	1.33	21.48
4000 MV	12.02	0.80	12.82
7900 MV	13.73	0.91	14.64
22500 MV	21.34	1.41	22.75
1000 In	9.77	0.65	10.42
12000 MV	17.28	1.14	18.42
40000 MV	31.28	2.07	33.35
59000 MV	38.95	2.58	41.53
3400 IN	10.54	0.70	11.24
5950 IN	10.77	0.71	11.48
8500 IN	12.13	0.80	12.93
5890 LED	11.54	0.76	12.30
9365 LED	14.20	0.94	15.14
3000 LED	7.70	0.51	8.21
3900 LED	7.55	0.50	8.05
5000 LED	7.57	0.50	8.07
7250 LED	7.89	0.52	8.41
12000 LED	8.87	0.59	9.46
16000 LED	9.30	0.62	9.92
22000 LED	13.63	0.90	14.53
15500 LED	10.72	0.71	11.43
27000 LED	13.67	0.91	14.58
37500 LED	14.89	0.99	15.88
3950 LED	7.10	0.47	7.57
5550 LED	7.20	0.48	7.68
7350 LED	7.27	0.48	7.75
15 Foot Brackets	0.69	0.05	0.74
Service Classification No. 6			
Customer Charge - Metered	13.13	0.87	14.00
Customer Charge - Unmetered	2.81	0.19	3.00
Energy (kWh) - Summer	0.05863	0.00388	0.06251
Energy (kWh) - Winter	0.05863	0.00388	0.06251

ROCKLAND ELECTRIC COMPANY

Monthly Billing Comparisons

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY

Monthly Billing Comparisons

SC1 Residential

	Monthly Usage (kWh)	Bill at Present Rates	Bill at Proposed Rates	Change Amount	Change Percent
Summer					
	0	$4.53	$6.50	$1.97	43.5
	50	12.23	15.09	2.86	23.4
	100	19.93	23.67	3.74	18.8
	200	35.34	40.85	5.51	15.6
	250	43.04	49.44	6.40	14.9
	300	50.74	58.02	7.28	14.3
	400	66.14	75.20	9.06	13.7
	500	81.55	92.37	10.82	13.3
	750	126.81	142.75	15.94	12.6
	1,000	176.58	198.09	21.51	12.2
	1,500	276.11	308.76	32.65	11.8
	2,000	375.65	419.44	43.79	11.7
Winter					
	0	$4.53	$6.50	$1.97	43.5
	50	13.19	16.04	2.85	21.6
	100	21.84	25.58	3.74	17.1
	200	39.15	44.66	5.51	14.1
	250	47.81	54.21	6.40	13.4
	300	56.46	63.75	7.29	12.9
	400	73.77	82.83	9.06	12.3
	500	91.09	101.91	10.82	11.9
	750	134.36	149.62	15.26	11.4
	1,000	177.64	197.32	19.68	11.1
	1,500	264.20	292.73	28.53	10.8
	2,000	350.75	388.14	37.39	10.7

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY

Monthly Billing Comparisons

SC2 General Service - Unmetered

	Monthly Usage (kWh)	Bill at Present Rates	Bill at Proposed Rates	Change Amount	Change Percent
Summer					
	0	$10.57	$14.00	$3.43	32.5
	100	23.73	27.98	4.25	17.9
	200	36.90	41.96	5.06	13.7
	300	50.06	55.94	5.88	11.7
	400	63.23	69.92	6.69	10.6
	500	76.39	83.91	7.52	9.8
	750	109.30	118.86	9.56	8.7
	1,000	142.21	153.81	11.60	8.2
	1,250	175.12	188.76	13.64	7.8
	1,500	208.03	223.72	15.69	7.5
	1,750	240.94	258.67	17.73	7.4
	2,000	273.85	293.62	19.77	7.2
Winter					
	0	$10.57	$14.00	$3.43	32.5
	50	16.52	20.32	3.80	23.0
	100	22.47	26.64	4.17	18.6
	200	34.37	39.28	4.91	14.3
	250	40.33	45.61	5.28	13.1
	300	46.28	51.93	5.65	12.2
	400	58.18	64.57	6.39	11.0
	500	70.08	77.21	7.13	10.2
	750	99.84	108.82	8.98	9.0
	1,000	129.59	140.42	10.83	8.4
	1,500	189.10	203.63	14.53	7.7
	2,000	248.61	266.84	18.23	7.3

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY

Monthly Billing Comparisons

SC2 General Service - Non-Demand Metered

	Monthly Usage (kWh)	Bill at Present Rates	Bill at Proposed Rates	Change Amount	Change Percent
Summer					
	0	$12.26	$16.00	$3.74	30.5
	100	25.42	29.98	4.56	17.9
	200	38.59	43.96	5.37	13.9
	300	51.75	57.94	6.19	12.0
	400	64.92	71.92	7.00	10.8
	500	78.08	85.91	7.83	10.0
	750	110.99	120.86	9.87	8.9
	1,000	143.90	155.81	11.91	8.3
	1,250	176.81	190.76	13.95	7.9
	1,500	209.72	225.72	16.00	7.6
	1,750	242.63	260.67	18.04	7.4
	2,000	275.54	295.62	20.08	7.3
Winter					
	0	$12.26	$16.00	$3.74	30.5
	50	18.21	22.32	4.11	22.6
	100	24.16	28.64	4.48	18.5
	200	36.06	41.28	5.22	14.5
	250	42.02	47.61	5.59	13.3
	300	47.97	53.93	5.96	12.4
	400	59.87	66.57	6.70	11.2
	500	71.77	79.21	7.44	10.4
	750	101.53	110.82	9.29	9.2
	1,000	131.28	142.42	11.14	8.5
	1,500	190.79	205.63	14.84	7.8
	2,000	250.30	268.84	18.54	7.4

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY

Monthly Billing Comparisons

SC2 General Secondary Service - Summer

Demand (kW)	Monthly Usage (kWh)	Bill at Present Rates	Bill at Proposed Rates	Change Amount	Change Percent
7	700	$134.60	$159.18	$24.58	18.3
7	1,400	208.33	231.82	23.49	11.3
7	2,100	282.07	304.46	22.39	7.9
7	2,800	355.80	377.10	21.30	6.0
10	1,000	195.60	230.48	34.88	17.8
10	2,000	300.93	334.25	33.32	11.1
10	3,000	406.26	438.02	31.76	7.8
10	4,000	511.59	541.79	30.20	5.9
25	2,500	500.60	586.99	86.39	17.3
25	5,000	758.96	841.56	82.60	10.9
25	7,500	867.19	949.34	82.15	9.5
25	10,000	975.42	1,057.12	81.70	8.4
50	5,000	1,003.96	1,176.31	172.35	17.2
50	10,000	1,220.42	1,391.87	171.45	14.0
50	15,000	1,436.87	1,607.42	170.55	11.9
50	20,000	1,653.33	1,822.98	169.65	10.3
100	10,000	1,710.42	2,061.37	350.95	20.5
100	20,000	2,143.33	2,492.48	349.15	16.3
100	30,000	2,576.24	2,923.59	347.35	13.5
100	40,000	3,009.15	3,354.70	345.55	11.5
150	15,000	2,416.87	2,946.42	529.55	21.9
150	30,000	3,066.24	3,593.09	526.85	17.2
150	45,000	3,715.60	4,239.75	524.15	14.1
150	60,000	4,364.97	4,886.42	521.45	11.9

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY

Monthly Billing Comparisons

SC2 General Secondary Service - Winter

Demand (kW)	Monthly Usage (kWh)	Bill at Present Rates	Bill at Proposed Rates	Change Amount	Change Percent
7	700	$122.60	$143.99	$21.39	17.4
7	1,400	191.74	212.26	20.52	10.7
7	2,100	260.88	280.54	19.66	7.5
7	2,800	330.02	348.81	18.79	5.7
10	1,000	176.89	206.94	30.05	17.0
10	2,000	275.66	304.47	28.81	10.5
10	3,000	374.43	402.00	27.57	7.4
10	4,000	473.20	499.53	26.33	5.6
25	2,500	448.35	521.69	73.34	16.4
25	5,000	690.79	761.11	70.32	10.2
25	7,500	797.70	867.37	69.67	8.7
25	10,000	904.60	973.62	69.02	7.6
50	5,000	896.29	1,041.86	145.57	16.2
50	10,000	1,110.10	1,254.37	144.27	13.0
50	15,000	1,323.90	1,466.87	142.97	10.8
50	20,000	1,537.71	1,679.38	141.67	9.2
100	10,000	1,521.10	1,815.87	294.77	19.4
100	20,000	1,948.71	2,240.88	292.17	15.0
100	30,000	2,376.32	2,665.89	289.57	12.2
100	40,000	2,803.93	3,090.90	286.97	10.2
150	15,000	2,145.90	2,589.87	443.97	20.7
150	30,000	2,787.32	3,227.39	440.07	15.8
150	45,000	3,428.73	3,864.90	436.17	12.7
150	60,000	4,070.15	4,502.42	432.27	10.6

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY

Monthly Billing Comparisons

SC2 General Primary Service - Summer

Demand (kW)	Monthly Usage (kWh)	Bill at Present Rates	Bill at Proposed Rates	Change Amount	Change Percent
100	20,000	$3,273.27	$3,359.97	$86.70	2.6
100	30,000	4,216.38	4,303.08	86.70	2.1
100	40,000	5,159.49	5,246.19	86.70	1.7
100	50,000	6,102.60	6,189.30	86.70	1.4
150	30,000	4,874.88	5,001.58	126.70	2.6
150	45,000	6,289.55	6,416.25	126.70	2.0
150	60,000	7,704.21	7,830.91	126.70	1.6
150	75,000	9,118.88	9,245.58	126.70	1.4
200	40,000	6,476.49	6,643.19	166.70	2.6
200	60,000	8,362.71	8,529.41	166.70	2.0
200	80,000	10,248.93	10,415.63	166.70	1.6
200	100,000	12,135.15	12,301.85	166.70	1.4
500	100,000	16,086.15	16,492.85	406.70	2.5
500	150,000	20,801.70	21,208.40	406.70	2.0
500	200,000	25,517.25	25,923.95	406.70	1.6
500	250,000	30,232.80	30,639.50	406.70	1.3
750	150,000	24,094.20	24,700.90	606.70	2.5
750	225,000	31,167.53	31,774.23	606.70	1.9
750	300,000	38,240.85	38,847.55	606.70	1.6
750	375,000	45,314.18	45,920.88	606.70	1.3
1000	200,000	32,102.25	32,908.95	806.70	2.5
1000	300,000	41,533.35	42,340.05	806.70	1.9
1000	400,000	50,964.45	51,771.15	806.70	1.6
1000	500,000	60,395.55	61,202.25	806.70	1.3

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY

Monthly Billing Comparisons

SC2 General Primary Service - Winter

Demand (kW)	Monthly Usage (kWh)	Bill at Present Rates	Bill at Proposed Rates	Change Amount	Change Percent
100	20,000	$2,984.92	$3,060.62	$75.70	2.5
100	30,000	3,883.93	3,959.63	75.70	1.9
100	40,000	4,782.94	4,858.64	75.70	1.6
100	50,000	5,681.95	5,757.65	75.70	1.3
150	30,000	4,440.93	4,551.13	110.20	2.5
150	45,000	5,789.45	5,899.65	110.20	1.9
150	60,000	7,137.96	7,248.16	110.20	1.5
150	75,000	8,486.48	8,596.68	110.20	1.3
200	40,000	5,896.94	6,041.64	144.70	2.5
200	60,000	7,694.96	7,839.66	144.70	1.9
200	80,000	9,492.98	9,637.68	144.70	1.5
200	100,000	11,291.00	11,435.70	144.70	1.3
500	100,000	14,633.00	14,984.70	351.70	2.4
500	150,000	19,128.05	19,479.75	351.70	1.8
500	200,000	23,623.10	23,974.80	351.70	1.5
500	250,000	28,118.15	28,469.85	351.70	1.3
750	150,000	21,913.05	22,437.25	524.20	2.4
750	225,000	28,655.63	29,179.83	524.20	1.8
750	300,000	35,398.20	35,922.40	524.20	1.5
750	375,000	42,140.78	42,664.98	524.20	1.2
1000	200,000	29,193.10	29,889.80	696.70	2.4
1000	300,000	38,183.20	38,879.90	696.70	1.8
1000	400,000	47,173.30	47,870.00	696.70	1.5
1000	500,000	56,163.40	56,860.10	696.70	1.2

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY

Monthly Billing Comparisons

SC5 Residential with Space Heating

	Monthly Usage (kWh)	Bill at Present Rates	Bill at Proposed Rates	Change Amount	Change Percent
Summer					
	0	$4.53	$6.50	$1.97	43.5
	50	11.84	14.66	2.82	23.8
	100	19.15	22.82	3.67	19.2
	200	33.77	39.15	5.38	15.9
	250	41.08	47.31	6.23	15.2
	300	50.05	57.46	7.41	14.8
	400	68.00	77.75	9.75	14.3
	500	85.95	98.05	12.10	14.1
	750	123.53	140.32	16.79	13.6
	1,000	131.95	148.73	16.78	12.7
	1,500	148.77	165.56	16.79	11.3
	2,000	165.60	182.38	16.78	10.1
Winter					
	0	$4.53	$6.50	$1.97	43.5
	50	11.85	14.68	2.83	23.9
	100	19.18	22.85	3.67	19.1
	200	33.82	39.20	5.38	15.9
	250	41.15	47.38	6.23	15.1
	300	48.47	55.55	7.08	14.6
	400	63.11	71.90	8.79	13.9
	500	77.76	88.26	10.50	13.5
	750	108.74	122.64	13.90	12.8
	1,000	117.15	131.05	13.90	11.9
	1,500	133.97	147.88	13.91	10.4
	2,000	150.80	164.70	13.90	9.2

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY

Monthly Billing Comparisons
Service Classification No. 7

Annual Bill

Demand (kW)	Monthly Usage (kWh)	Percent Energy Split Peak	Off-Peak	Bill at Present Rates	Bill at Proposed Rates	Change Amount	Percent
1,000	300,000	35%	65%	$484,744	$502,647	17,903	3.7
1,000	300,000	50%	50%	487,147	505,050	17,903	3.7
1,000	400,000	35%	65%	581,534	599,438	17,904	3.1
1,000	400,000	50%	50%	584,738	602,642	17,904	3.1
2,000	600,000	35%	65%	966,939	1,002,295	35,356	3.7
2,000	600,000	50%	50%	971,745	1,007,101	35,356	3.6
2,000	800,000	35%	65%	1,160,519	1,195,875	35,356	3.0
2,000	800,000	50%	50%	1,166,927	1,202,283	35,356	3.0
3,000	900,000	35%	65%	1,449,135	1,501,942	52,807	3.6
3,000	900,000	50%	50%	1,456,344	1,509,151	52,807	3.6
3,000	1,200,000	35%	65%	1,739,505	1,792,313	52,808	3.0
3,000	1,200,000	50%	50%	1,749,117	1,801,925	52,808	3.0
4,000	1,200,000	35%	65%	1,931,330	2,001,590	70,260	3.6
4,000	1,200,000	50%	50%	1,940,942	2,011,202	70,260	3.6
4,000	1,600,000	35%	65%	2,318,490	2,388,750	70,260	3.0
4,000	1,600,000	50%	50%	2,331,306	2,401,566	70,260	3.0
5,000	1,500,000	35%	65%	2,413,525	2,501,237	87,712	3.6
5,000	1,500,000	50%	50%	2,425,540	2,513,252	87,712	3.6
5,000	2,000,000	35%	65%	2,897,476	2,985,188	87,712	3.0
5,000	2,000,000	50%	50%	2,913,496	3,001,208	87,712	3.0

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY

Monthly Billing Comparisons
Service Classification No. 7

Summer Bill

Demand (kW)	Monthly Usage (kWh)	Percent Energy Split Peak	Off-Peak	Bill at Present Rates	Bill at Proposed Rates	Change Amount	Percent
1,000	300,000	35%	65%	$40,915.97	$42,100.62	$1,184.65	2.9
1,000	300,000	50%	50%	41,116.22	42,300.87	1,184.65	2.9
1,000	400,000	35%	65%	48,981.81	50,166.46	1,184.65	2.4
1,000	400,000	50%	50%	49,248.81	50,433.46	1,184.65	2.4
2,000	600,000	35%	65%	81,619.59	83,951.24	2,331.65	2.9
2,000	600,000	50%	50%	82,020.09	84,351.74	2,331.65	2.8
2,000	800,000	35%	65%	97,751.27	100,082.92	2,331.65	2.4
2,000	800,000	50%	50%	98,285.27	100,616.92	2,331.65	2.4
3,000	900,000	35%	65%	122,323.21	125,801.86	3,478.65	2.8
3,000	900,000	50%	50%	122,923.96	126,402.61	3,478.65	2.8
3,000	1,200,000	35%	65%	146,520.73	149,999.38	3,478.65	2.4
3,000	1,200,000	50%	50%	147,321.73	150,800.38	3,478.65	2.4
4,000	1,200,000	35%	65%	163,026.83	167,652.48	4,625.65	2.8
4,000	1,200,000	50%	50%	163,827.83	168,453.48	4,625.65	2.8
4,000	1,600,000	35%	65%	195,290.19	199,915.84	4,625.65	2.4
4,000	1,600,000	50%	50%	196,358.19	200,983.84	4,625.65	2.4
5,000	1,500,000	35%	65%	203,730.45	209,503.10	5,772.65	2.8
5,000	1,500,000	50%	50%	204,731.70	210,504.35	5,772.65	2.8
5,000	2,000,000	35%	65%	244,059.65	249,832.30	5,772.65	2.4
5,000	2,000,000	50%	50%	245,394.65	251,167.30	5,772.65	2.4

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY

Monthly Billing Comparisons
Service Classification No. 7

Winter Bill

Demand (kW)	Monthly Usage (kWh)	Percent Energy Split Peak	Off-Peak	Bill at Present Rates	Bill at Proposed Rates	Change Amount	Percent
1,000	300,000	35%	65%	$40,134.97	$41,780.62	$1,645.65	4.1
1,000	300,000	50%	50%	40,335.22	41,980.87	1,645.65	4.1
1,000	400,000	35%	65%	48,200.81	49,846.46	1,645.65	3.4
1,000	400,000	50%	50%	48,467.81	50,113.46	1,645.65	3.4
2,000	600,000	35%	65%	80,057.59	83,311.24	3,253.65	4.1
2,000	600,000	50%	50%	80,458.09	83,711.74	3,253.65	4.0
2,000	800,000	35%	65%	96,189.27	99,442.92	3,253.65	3.4
2,000	800,000	50%	50%	96,723.27	99,976.92	3,253.65	3.4
3,000	900,000	35%	65%	119,980.21	124,841.86	4,861.65	4.1
3,000	900,000	50%	50%	120,580.96	125,442.61	4,861.65	4.0
3,000	1,200,000	35%	65%	144,177.73	149,039.38	4,861.65	3.4
3,000	1,200,000	50%	50%	144,978.73	149,840.38	4,861.65	3.4
4,000	1,200,000	35%	65%	159,902.83	166,372.48	6,469.65	4.0
4,000	1,200,000	50%	50%	160,703.83	167,173.48	6,469.65	4.0
4,000	1,600,000	35%	65%	192,166.19	198,635.84	6,469.65	3.4
4,000	1,600,000	50%	50%	193,234.19	199,703.84	6,469.65	3.3
5,000	1,500,000	35%	65%	199,825.45	207,903.10	8,077.65	4.0
5,000	1,500,000	50%	50%	200,826.70	208,904.35	8,077.65	4.0
5,000	2,000,000	35%	65%	240,154.65	248,232.30	8,077.65	3.4
5,000	2,000,000	50%	50%	241,489.65	249,567.30	8,077.65	3.3

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY

Monthly Billing Comparisons
Service Classification No. 7 - High Voltage Distribution

Annual Bill

Demand (kW)	Monthly Usage (kWh)	Percent Energy Split Peak	Off-Peak	Bill at Present Rates	Bill at Proposed Rates	Change Amount	Percent
1,000	300,000	35%	65%	$433,861	$440,889	7,028	1.6
1,000	300,000	50%	50%	434,142	441,170	7,028	1.6
1,000	400,000	35%	65%	514,913	521,941	7,028	1.4
1,000	400,000	50%	50%	515,287	522,315	7,028	1.4
2,000	600,000	35%	65%	840,265	854,321	14,056	1.7
2,000	600,000	50%	50%	840,826	854,882	14,056	1.7
2,000	800,000	35%	65%	1,002,368	1,016,424	14,056	1.4
2,000	800,000	50%	50%	1,003,116	1,017,172	14,056	1.4
3,000	900,000	35%	65%	1,246,668	1,267,752	21,084	1.7
3,000	900,000	50%	50%	1,247,511	1,268,595	21,084	1.7
3,000	1,200,000	35%	65%	1,489,823	1,510,907	21,084	1.4
3,000	1,200,000	50%	50%	1,490,946	1,512,030	21,084	1.4
4,000	1,200,000	35%	65%	1,653,072	1,681,184	28,112	1.7
4,000	1,200,000	50%	50%	1,654,195	1,682,307	28,112	1.7
4,000	1,600,000	35%	65%	1,977,278	2,005,390	28,112	1.4
4,000	1,600,000	50%	50%	1,978,776	2,006,888	28,112	1.4
5,000	1,500,000	35%	65%	2,059,476	2,094,616	35,140	1.7
5,000	1,500,000	50%	50%	2,060,880	2,096,020	35,140	1.7
5,000	2,000,000	35%	65%	2,464,733	2,499,873	35,140	1.4
5,000	2,000,000	50%	50%	2,466,605	2,501,745	35,140	1.4

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY

Monthly Billing Comparisons
Service Classification No. 7 - High Voltage Distribution

Summer Bill

Demand (kW)	Monthly Usage (kWh)	Percent Energy Split Peak	Off-Peak	Bill at Present Rates	Bill at Proposed Rates	Change Amount	Percent
1,000	300,000	35%	65%	$36,569.09	$36,794.09	$225.00	0.6
1,000	300,000	50%	50%	36,592.49	36,817.49	225.00	0.6
1,000	400,000	35%	65%	43,323.38	43,548.38	225.00	0.5
1,000	400,000	50%	50%	43,354.58	43,579.58	225.00	0.5
2,000	600,000	35%	65%	70,850.06	71,300.06	450.00	0.6
2,000	600,000	50%	50%	70,896.86	71,346.86	450.00	0.6
2,000	800,000	35%	65%	84,358.64	84,808.64	450.00	0.5
2,000	800,000	50%	50%	84,421.04	84,871.04	450.00	0.5
3,000	900,000	35%	65%	105,131.03	105,806.03	675.00	0.6
3,000	900,000	50%	50%	105,201.23	105,876.23	675.00	0.6
3,000	1,200,000	35%	65%	125,393.90	126,068.90	675.00	0.5
3,000	1,200,000	50%	50%	125,487.50	126,162.50	675.00	0.5
4,000	1,200,000	35%	65%	139,412.00	140,312.00	900.00	0.6
4,000	1,200,000	50%	50%	139,505.60	140,405.60	900.00	0.6
4,000	1,600,000	35%	65%	166,429.16	167,329.16	900.00	0.5
4,000	1,600,000	50%	50%	166,553.96	167,453.96	900.00	0.5
5,000	1,500,000	35%	65%	173,692.97	174,817.97	1,125.00	0.6
5,000	1,500,000	50%	50%	173,809.97	174,934.97	1,125.00	0.6
5,000	2,000,000	35%	65%	207,464.42	208,589.42	1,125.00	0.5
5,000	2,000,000	50%	50%	207,620.42	208,745.42	1,125.00	0.5

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY

Monthly Billing Comparisons
Service Classification No. 7 - High Voltage Distribution

Winter Bill

Demand (kW)	Monthly Usage (kWh)	Percent Energy Split Peak	Off-Peak	Bill at Present Rates	Bill at Proposed Rates	Change Amount	Percent
1,000	300,000	35%	65%	$35,948.09	$36,714.09	$766.00	2.1
1,000	300,000	50%	50%	35,971.49	36,737.49	766.00	2.1
1,000	400,000	35%	65%	42,702.38	43,468.38	766.00	1.8
1,000	400,000	50%	50%	42,733.58	43,499.58	766.00	1.8
2,000	600,000	35%	65%	69,608.06	71,140.06	1,532.00	2.2
2,000	600,000	50%	50%	69,654.86	71,186.86	1,532.00	2.2
2,000	800,000	35%	65%	83,116.64	84,648.64	1,532.00	1.8
2,000	800,000	50%	50%	83,179.04	84,711.04	1,532.00	1.8
3,000	900,000	35%	65%	103,268.03	105,566.03	2,298.00	2.2
3,000	900,000	50%	50%	103,338.23	105,636.23	2,298.00	2.2
3,000	1,200,000	35%	65%	123,530.90	125,828.90	2,298.00	1.9
3,000	1,200,000	50%	50%	123,624.50	125,922.50	2,298.00	1.9
4,000	1,200,000	35%	65%	136,928.00	139,992.00	3,064.00	2.2
4,000	1,200,000	50%	50%	137,021.60	140,085.60	3,064.00	2.2
4,000	1,600,000	35%	65%	163,945.16	167,009.16	3,064.00	1.9
4,000	1,600,000	50%	50%	164,069.96	167,133.96	3,064.00	1.9
5,000	1,500,000	35%	65%	170,587.97	174,417.97	3,830.00	2.2
5,000	1,500,000	50%	50%	170,704.97	174,534.97	3,830.00	2.2
5,000	2,000,000	35%	65%	204,359.42	208,189.42	3,830.00	1.9
5,000	2,000,000	50%	50%	204,515.42	208,345.42	3,830.00	1.9

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY

Summary of Total Revenue Impacts

Service Classification	Total Sales (MWh)	Total Current Revenue ($000s)	Total Proposed Revenue ($000s)	Change ($000s)	Percent Change
SC1 Res Svc & SC5 Res Sp	699,591	$112,895.7	$126,700.8	$13,805.1	12.2%
SC2 Sec Non Dmd Billed	6,327	980.9	1,089.6	108.8	11.1%
SC2 Sec Dmd Billed	478,653	59,828.9	64,572.9	4,743.9	7.9%
SC2 Space Heating	21,151	2,468.1	2,723.1	255.0	10.3%
SC2 Pri	70,292	7,274.6	7,391.1	116.5	1.6%
SC3 Res TOD Heating	242	32.5	36.5	4.0	12.5%
SC4 Public Street Lighting	5,727	1,139.3	1,356.3	217.0	19.0%
SC6 POL - Dusk to Dawn	3,461	618.7	783.8	165.1	26.7%
SC6 POL - Energy Only	2,085	243.0	272.0	28.9	11.9%
SC7 Pri	168,027	17,805.6	18,171.9	366.2	2.1%
SC7 High Voltage	53,934	3,716.6	3,733.6	17.0	0.5%
SC7 Space Heating	5,731	587.5	666.5	79.1	13.5%
	1,515,224	$207,591.4	$227,498.0	$19,906.6	9.6%

Proposed Revenue Requirement	$19,906.0
Over/(Under)	$0.6

Note:
An estimated electric supply charge for retail access customers has been included in total revenues.

ROCKLAND ELECTRIC COMPANY

Analysis of the Impacts of Combining the Rate Structures of Service Classification Nos. 1 and 5

ROCKLAND ELECTRIC COMPANY

Analysis of the Impacts of Combining the Rate Structures of Service Classification Nos. 1 and 5

Purpose

In Rockland Electric Company's (the "Company") last base rate case (Docket No. ER16050428), the Company presented to the New Jersey Board of Public Utilities ("BPU") the impacts of modifying the Service Classification ("SC") No. 5 rate structure from a three block rate structure in the summer and a two block rate structure in the winter to a two block rate structure in the summer and a flat rate structure in the winter. The proposal was made to begin the process of moving all SC No. 5 customers to SC No. 1 since the special rates for SC No. 5 space heating customers have no cost basis and do not promote statewide energy objectives. In its Order Approving Stipulation, dated February 22, 2017, the BPU approved the Company's proposal. In this analysis the Company analyzes the impacts setting equal the block rates paid by SC No. 1 and SC No. 5 customers.

Background on Service Classification No. 5

SC No. 5 is applicable to residential customers with space heating subject to the following conditions: (1) the electric resistance heating equipment is supplementary to a heat pump system, energy storage system, or a system for which a renewable resource is the primary energy input; or (2) the customer establishes that heating requirements are seasonal in nature and electric resistance is the most economic heat source for the customer.

SC No. 5 customers are billed under a two block rate structure for kWh usage. The two blocks include: (1) usage less than or equal to 600 kWh; and (2) usage in excess of 600 kWh. In the winter, the rate is the same for the first and second block.

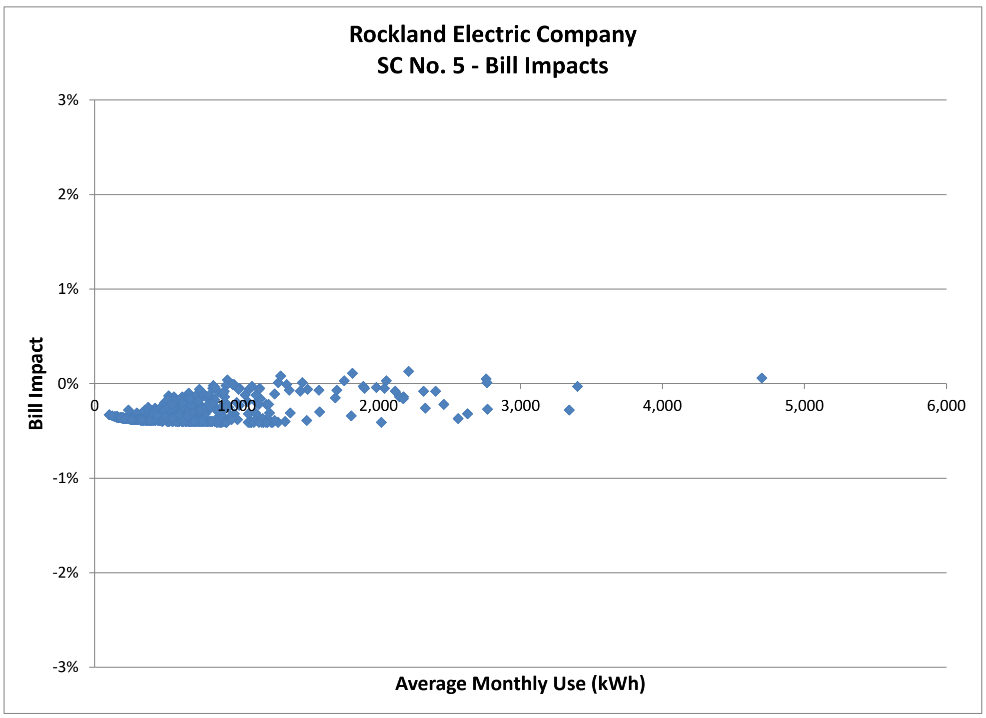
Analysis of Impacts

Aligning the block rates for SC No. 5 with SC No. 1 can produce customer bill impacts depending on individual customer usage characteristics. For purposes of reviewing bill impacts, historic customer-specific billing data was prepared for each group based on the 12 months ended March 2019. These data sets were limited to include only customers with 10 months or more of billing data. This eliminated outlier customers with several months' worth of incomplete billing information. Monthly bills were calculated at current and revised distribution rates reflecting revenue neutral transition scenarios. To limit customer bill impacts, the Company decided that revenue neutral transition scenarios should generally not produce customer bill impacts greater than 5 percent on a total bill basis. The Company's findings are described below.

Combining the Rate Structures of Service Classification No. 5 and Service Classification No. 1

The intent of the Company is to combine the rate structures of SC No. 5 with SC No. 1. As the current kWh blocks for SC No. 5 and SC No. 1 are equal, the Company first summed both of the classes historic billing units and resulting revenues, by season, for (1) usage less than or equal to 600 kWh; and (2) usage in excess of 600 kWh. Resulting revenues of the combined classes were then divided by the combined billing units to calculate the resulting revenue neutral rate for each seasonal kWh block. When the Company compared these rates to the current SC No. 5 rates, it noticed rate decreases for every kWh block rate except the summer[1] usage block in excess of 600 kWh.

The graph below depicts annualized total bill impacts of combining the rate structures of SC No. 5 with that of SC No. 1:



As shown in the graph above, the entire SC No. 5 class shows relatively minor, and mostly negative, bill impacts.

Summary of Proposal

Based on the above analysis, the Company proposes to combine the block rate structure of SC No. 5 with that of SC No. 1.

[1] Definition of Summer Billing Months - June through September

Attachment A to this Exhibit contains monthly billing comparison reflecting this proposal.

Exhibit P-5
Schedule 5
Attachment A

Rockland Electric Company

Monthly Billing Comparisons

Analysis of Combining the Rate Structures of
Service Classification No. 5 and Service Classification No. 1

SC No. 5 - Residential Space Heating

100% Transition to SC No. 1 Rates

	Monthly Usage (kWh)	Bill At Present Rates	Bill At Proposed Rates	Change Amount	%
SUMMER					
	0	$4.25	$4.25	$0.00	0.0
	100	18.77	18.71	-0.06	-0.3
	200	33.29	33.17	-0.12	-0.4
	300	47.81	47.62	-0.18	-0.4
	400	62.32	62.08	-0.24	-0.4
	500	76.84	76.54	-0.30	-0.4
	750	118.05	117.85	-0.20	-0.2
	1,000	162.52	162.60	0.07	0.0
	1,250	207.00	207.34	0.34	0.2
	2000	340.43	341.59	1.16	0.3
	3000	518.34	520.58	2.25	0.4
	5000	874.15	878.57	4.43	0.5
WINTER					
	0	4.25	4.25	0.00	0.0
	100	18.80	18.74	-0.06	-0.3
	200	33.34	33.22	-0.12	-0.4
	300	47.89	47.71	-0.18	-0.4
	400	62.44	62.19	-0.24	-0.4
	500	76.98	76.68	-0.30	-0.4
	750	113.35	112.90	-0.45	-0.4
	1,000	149.72	149.11	-0.61	-0.4
	1,250	186.08	185.33	-0.76	-0.4
	2000	295.18	293.97	-1.21	-0.4
	3000	440.65	438.83	-1.82	-0.4
	5000	731.58	728.55	-3.03	-0.4

ROCKLAND ELECTRIC COMPANY

Analysis of the Impacts of Eliminating Block Usage Rates and Shifting Usage Revenue to Demand Revenue in Service Classification No. 2 – Secondary Demand Billed

ROCKLAND ELECTRIC COMPANY

Analysis of the Impacts of Eliminating
Block Usage Rates and Shifting Usage Revenue to Demand Revenue in Service Classification No. 2 – Secondary Demand Billed

Purpose

In Rockland Electric Company's (the "Company") prior two base rate cases (Docket Nos. ER1311135 and ER16050428), the Company presented to the New Jersey Board of Public Utilities ("BPU") the impacts of eliminating 33 percent of the current usage rate differentials and eliminating the corresponding demand rate differentials for Service Classification ("SC") No. 2 - Secondary Demand Billed customers. In its Order Approving Stipulation, in each case, the BPU approved the Company's proposals. In this analysis the Company analyzes the impacts of further transitioning the SC No. 2 - Secondary Demand Billed customer class from its current declining block rate structure for usage, measured in kWh, to a single or "flat" per kWh rate. The Company also analyzes the impacts of reallocating revenue from usage to demand charges for these customers. This analysis discusses the main considerations in transitioning the rate structure for SC No. 2 – Secondary Demand Billed customers and is used for proposing revenue-neutral changes to this customer group prior to applying the rate increases proposed by the Company in its base rate increase proposal.

Background on Service Classification No. 2

SC No. 2 - Secondary Demand Billed customers are billed under a declining two block rate structure for usage and an inclining two block rate structure for demand, both of which are seasonally differentiated. The two kWh blocks include: (1) usage less than or equal to the first 4,920 kWh, and (2) usage in excess of 4,920 kWh. The two kW blocks include: (1) demand less than or equal to the first 5 kW, and (2) demand in excess of 5 kW. This transition to flat rates should help to simplify bills for these customers by making them easier to comprehend while still promoting efficient system utilization.

Analysis of Impacts

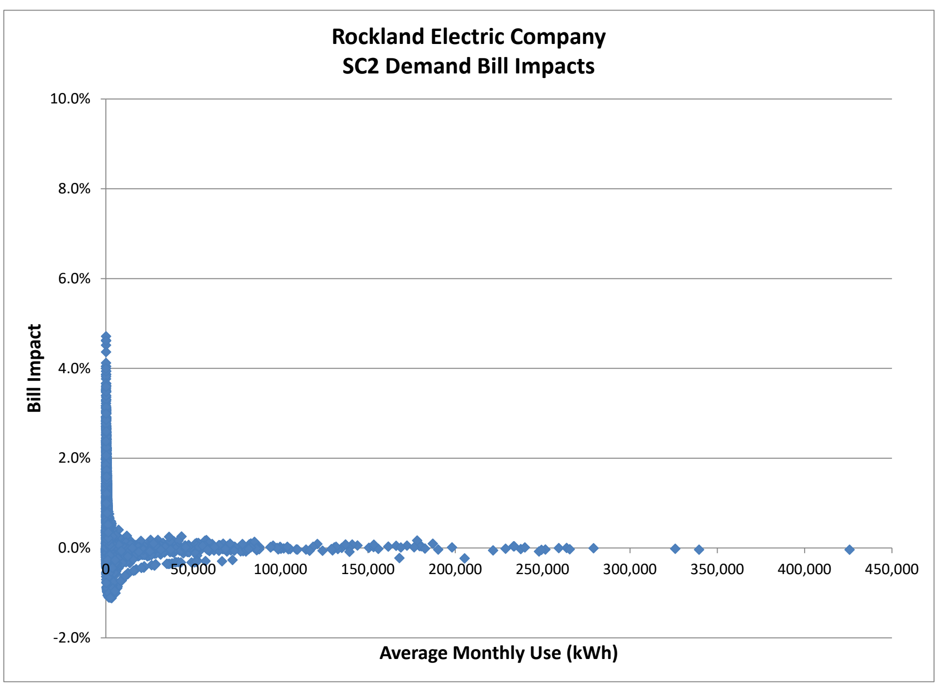
Both a transition from declining block to flat usage rates and shifting revenue from usage to demand can produce significant customer bill impacts depending on individual customer usage characteristics. Therefore, the Company analyzed the customer impacts associated with various revenue neutral scenarios for making this transition. Also, please note that, in a transition to flat usage rates, the usage rate for the first block will decline and the resulting decrease in usage revenue must be offset by increased demand revenue for the first 5 kW. Therefore, the transition to flat usage rates will inherently be accompanied by a transition to flat demand rates.

For purposes of reviewing bill impacts, historic customer-specific billing data was prepared for the SC No. 2 – Secondary Demand Billed group based on the 12 months ended March 2019. The data set was limited to include only customers with 10 months or more of billing data. This eliminated outlier customers with several months' worth of incomplete billing information. Bills were calculated at current rates and at revised rates reflecting revenue neutral transition scenarios above. To limit customer bill impacts, the Company decided that the revenue neutral transition scenarios should generally not produce customer bill impacts greater than 5 percent on a total bill basis. The Company's findings are described below.

The Company first analyzed the effects of transition to flat usage rates for the SC No. 2 - Secondary Demand Billed group. This group is comprised of a diverse set of customers with usage that is within two usage blocks. In general, customers with relatively less usage (e.g., usage in the first 4,920 kWh block) would pay lower usage rates under a transition to flat usage rates. Similarly, customers with more usage in the second rate block would pay higher second block usage rates under a transition to flat rates. Also, as discussed previously, any transition to flat usage rates must be accompanied by a transition to flat demand rates. This would increase the demand charges for the first 5 kW, while decreasing demand charges for demands greater than 5 kW. Customers with low demands would experience demand charge increases due to the increased first block demand charges, and customers with high demands would experience a decrease in demand charges.

The Company then analyzed the results of reallocating a portion of revenue from usage to demand. This reallocation from usage to demand charges is appropriate given that distribution costs are primarily demand related.

The graph below shows the bill impacts of both a) reducing the differentials in usage charges by 25 percent, while proportionately adjusting for a transition to increased first block demand charges; and b) shifting 2 percent of the revenue from usage charges to demand charges.



As shown in the graph above, this group has a range of bill impacts from bill decreases of 1.1 percent to bill increases of approximately 4.7 percent. The most significant variability appears in the impacts on low usage customers. These customers use electricity primarily in the first usage block, but the savings in a transition to flat usage rates is more than offset by both the increase in first block demand charges and the shift in revenue from usage to demand. However, it should be noted that zero customers in the analysis group exceeded the 5 percent threshold.

Summary of Proposal

In order to make progress towards a transition to flat rates, better align rates with cost causation and to limit the bill impacts to the majority of the population, the Company proposes to a) reduce usage rate differentials by 25 percent with corresponding reductions in the demand block differentials; and b) shift 2 percent of the revenue from usage charges to demand charges.

Attachment A to this Exhibit contains monthly billing comparisons reflecting these proposals.

Rockland Electric Company

Monthly Billing Comparisons

Analysis of the Impacts of Eliminating
Block Usage Rates and Shifting Usage Revenue to Demand Revenue
in Service Classification No. 2 - Secondary

SC2 Secondary Demand Billed - Summer

25% Transition to Flat Usage Rates
2% Transfer of Usage Revenue to Demand

Monthly Usage (kWh)	Demand (kW)	Bill At Present Rates	Bill At Proposed Rates	Change Amount	Change %
700	7	$142.84	$144.69	$1.85	1.3
1,400	7	223.30	224.12	0.83	0.4
2,100	7	303.75	303.56	-0.20	-0.1
2,800	7	384.21	382.99	-1.22	-0.3
1,000	10	210.59	212.35	1.76	0.8
2,000	10	325.53	325.82	0.29	0.1
3,000	10	440.47	439.30	-1.17	-0.3
4,000	10	555.41	552.78	-2.63	-0.5
2,500	25	549.35	550.63	1.28	0.2
5,000	25	836.28	834.01	-2.27	-0.3
7,500	25	1,110.66	1,107.97	-2.68	-0.2
10,000	25	1,385.03	1,381.93	-3.10	-0.2
5,000	50	1,113.53	1,114.12	0.59	0.1
10,000	50	1,662.28	1,662.05	-0.23	0.0
15,000	50	2,211.03	2,209.97	-1.06	0.0
20,000	50	2,759.78	2,757.89	-1.89	-0.1
10,000	100	2,216.78	2,222.27	5.49	0.2
20,000	100	3,314.28	3,318.12	3.84	0.1
30,000	100	4,411.78	4,413.96	2.19	0.0
40,000	100	5,509.27	5,509.81	0.54	0.0
15,000	150	3,320.03	3,330.42	10.39	0.3
30,000	150	4,966.28	4,974.19	7.91	0.2
45,000	150	6,612.52	6,617.96	5.44	0.1
60,000	150	8,258.77	8,261.73	2.96	0.0

Rockland Electric Company

Monthly Billing Comparisons

Analysis of the Impacts of Eliminating
Block Usage Rates and Shifting Usage Revenue to Demand Revenue
in Service Classification No. 2 - Secondary

SC2 Secondary Demand Billed - Winter

25% Transition to Flat Usage Rates
2% Transfer of Usage Revenue to Demand

Monthly Usage (kWh)	Demand (kW)	Bill At Present Rates	Bill At Proposed Rates	Change Amount	Change %
700	7	$130.56	$132.13	$1.57	1.2
1,400	7	206.51	207.27	0.76	0.4
2,100	7	282.47	282.41	-0.06	0.0
2,800	7	358.43	357.56	-0.87	-0.2
1,000	10	191.01	192.49	1.48	0.8
2,000	10	299.52	299.84	0.32	0.1
3,000	10	408.03	407.19	-0.84	-0.2
4,000	10	516.54	514.53	-2.01	-0.4
2,500	25	493.27	494.32	1.05	0.2
5,000	25	764.26	762.47	-1.79	-0.2
7,500	25	1,026.38	1,023.97	-2.41	-0.2
10,000	25	1,288.50	1,285.47	-3.03	-0.2
5,000	50	996.76	997.15	0.39	0.0
10,000	50	1,521.00	1,520.16	-0.85	-0.1
15,000	50	2,045.25	2,043.16	-2.09	-0.1
20,000	50	2,569.50	2,566.17	-3.33	-0.1
10,000	100	1,986.00	1,989.52	3.51	0.2
20,000	100	3,034.50	3,035.53	1.03	0.0
30,000	100	4,083.00	4,081.54	-1.45	0.0
40,000	100	5,131.50	5,127.56	-3.94	-0.1
15,000	150	2,975.25	2,981.89	6.63	0.0
30,000	150	4,548.00	4,550.91	2.91	0.0
45,000	150	6,120.74	6,119.92	-0.82	0.0
60,000	150	7,693.49	7,688.94	-4.55	0.0

Rockland Electric Company
Summary of New Service Classification Nos. 4 and 6 Luminaires

New LED Street Lighting Luminaires (applicable to SC No. 4 and SC No. 6)

	23 Watt 3000 Lumen Class L.E.D.	35 Watt 3900 Lumen Class L.E.D.	50 Watt 5000 Lumen Class L.E.D.	68 Watt 7250 Lumen Class L.E.D.	103 Watt 12000 Lumen Class L.E.D.	140 Watt 16000 Lumen Class L.E.D.	200 Watt 22000 Lumen Class L.E.D.
Fixture	$6.40	$6.25	$6.27	$6.59	$7.57	$8.00	$12.33
Arm and Wire	1.30	1.30	1.30	1.30	1.30	1.30	1.30
Total Monthly Luminaire Charge	$7.70	$7.55	$7.57	$7.89	$8.87	$9.30	$13.63
Total Monthly Luminaire Charge (w SUT)	**$8.21**	**$8.05**	**$8.07**	**$8.41**	**$9.46**	**$9.92**	**$14.53**

New LED Flood Lighting Luminaires (applicable to SC No. 4 and SC No. 6)

	125 Watt 15,500 Lumen Class L.E.D.	205 Watt 27,000 Lumen Class L.E.D.	290 Watt 37,500 Lumen Class L.E.D.
Fixture	$9.42	$12.37	$13.59
Arm and Wire	1.30	1.30	1.30
Total Monthly Luminaire Charge	$10.72	$13.67	$14.89
Total Monthly Luminaire Charge (w SUT)	**$11.43**	**$14.58**	**$15.88**

New LED Power Bracket Luminaires (applicable to SC No. 6)

	35 Watt 3,950 Lumen Class L.E.D.	50 Watt 5,550 Lumen Class L.E.D.	65 Watt 7,350 Lumen Class L.E.D.
Fixture	$5.80	$5.90	$5.97
Arm and Wire	1.30	1.30	1.30
Total Monthly Luminaire Charge	$7.10	$7.20	$7.27
Total Monthly Luminaire Charge (w SUT)	**$7.57**	**$7.68**	**$7.75**

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 1

		Present		Proposed	
		Summer	Winter	Summer	Winter
Customer Charge:	per month	$4.53	$4.53	$6.50	$6.50
Distribution Charge:					
First 600 kWh	¢ per kWh	4.394	4.394	6.064	6.064
Over 600 kWh	¢ per kWh	5.537	4.394	7.638	6.064
Transmission Charge (incl Trans Surch):					
All kWh	¢ per kWh	3.345	3.345	3.345	3.345
RGGI Surcharge	¢ per kWh	0.0921	0.0921	0.0921	0.0921
Societal Benefits Charge	¢ per kWh	0.6050	0.6050	0.6050	0.6050
Securitization Charges:					
TBC	¢ per kWh	0.276	0.276	0.276	0.276
TBC-Tax	¢ per kWh	0.052	0.052	0.052	0.052
Total	¢ per kWh	0.328	0.328	0.328	0.328
Temporary Tax Act Credit	¢ per kWh	(0.235)	(0.235)	(0.235)	(0.235)
ZEC Recovery Charge	¢ per kWh	0.400	0.400	0.400	0.400
Basic Generation Service:					
First 600 kWh	¢ per kWh	6.474	8.382	6.474	8.382
Over 600 kWh	¢ per kWh	9.835	8.382	9.835	8.382
Reconciliation Charge	¢ per kWh	Variable	Variable	Variable	Variable
Minimum Charge:					
Monthly	monthly	$4.53		$6.50	
Per Contract	per contract	$27.18		$39.00	

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 2
Secondary Demand Billed

		Present		Proposed	
		Summer	Winter	Summer	Winter
Customer Charge:	per month	$16.37	$16.37	$21.01	$21.01
Distribution Charge:					
Demand Charge					
First 5 kW	per kW	$1.76	$1.47	$4.69	$3.92
Over 5 kW	per kW	3.53	2.99	7.39	6.23
Usage Charge					
First 4,920 kWh	¢ per kWh	3.427	3.212	3.271	3.088
Over 4,920 kWh	¢ per kWh	2.874	2.821	2.856	2.795
Transmission Charge (incl Trans Surch):					
Demand Charge					
All kW	per kW	$1.41	$1.18	$1.41	$1.18
Usage Charge					
All kWh	¢ per kWh	1.105	1.105	1.105	1.105
RGGI Surcharge	¢ per kWh	0.0921	0.0921	0.0921	0.0921
Societal Benefits Charge	¢ per kWh	0.6050	0.6050	0.6050	0.6050
Securitization Charges:					
TBC	¢ per kWh	0.276	0.276	0.276	0.276
TBC-Tax	¢ per kWh	0.052	0.052	0.052	0.052
Total	¢ per kWh	0.328	0.328	0.328	0.328
Temporary Tax Act Credit	¢ per kWh	(0.2350)	(0.2350)	(0.2350)	(0.2350)
ZEC Recovery Charge	¢ per kWh	0.4000	0.4000	0.4000	0.4000

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 2
Secondary Demand Billed (Continued)

Basic Generation Service: (Non-CIEP Billed)		Present Summer	Present Winter	Proposed Summer	Proposed Winter
Demand Charge					
First 5 kW	per kW	$1.81	$1.48	$1.81	$1.48
Over 5 kW	per kW	6.27	5.23	6.27	5.23
Usage Charge					
First 4,920 kWh	¢ per kWh	5.651	5.210	5.651	5.210
Reconciliation Charge	¢ per kWh	Variable	Variable	Variable	Variable
Minimum Charge:		$16.37	plus the demand charge	$21.01	plus the demand charge

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 2
Secondary Non-Demand Billed - Metered

		Present		Proposed	
		Summer	Winter	Summer	Winter
Customer Charge:	per month	$12.26	$12.26	$16.00	$16.00
Distribution Charge:					
Usage Charge					
All kWh	¢ per kWh	3.511	3.182	3.499	3.171
Transmission Charge (incl Trans Surch):					
Usage Charge					
All kWh	¢ per kWh	1.105	1.105	1.105	1.105
RGGI Surcharge	¢ per kWh	0.0921	0.0921	0.0921	0.0921
Societal Benefits Charge	¢ per kWh	0.6050	0.6050	0.6050	0.6050
Securitization Charges:					
TBC	¢ per kWh	0.276	0.276	0.276	0.276
TBC-Tax	¢ per kWh	0.052	0.052	0.052	0.052
Total	¢ per kWh	0.328	0.328	0.328	0.328
Temporary Tax Act Credit	¢ per kWh	(0.2350)	(0.2350)	(0.2350)	(0.2350)
ZEC Recovery Charge	¢ per kWh	0.4000	0.4000	0.4000	0.4000
Basic Generation Service:					
Usage Charge					
All kWh	¢ per kWh	7.358	6.425	7.358	6.425
Reconciliation Charge	¢ per kWh	Variable	Variable	Variable	Variable
Minimum Charge:		$12.26		$16.00	

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 2
Secondary Non-Demand Billed - Unmetered

		Present		Proposed	
		Summer	Winter	Summer	Winter
Customer Charge:	per month	$10.57	$10.57	$14.00	$14.00
Distribution Charge:					
Usage Charge					
All kWh	¢ per kWh	3.511	3.182	3.499	3.171
Transmission Charge (incl Trans Surch):					
Usage Charge					
All kWh	¢ per kWh	1.105	1.105	1.105	1.105
RGGI Surcharge	¢ per kWh	0.0921	0.0921	0.0921	0.0921
Societal Benefits Charge	¢ per kWh	0.6050	0.6050	0.6050	0.6050
Securitization Charges:					
TBC	¢ per kWh	0.276	0.276	0.276	0.276
TBC-Tax	¢ per kWh	0.052	0.052	0.052	0.052
Total	¢ per kWh	0.328	0.328	0.328	0.328
Temporary Tax Act Credit	¢ per kWh	(0.2350)	(0.2350)	(0.2350)	(0.2350)
ZEC Recovery Charge	¢ per kWh	0.4000	0.4000	0.4000	0.4000
Basic Generation Service:					
Usage Charge					
All kWh	¢ per kWh	7.358	6.425	7.358	6.425
Reconciliation Charge	¢ per kWh	Variable	Variable	Variable	Variable
Minimum Charge:		$10.57		$14.00	

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 2
Space Heating

		Present		Proposed	
		Summer	Winter	Summer	Winter
Distribution Charge:					
Usage Charge					
All kWh	¢ per kWh	4.478	2.688	6.662	3.998
Transmission Charge (incl Trans Surch):					
All kWh	¢ per kWh	1.105	1.105	1.105	1.105
RGGI Surcharge	¢ per kWh	0.0921	0.0921	0.0921	0.0921
Societal Benefits Charge	¢ per kWh	0.6050	0.6050	0.6050	0.6050
Securitization Charges:					
TBC	¢ per kWh	0.276	0.276	0.276	0.276
TBC-Tax	¢ per kWh	0.052	0.052	0.052	0.052
Total	¢ per kWh	0.328	0.328	0.328	0.328
Temporary Tax Act Credit	¢ per kWh	(0.2350)	(0.2350)	(0.2350)	(0.2350)
ZEC Recovery Charge	¢ per kWh	0.4000	0.4000	0.4000	0.4000
Basic Generation Service:					
Usage Charge					
All kWh	¢ per kWh	7.358	6.425	7.358	6.425
Reconciliation Charge	¢ per kWh	Variable	Variable	Variable	Variable

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 2
Primary

		Present		Proposed	
		Summer	Winter	Summer	Winter
Customer Charge:	per month	$85.30	$85.30	$92.00	$92.00
Distribution Charge:					
Demand Charge					
All kW	per kW	$6.90	$5.91	$4.71	$4.03
Usage Charge					
All kWh	¢ per kWh	1.485	1.485	1.485	1.485
Transmission Charge (incl Trans Surch):					
Demand Charge					
All kW	per kW	$1.41	$1.27	$1.41	$1.27
Usage Charge					
All kWh	¢ per kWh	1.105	1.105	1.105	1.105
RGGI Surcharge	¢ per kWh	0.0921	0.0921	0.0921	0.0921
Societal Benefits Charge	¢ per kWh	0.6050	0.6050	0.6050	0.6050
Securitization Charges:					
TBC	¢ per kWh	0.276	0.276	0.276	0.276
TBC-Tax	¢ per kWh	0.052	0.052	0.052	0.052
Total	¢ per kWh	0.328	0.328	0.328	0.328
Temporary Tax Act Credit	¢ per kWh	(0.2350)	(0.2350)	(0.2350)	(0.2350)
ZEC Recovery Charge	¢ per kWh	0.4000	0.4000	0.4000	0.4000

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 2
Primary (Continued)

Basic Generation Service: (Non-CIEP Billed)		Present Summer	Present Winter	Proposed Summer	Proposed Winter
Demand Charge					
First 5 kW	per kW	$1.81	$1.48	$1.81	$1.48
Over 5 kW	per kW	6.27	5.23	6.27	5.23
Usage Charge					
All kWh	¢ per kWh	5.651	5.210	5.651	5.210
Reconciliation Charge	¢ per kWh	Variable	Variable	Variable	Variable
Minimum Charge:		$85.30	plus the demand charge	$92.00	plus the demand charge

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 3

		Present		Proposed	
		Summer	Winter	Summer	Winter
Customer Charge:	per month	$6.50	$6.50	$9.00	$9.00
Distribution Charge:					
All kWh, Monday to Friday, 10 A.M. to 10 P.M.	¢ per kWh	6.009	5.391	10.127	9.084
All Other kWh	¢ per kWh	2.164	2.164	3.648	3.648
Transmission Charge (incl Trans Surch):					
All kWh	¢ per kWh	2.122	2.122	2.122	2.122
RGGI Surcharge	¢ per kWh	0.0921	0.0921	0.0921	0.0921
Societal Benefits Charge	¢ per kWh	0.6050	0.6050	0.6050	0.6050
Securitization Charges:					
TBC	¢ per kWh	0.276	0.276	0.276	0.276
TBC-Tax	¢ per kWh	0.052	0.052	0.052	0.052
Total	¢ per kWh	0.328	0.328	0.328	0.328
Temporary Tax Act Credit	¢ per kWh	(0.2350)	(0.2350)	(0.2350)	(0.2350)
ZEC Recovery Charge	¢ per kWh	0.4000	0.4000	0.4000	0.4000
Basic Generation Service:					
All kWh, Monday to Friday, 10 A.M. to 10 P.M.	¢ per kWh	12.362	9.788	12.362	9.788
All Other kWh	¢ per kWh	5.113	5.019	5.113	5.019
Reconciliation Charge	¢ per kWh	Variable	Variable	Variable	Variable
Minimum Charge:					
The Customer Charge, not less than		$78.00	per contract.	$108.00	per contract.

*All Rates Include Sales and Use Tax

Service Classification No. 4

Luminaries Charge, per month

Nominal Lumens	Luminaires Type	Watts	Total Wattage	Present Distribution Charge	Proposed Distribution Charge
Street Lighting Luminaires					
5,800	Sodium Vapor	70	108	$7.60	$8.89
9,500	Sodium Vapor	100	142	8.25	9.66
16,000	Sodium Vapor	150	199	10.04	11.75
27,500	Sodium Vapor	250	311	12.82	15.00
46,000	Sodium Vapor	400	488	20.79	24.33
3,000	LED	20-25	23	N/A	8.21
3,900	LED	30-39	35	N/A	8.05
5,000	LED	40-59	50	N/A	8.07
7,250	LED	60-79	68	N/A	8.41
12,000	LED	95-110	103	N/A	9.46
16,000	LED	130-150	140	N/A	9.92
22,000	LED	180-220	200	N/A	14.53
LED Flood Lighitng Luminaires					
15,500	LED	115-130	125	N/A	$11.43
27,000	LED	175-225	205	N/A	14.58
37,500	LED	265-315	290	N/A	15.88

The following luminaires will no longer be installed. Charges are for existing luminaires only.

Nominal Lumens	Luminaires Type	Watts	Total Wattage	Present Distribution Charge	Proposed Distribution Charge
Post Top Luminaries					
16,000	Sodium Vapor-Offset	150	199	$20.29	$23.75
Street Lighting Luminaires					
1,000	Open Bottom Inc	92	92	$5.03	$5.89
4,000	Mercury Vapor	100	127	6.81	7.98
7,900	Mercury Vapor	175	211	8.03	9.39
12,000	Mercury Vapor	250	296	10.44	12.22
22,500	Mercury Vapor	400	459	13.25	15.51
40,000	Mercury Vapor	700	786	20.15	23.59
59,000	Mercury Vapor	1,000	1,105	25.47	29.81

Service Classification No. 4 (Continued)

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Nominal Lumens	Luminaires Type	Watts	Total Wattage	Present Distribution Charge		Proposed Distribution Charge	
Street Lighting Luminaires (Continued)							
3,400	Induction	40	45	$7.95		$9.31	
5,950	Induction	70	75	8.10		9.48	
8,500	Induction	100	110	9.15		10.71	
5,890	LED	70	74	8.71		10.19	
9,365	LED	100	101	10.69		12.52	
Post-Top Luminaires							
4,000	Mercury Vapor	100	130	$10.36		$12.13	
7,900	Mercury Vapor	175	215	12.70		14.86	
7,900	Mercury Vapor – Off-Set	175	215	14.92		17.45	
Additional Charge:							
UG Svc- Company owned and maintained -				$17.35	per mo.	$20.30	per mo.
UG Svc- Customer owned and maintained -				$4.22	per mo.	$4.94	per mo.
15 Foot Brackets				$0.47	per mo.	$0.54	per mo.
Transmission Charge (incl Trans Surch):				1.2240	¢ per kWh	1.2240	¢ per kWh
RGGI Surcharge				0.0921	¢ per kWh	0.0921	¢ per kWh
Societal Benefits Charge				0.6050	¢ per kWh	0.6050	¢ per kWh
Securitization Charges:							
TBC				0.276	¢ per kWh	0.276	¢ per kWh
TBC-Tax				0.052	¢ per kWh	0.052	¢ per kWh
Total				0.328	¢ per kWh	0.328	¢ per kWh
Temporary Tax Act Credit				(0.235)	¢ per kWh	(0.235)	¢ per kWh
ZEC Recovery Surcharge				0.400	¢ per kWh	0.400	¢ per kWh
Basic Generation Service:							
Summer				5.113	¢ per kWh	5.113	¢ per kWh
Winter				5.019	¢ per kWh	5.019	¢ per kWh
Reconciliation Charge				Variable	¢ per kWh	Variable	¢ per kWh

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 5

		Present		Proposed	
		Summer	Winter	Summer	Winter
Customer Charge:	per month	$4.53	$4.53	$6.50	$6.50
Distribution Charge:					
First 600 kWh	¢ per kWh	4.460	4.460	6.064	6.064
Over 600 kWh	¢ per kWh	5.420	4.460	7.638	6.064
Transmission Charge (incl Trans Surch):					
All kWh	¢ per kWh	2.175	2.175	2.175	2.175
RGGI Surcharge	¢ per kWh	0.0921	0.0921	0.0921	0.0921
Societal Benefit Charge	¢ per kWh	0.6050	0.6050	0.6050	0.6050
Securitization Charges:					
TBC	¢ per kWh	0.276	0.276	0.276	0.276
TBC-Tax	¢ per kWh	0.052	0.052	0.052	0.052
Total	¢ per kWh	0.328	0.328	0.328	0.328
Temporary Tax Act Credit	¢ per kWh	(0.235)	(0.235)	(0.235)	(0.235)
ZEC Recovery Charge	¢ per kWh	0.400	0.400	0.400	0.400
Basic Generation Service:					
First 600 kWh	¢ per kWh	6.793	6.821	6.793	6.821
Over 600 kWh	¢ per kWh	9.165	6.821	9.165	6.821
Reconciliation Charge	¢ per kWh	Variable	Variable	Variable	Variable
Minimum Charge: Monthly		$4.53		$6.50	
Minimum Per Contract		$27.18		$39.00	

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 6

Luminaire Charges for Service Types A and B, monthly

Nominal Lumens	Luminaire Type	Watts	Total Wattage	Present Distribution Charge	Proposed Distribution Charge
Power Bracket Luminaires					
5,800	Sodium Vapor	70	108	$5.34	$8.52
9,500	Sodium Vapor	100	142	6.42	10.24
16,000	Sodium Vapor	150	199	6.89	10.99
3,950	LED	30-44	35	N/A	7.57
5,550	LED	45-59	50	N/A	7.68
7,350	LED	60-70	65	N/A	7.75
Street Lighting Luminaires					
5,800	Sodium Vapor	70	108	$7.43	$11.86
9,500	Sodium Vapor	100	142	8.16	13.02
16,000	Sodium Vapor	150	199	10.02	15.99
27,500	Sodium Vapor	250	311	12.86	20.51
46,000	Sodium Vapor	400	488	21.22	33.85
3,000	LED	20-25	23	N/A	8.21
3,900	LED	30-39	35	N/A	8.05
5,000	LED	40-59	50	N/A	8.07
7,250	LED	60-79	68	N/A	8.41
12,000	LED	95-110	103	N/A	9.46
16,000	LED	130-150	140	N/A	9.92
22,000	LED	180-220	200	N/A	14.53
Flood lighting Luminaires					
46,000	Sodium Vapor	400	488	$21.22	$33.85
15,500	LED	115-130	125	N/A	11.43
27,000	LED	175-225	205	N/A	14.58
37,500	LED	265-315	290	N/A	15.88

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 6 (Continued)

Luminaire Charges for Service Types A and B, monthly

Nominal Lumens	Luminaire Type	Watts	Total Wattage	Present Distribution Charge	Proposed Distribution Charge
The following luminaires will no longer be installed. Charges are for existing luminaires only.					
Post Top Luminaires					
16,000	Sodium Vapor-Offset	150	199	$19.73	$31.48
Power Bracket Luminaires					
4,000	Mercury Vapor	100	127	$8.30	$13.23
7,900	Mercury Vapor	175	215	9.59	15.29
22,500	Mercury Vapor	400	462	15.28	24.37
Street Lighting Luminaires					
4,000	Mercury Vapor	100	127	$9.12	$14.54
7,900	Mercury Vapor	175	211	10.42	16.62
22,500	Mercury Vapor	400	459	16.19	25.82
1,000	Incandescent	-	92	7.41	11.82
3,400	Induction	40	45	8.00	12.76
5,950	Induction	70	75	8.17	13.03
8,500	Induction	100	110	9.20	14.68
5,890	LED	70	74	8.75	13.97
9,365	LED	100	101	10.77	17.18
Flood lighting Luminaires					
12,000	Mercury Vapor	250	296	$13.10	$20.91
40,000	Mercury Vapor	700	786	23.72	37.85
59,000	Mercury Vapor	1,000	1,105	29.55	47.14

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 6 (Continued)

Luminaire Charges for Service Types A and B, monthly

Nominal Lumens	Luminaire Type	Watts	Total Wattage	Present Distribution Charge		Proposed Distribution Charge	
15 Ft Brackets				$0.52	per month	$0.83	per month

		Present		Proposed	
Distribution and Transmission Charges for Service Type C:					
Metered					
Customer Charge (Metered)		$11.53	per month	$14.00	per month
Customer Charge (Unmetered)		2.40	per month	3.00	per month
Distribution Charge		4.992	¢ per kWh	5.936	¢ per kWh
Transmission Charge		1.224	¢ per kWh	1.224	¢ per kWh
RGGI Surcharge		0.0921	¢ per kWh	0.0921	¢ per kWh
Societal Benefit Charge		0.6050	¢ per kWh	0.6050	¢ per kWh
Securitization Charges:					
	TBC	0.276	¢ per kWh	0.276	¢ per kWh
	TBC-Tax	0.052	¢ per kWh	0.052	¢ per kWh
	Total	0.328	¢ per kWh	0.328	¢ per kWh
Temporary Tax Act Credit		(0.235)	¢ per kWh	(0.235)	¢ per kWh
ZEC Recovery Surcharge		0.400	¢ per kWh	0.400	¢ per kWh
Basic Generation Service:					
Summer		5.015	¢ per kWh	5.015	¢ per kWh
Winter		4.985	¢ per kWh	4.985	¢ per kWh
Reconciliation Charge		Variable	¢ per kWh	Variable	¢ per kWh

Minimum Charges:
Type A or B:
Sum of the monthly Distribution and Transmission Charges as specified in RATE – MONTHLY, Part (1a) times twelve.

			Present	Proposed
Type C:	Metered	per month	$11.53	$14.00
		minimum for initial term	138.36	168.00
	Unmetered	per month	2.40	3.00
		minimum for initial term	28.80	36.00

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 7
Primary

			Present Year-round	Proposed Year-round
Customer Charge:		per month	$212.35	$250.00
Distribution Charge:				
Demand Charge				
Period I	All kW @	per kW	$2.94	$5.85
Period II	All kW @	per kW	0.73	1.44
Period III	All kW @	per kW	2.70	5.36
Period IV	All kW @	per kW	0.73	1.44
Usage Charge				
Period I	All kWh @	¢ per kWh	1.770	1.770
Period II	All kWh @	¢ per kWh	1.325	1.325
Period III	All kWh @	¢ per kWh	1.770	1.770
Period IV	All kWh @	¢ per kWh	1.325	1.325
Transmission Charge (incl Trans Surch):				
Demand Charge				
Period I	All kW @	per kW	$2.55	$2.55
Period II	All kW @	per kW	0.67	0.67
Period III	All kW @	per kW	2.55	2.55
Period IV	All kW @	per kW	0.67	0.67
Usage Charge				
All kWh @		¢ per kWh	0.779	0.779
RGGI Surcharge		¢ per kWh	0.0921	0.0921
Societal Benefits Charge		¢ per kWh	0.6050	0.6050
Securitization Charges:				
TBC		¢ per kWh	0.276	0.276
TBC-Tax		¢ per kWh	0.052	0.052
Total		¢ per kWh	0.328	0.328
Temporary Tax Act Credit		¢ per kWh	(0.235)	(0.235)
ZEC Recovery Surcharge		¢ per kWh	0.400	0.400
CIEP Standby Fee		¢ per kWh	0.01599	0.01599

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 7 (Continued)
Primary

		Present Year-round	Proposed Year-round
Basic Generation Service:			
Capacity Obligation Charge			
Summer	$/kW/Month	9.7561	9.7561
Winter	$/kW/Month	9.2151	9.2151
Hourly Energy Charge**	¢ per kWh	4.600	4.600
Ancillary Services	¢ per kWh	0.000	0.000
Retail Margin	¢ per kWh	0.000	0.000
Reconciliation Charge	¢ per kWh	Variable	Variable
Space Heating:			
Distribution Charge			
Summer	¢ per kWh	4.693	6.022
Winter	¢ per kWh	2.902	3.724
Transmission Charge (incl Trans Surch):			
Year-round	¢ per kWh	0.910	0.910

Definition of Rating Periods:

Period I - 10:00 a.m. to 10:00 p.m. prevailing time, Monday through Friday except holidays, June through September.

Period II - 10:00 p.m. to 10:00 a.m. prevailing time, Monday through Friday and all hours on Saturday, Sunday and holidays, June through September.

Period III - 10:00 a.m. to 10:00 p.m. prevailing time, Monday through Friday except holidays, October through May.

Period IV - 10:00 p.m. to 10:00 a.m. prevailing time, Monday through Friday, all hours on Saturday, Sunday and holidays, October through May.

Minimum Charge: The Customer Charge

** Average based on forecast of BGS Prices for 12 ME September, 2019

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 7
High Voltage Distribution

		Present Year-round	Proposed Year-round
Customer Charge:	per month	$2,288.12	$2,288.12
Distribution Charge:			
Demand Charge			
Period I All kW @	per kW	$0.92	$1.73
Period II All kW @	per kW	0.21	0.41
Period III All kW @	per kW	0.84	1.59
Period IV All kW @	per kW	0.21	0.41
Usage Charge			
Period I All kWh @	¢ per kWh	0.203	0.203
Period II All kWh @	¢ per kWh	0.151	0.151
Period III All kWh @	¢ per kWh	0.203	0.203
Period IV All kWh @	¢ per kWh	0.151	0.151
Transmission Charge (incl Trans Surch):			
Demand Charge			
Period I All kW @	per kW	$2.55	$2.55
Period II All kW @	per kW	0.67	0.67
Period III All kW @	per kW	2.55	2.55
Period IV All kW @	per kW	0.67	0.67
Usage Charge			
All kWh @	¢ per kWh	0.779	0.779
RGGI Surcharge	¢ per kWh	0.0921	0.0921
Societal Benefits Charge	¢ per kWh	0.6050	0.6050
Securitization Charges:			
TBC	¢ per kWh	0.276	0.276
TBC-Tax	¢ per kWh	0.052	0.052
Total	¢ per kWh	0.328	0.328
Temporary Tax Act Credit	¢ per kWh	(0.235)	(0.235)
ZEC Recovery Surcharge	¢ per kWh	0.400	0.400
CIEP Standby Fee	¢ per kWh	0.01599	0.01599

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Present and Proposed Rates in Brief*

Service Classification No. 7 (Continued)
High Voltage Distribution

		Present Year-round	Proposed Year-round
Basic Generation Service:			
Capacity Obligation Charge			
Summer	$/kW/Month	9.7561	9.7561
Winter	$/kW/Month	9.2151	9.2151
Hourly Energy Charge**	¢ per kWh	4.600	4.600
Ancillary Services	¢ per kWh	0.000	0.000
Retail Margin	¢ per kWh	0.000	0.000
Reconciliation Charge	¢ per kWh	Variable	Variable

Definition of Rating Periods:

Period I - 10:00 a.m. to 10:00 p.m. prevailing time, Monday through Friday except holidays, June through September.

Period II - 10:00 p.m. to 10:00 a.m. prevailing time, Monday through Friday and all hours on Saturday, Sunday and holidays, June through September.

Period III - 10:00 a.m. to 10:00 p.m. prevailing time, Monday through Friday except holidays, October through May.

Period IV - 10:00 p.m. to 10:00 a.m. prevailing time, Monday through Friday, all hours on Saturday, Sunday and holidays, October through May.

Definition of Rating Periods:

Minimum Charge: The Customer Charge

** Average based on forecast of BGS Prices for 12 ME September, 2019

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY
Calculation of Proposed Distribution Rates
Including Sales and Use Tax @ 6.625%

	Proposed Distribution Excl SUT (a)	Proposed Distribution SUT (b = a * 6.625%) 6.625%	Proposed Distribution Incl SUT (c = a + b)
Service Classification Nos. 1 and 5			
Customer Charge ($/mo)	6.10	0.40	6.50
First 600 kWh -S ($/kWh)	0.05687	0.00377	0.06064
First 600 kWh -W ($/kWh)	0.05687	0.00377	0.06064
Over 600 kWh -S ($/kWh)	0.07163	0.00475	0.07638
Over 600 kWh -W ($/kWh)	0.05687	0.00377	0.06064
Service Classification No. 2 Secondary Non-Demand Billed Unmetered			
Customer Charge ($/mo)	13.13	0.87	14.00
Usage:			
All kWh -S ($/kWh)	0.03282	0.00217	0.03499
All kWh -W ($/kWh)	0.02974	0.00197	0.03171
Service Classification No. 2 Secondary Non-Demand Billed Metered			
Customer Charge ($/mo)	15.01	0.99	16.00
Usage:			
All kWh -S ($/kWh)	0.03282	0.00217	0.03499
All kWh -W ($/kWh)	0.02974	0.00197	0.03171
Service Classification No. 2 Secondary Demand Billed			
Customer Charge ($/mo)	19.70	1.31	21.01
Demand:			
First 5 kW -S ($/kW)	4.40	0.29	4.69
First 5 kW -W ($/kW)	3.68	0.24	3.92
Over 5 kW -S ($/kW)	6.93	0.46	7.39
Over 5 kW -W ($/kW)	5.84	0.39	6.23
Usage:			
First 4,920 kWh -S ($/kWh)	0.03068	0.00203	0.03271
First 4,920 kWh -W ($/kWh)	0.02896	0.00192	0.03088
Over 4,920 kWh -S ($/kWh)	0.02679	0.00177	0.02856
Over 4,920 kWh -W ($/kWh)	0.02621	0.00174	0.02795
Service Classification No. 2 Space Heating			
Space Heat -S ($/kWh)	0.06248	0.00414	0.06662
Space Heat -W ($/kWh)	0.03750	0.00248	0.03998

ROCKLAND ELECTRIC COMPANY
Calculation of Proposed Distribution Rates
Including Sales and Use Tax @ 6.625%

	Proposed Distribution Excl SUT (a)	Proposed Distribution SUT (b = a * 6.625%) 6.625%	Proposed Distribution Incl SUT (c = a + b)
Service Classification No. 2 Primary			
Customer Charge ($/mo)	86.28	5.72	92.00
Demand:			
All kW -S ($/kW)	4.42	0.29	4.71
All kW -W ($/kW)	3.78	0.25	4.03
Usage:			
All kWh -S ($/kWh)	0.01393	0.00092	0.01485
All kWh -W ($/kWh)	0.01393	0.00092	0.01485
Service Classification No. 3			
Customer Charge ($/mo)	8.44	0.56	9.00
Peak -S ($/kWh)	0.09498	0.00629	0.10127
Peak -W ($/kWh)	0.08520	0.00564	0.09084
Off Peak - S ($/kWh)	0.03421	0.00227	0.03648
Off Peak - W ($/kWh)	0.03421	0.00227	0.03648
Service Classification No. 7			
Customer Charge ($/mo)	234.47	15.53	250.00
Demand			
Period I ($/kW)	5.49	0.36	5.85
Period II ($/kW)	1.35	0.09	1.44
Period III ($/kW)	5.03	0.33	5.36
Period IV ($/kW)	1.35	0.09	1.44
Usage:			
Period I ($/kWh)	0.01660	0.00110	0.01770
Period II ($/kWh)	0.01243	0.00082	0.01325
Period III ($/kWh)	0.01660	0.00110	0.01770
Period IV ($/kWh)	0.01243	0.00082	0.01325
Service Classification No. 7 High Voltage Distribution			
Customer Charge ($/mo)	2,145.95	142.17	2,288.12
Demand			
Period I ($/kW)	1.62	0.11	1.73
Period II ($/kW)	0.38	0.03	0.41
Period III ($/kW)	1.49	0.10	1.59
Period IV ($/kW)	0.38	0.03	0.41
Usage			
Period I ($/kWh)	0.00190	0.00013	0.00203
Period II ($/kWh)	0.00142	0.00009	0.00151
Period III ($/kWh)	0.00190	0.00013	0.00203
Period IV ($/kWh)	0.00142	0.00009	0.00151

ROCKLAND ELECTRIC COMPANY
Calculation of Proposed Distribution Rates
Including Sales and Use Tax @ 6.625%

	Proposed Distribution Excl SUT (a)	Proposed Distribution SUT (b = a * 6.625%) 6.625%	Proposed Distribution Incl SUT (c = a + b)
Service Classification No. 7 Space Heating			
Space Heat -S ($/kWh)	0.05648	0.00374	0.06022
Space Heat -W ($/kWh)	0.03493	0.00231	0.03724
Service Classification No. 4			
5800 SV ($/luminaire/mo.)	8.34	0.55	8.89
9500 SV	9.06	0.60	9.66
16000 SV	11.02	0.73	11.75
27500 SV	14.07	0.93	15.00
46000 SV	22.82	1.51	24.33
16000 SV Offset	22.27	1.48	23.75
1000 OBI	5.52	0.37	5.89
4000 MV	7.48	0.50	7.98
7900 MV	8.81	0.58	9.39
12000 MV	11.46	0.76	12.22
22500 MV	14.55	0.96	15.51
40000 MV	22.12	1.47	23.59
59000 MV	27.96	1.85	29.81
4000 MV	11.38	0.75	12.13
7900 MV	13.94	0.92	14.86
7900 MV Offset	16.37	1.08	17.45
3400 IN	8.73	0.58	9.31
5950 IN	8.89	0.59	9.48
8500 IN	10.04	0.67	10.71
5890 LED	9.56	0.63	10.19
9365 LED	11.74	0.78	12.52
3000 LED	7.70	0.51	8.21
3900 LED	7.55	0.50	8.05
5000 LED	7.57	0.50	8.07
7250 LED	7.89	0.52	8.41
12000 LED	8.87	0.59	9.46
16000 LED	9.30	0.62	9.92
22000 LED	13.63	0.90	14.53
15500 LED	10.72	0.71	11.43
27000 LED	13.67	0.91	14.58
37500 LED	14.89	0.99	15.88
15 Foot Brackets	0.51	0.03	0.54
Undrg - Co. Owned	19.04	1.26	20.30
Undrg - Cust. Owned	4.63	0.31	4.94

ROCKLAND ELECTRIC COMPANY
Calculation of Proposed Distribution Rates
Including Sales and Use Tax @ 6.625%

	Proposed Distribution Excl SUT (a)	Proposed Distribution SUT (b = a * 6.625%) 6.625%	Proposed Distribution Incl SUT (c = a + b)
Service Classification No. 6			
5800 SV ($/luminaire/mo.)	7.99	0.53	8.52
9500 SV	9.60	0.64	10.24
16000 SV	10.31	0.68	10.99
5800 SV	11.12	0.74	11.86
9500 SV	12.21	0.81	13.02
16000 SV	15.00	0.99	15.99
27500 SV	19.24	1.27	20.51
46000 SV	31.75	2.10	33.85
46000 SV	31.75	2.10	33.85
16000 SV Offset	29.52	1.96	31.48
4000 MV	12.41	0.82	13.23
7900 MV	14.34	0.95	15.29
22500 MV	22.86	1.51	24.37
4000 MV	13.64	0.90	14.54
7900 MV	15.59	1.03	16.62
22500 MV	24.22	1.60	25.82
1000 In	11.09	0.73	11.82
12000 MV	19.61	1.30	20.91
40000 MV	35.50	2.35	37.85
59000 MV	44.21	2.93	47.14
3400 IN	11.97	0.79	12.76
5950 IN	12.22	0.81	13.03
8500 IN	13.77	0.91	14.68
5890 LED	13.10	0.87	13.97
9365 LED	16.11	1.07	17.18
3000 LED	7.70	0.51	8.21
3900 LED	7.55	0.50	8.05
5000 LED	7.57	0.50	8.07
7250 LED	7.89	0.52	8.41
12000 LED	8.87	0.59	9.46
16000 LED	9.30	0.62	9.92
22000 LED	13.63	0.90	14.53
15500 LED	10.72	0.71	11.43
27000 LED	13.67	0.91	14.58
37500 LED	14.89	0.99	15.88
3950 LED	7.10	0.47	7.57
5550 LED	7.20	0.48	7.68
7350 LED	7.27	0.48	7.75
15 Foot Brackets	0.78	0.05	0.83
Service Classification No. 6			
Customer Charge - Metered	13.13	0.87	14.00
Customer Charge - Unmetered	2.81	0.19	3.00
Energy (kWh) - Summer	0.05567	0.00369	0.05936
Energy (kWh) - Winter	0.05567	0.00369	0.05936

ROCKLAND ELECTRIC COMPANY

Monthly Billing Comparisons

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY

Monthly Billing Comparisons

SC1 Residential

	Monthly Usage (kWh)	Bill at Present Rates	Bill at Proposed Rates	Change Amount	Change Percent
Summer					
	0	$4.53	$6.50	$1.97	43.5
	50	12.23	15.04	2.81	23.0
	100	19.93	23.57	3.64	18.3
	200	35.34	40.65	5.31	15.0
	250	43.04	49.18	6.14	14.3
	300	50.74	57.72	6.98	13.8
	400	66.14	74.79	8.65	13.1
	500	81.55	91.87	10.32	12.7
	750	126.81	141.95	15.14	11.9
	1,000	176.58	196.97	20.39	11.5
	1,500	276.11	307.01	30.90	11.2
	2,000	375.65	417.05	41.40	11.0
Winter					
	0	$4.53	$6.50	$1.97	43.5
	50	13.19	15.99	2.80	21.2
	100	21.84	25.48	3.64	16.7
	200	39.15	44.46	5.31	13.6
	250	47.81	53.95	6.14	12.8
	300	56.46	63.44	6.98	12.4
	400	73.77	82.42	8.65	11.7
	500	91.09	101.41	10.32	11.3
	750	134.36	148.86	14.50	10.8
	1,000	177.64	196.31	18.67	10.5
	1,500	264.20	291.22	27.02	10.2
	2,000	350.75	386.12	35.37	10.1

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY

Monthly Billing Comparisons

SC2 General Service - Unmetered

	Monthly Usage (kWh)	Bill at Present Rates	Bill at Proposed Rates	Change Amount	Change Percent
Summer					
	0	$10.57	$14.00	$3.43	32.5
	100	23.73	27.15	3.42	14.4
	200	36.90	40.30	3.40	9.2
	300	50.06	53.46	3.40	6.8
	400	63.23	66.61	3.38	5.3
	500	76.39	79.76	3.37	4.4
	750	109.30	112.64	3.34	3.1
	1,000	142.21	145.52	3.31	2.3
	1,250	175.12	178.40	3.28	1.9
	1,500	208.03	211.28	3.25	1.6
	1,750	240.94	244.16	3.22	1.3
	2,000	273.85	277.04	3.19	1.2
Winter					
	0	$10.57	$14.00	$3.43	32.5
	50	16.52	19.95	3.43	20.8
	100	22.47	25.89	3.42	15.2
	200	34.37	37.78	3.41	9.9
	250	40.33	43.73	3.40	8.4
	300	46.28	49.67	3.39	7.3
	400	58.18	61.56	3.38	5.8
	500	70.08	73.46	3.38	4.8
	750	99.84	103.18	3.34	3.3
	1,000	129.59	132.91	3.32	2.6
	1,500	189.10	192.37	3.27	1.7
	2,000	248.61	251.82	3.21	1.3

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY

Monthly Billing Comparisons

SC2 General Service - Non-Demand Metered

	Monthly Usage (kWh)	Bill at Present Rates	Bill at Proposed Rates	Change Amount	Change Percent
Summer					
	0	$12.26	$16.00	$3.74	30.5
	100	25.42	29.15	3.73	14.7
	200	38.59	42.30	3.71	9.6
	300	51.75	55.46	3.71	7.2
	400	64.92	68.61	3.69	5.7
	500	78.08	81.76	3.68	4.7
	750	110.99	114.64	3.65	3.3
	1,000	143.90	147.52	3.62	2.5
	1,250	176.81	180.40	3.59	2.0
	1,500	209.72	213.28	3.56	1.7
	1,750	242.63	246.16	3.53	1.5
	2,000	275.54	279.04	3.50	1.3
Winter					
	0	$12.26	$16.00	$3.74	30.5
	50	18.21	21.95	3.74	20.5
	100	24.16	27.89	3.73	15.4
	200	36.06	39.78	3.72	10.3
	250	42.02	45.73	3.71	8.8
	300	47.97	51.67	3.70	7.7
	400	59.87	63.56	3.69	6.2
	500	71.77	75.46	3.69	5.1
	750	101.53	105.18	3.65	3.6
	1,000	131.28	134.91	3.63	2.8
	1,500	190.79	194.37	3.58	1.9
	2,000	250.30	253.82	3.52	1.4

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY

Monthly Billing Comparisons

SC2 General Secondary Service - Summer

Demand (kW)	Monthly Usage (kWh)	Bill at Present Rates	Bill at Proposed Rates	Change Amount	Change Percent
7	700	$140.48	$166.40	$25.92	18.5
7	1,400	220.09	244.92	24.83	11.3
7	2,100	299.71	323.44	23.73	7.9
7	2,800	379.32	401.96	22.64	6.0
10	1,000	204.00	241.03	37.03	18.2
10	2,000	317.73	353.20	35.47	11.2
10	3,000	431.46	465.37	33.91	7.9
10	4,000	545.19	577.54	32.35	5.9
25	2,500	521.60	614.19	92.59	17.8
25	5,000	800.96	889.76	88.80	11.1
25	7,500	930.19	1,018.54	88.35	9.5
25	10,000	1,059.42	1,147.32	87.90	8.3
50	5,000	1,045.96	1,231.26	185.30	17.7
50	10,000	1,304.42	1,488.82	184.40	14.1
50	15,000	1,562.87	1,746.37	183.50	11.7
50	20,000	1,821.33	2,003.93	182.60	10.0
100	10,000	1,794.42	2,171.82	377.40	21.0
100	20,000	2,311.33	2,686.93	375.60	16.3
100	30,000	2,828.24	3,202.04	373.80	13.2
100	40,000	3,345.15	3,717.15	372.00	11.1
150	15,000	2,542.87	3,112.37	569.50	22.4
150	30,000	3,318.24	3,885.04	566.80	17.1
150	45,000	4,093.60	4,657.70	564.10	13.8
150	60,000	4,868.97	5,430.37	561.40	11.5

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY

Monthly Billing Comparisons

SC2 General Secondary Service - Winter

Demand (kW)	Monthly Usage (kWh)	Bill at Present Rates	Bill at Proposed Rates	Change Amount	Change Percent
7	700	$128.48	$150.98	$22.50	17.5
7	1,400	203.50	225.13	21.63	10.6
7	2,100	278.52	299.29	20.77	7.5
7	2,800	353.54	373.44	19.90	5.6
10	1,000	185.29	217.14	31.85	17.2
10	2,000	292.46	323.07	30.61	10.5
10	3,000	399.63	429.00	29.37	7.3
10	4,000	506.80	534.93	28.13	5.6
25	2,500	469.35	547.94	78.59	16.7
25	5,000	732.79	808.36	75.57	10.3
25	7,500	860.70	935.62	74.92	8.7
25	10,000	988.60	1,062.87	74.27	7.5
50	5,000	938.29	1,094.86	156.57	16.7
50	10,000	1,194.10	1,349.37	155.27	13.0
50	15,000	1,449.90	1,603.87	153.97	10.6
50	20,000	1,705.71	1,858.38	152.67	9.0
100	10,000	1,605.10	1,922.37	317.27	19.8
100	20,000	2,116.71	2,431.38	314.67	14.9
100	30,000	2,628.32	2,940.39	312.07	11.9
100	40,000	3,139.93	3,449.40	309.47	9.9
150	15,000	2,271.90	2,749.87	477.97	21.0
150	30,000	3,039.32	3,513.39	474.07	15.6
150	45,000	3,806.73	4,276.90	470.17	12.4
150	60,000	4,574.15	5,040.42	466.27	10.2

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY

Monthly Billing Comparisons

SC2 General Primary Service - Summer

Demand (kW)	Monthly Usage (kWh)	Bill at Present Rates	Bill at Proposed Rates	Change Amount	Change Percent
100	20,000	$3,273.27	$3,060.97	($212.30)	(6.5)
100	30,000	4,216.38	4,004.08	(212.30)	(5.0)
100	40,000	5,159.49	4,947.19	(212.30)	(4.1)
100	50,000	6,102.60	5,890.30	(212.30)	(3.5)
150	30,000	4,874.88	4,553.08	(321.80)	(6.6)
150	45,000	6,289.55	5,967.75	(321.80)	(5.1)
150	60,000	7,704.21	7,382.41	(321.80)	(4.2)
150	75,000	9,118.88	8,797.08	(321.80)	(3.5)
200	40,000	6,476.49	6,045.19	(431.30)	(6.7)
200	60,000	8,362.71	7,931.41	(431.30)	(5.2)
200	80,000	10,248.93	9,817.63	(431.30)	(4.2)
200	100,000	12,135.15	11,703.85	(431.30)	(3.6)
500	100,000	16,086.15	14,997.85	(1,088.30)	(6.8)
500	150,000	20,801.70	19,713.40	(1,088.30)	(5.2)
500	200,000	25,517.25	24,428.95	(1,088.30)	(4.3)
500	250,000	30,232.80	29,144.50	(1,088.30)	(3.6)
750	150,000	24,094.20	22,458.40	(1,635.80)	(6.8)
750	225,000	31,167.53	29,531.73	(1,635.80)	(5.2)
750	300,000	38,240.85	36,605.05	(1,635.80)	(4.3)
750	375,000	45,314.18	43,678.38	(1,635.80)	(3.6)
1000	200,000	32,102.25	29,918.95	(2,183.30)	(6.8)
1000	300,000	41,533.35	39,350.05	(2,183.30)	(5.3)
1000	400,000	50,964.45	48,781.15	(2,183.30)	(4.3)
1000	500,000	60,395.55	58,212.25	(2,183.30)	(3.6)

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY

Monthly Billing Comparisons

SC2 General Primary Service - Winter

Demand (kW)	Monthly Usage (kWh)	Bill at Present Rates	Bill at Proposed Rates	Change Amount	Change Percent
100	20,000	$2,984.92	$2,803.62	($181.30)	(6.1)
100	30,000	3,883.93	3,702.63	(181.30)	(4.7)
100	40,000	4,782.94	4,601.64	(181.30)	(3.8)
100	50,000	5,681.95	5,500.65	(181.30)	(3.2)
150	30,000	4,440.93	4,165.63	(275.30)	(6.2)
150	45,000	5,789.45	5,514.15	(275.30)	(4.8)
150	60,000	7,137.96	6,862.66	(275.30)	(3.9)
150	75,000	8,486.48	8,211.18	(275.30)	(3.2)
200	40,000	5,896.94	5,527.64	(369.30)	(6.3)
200	60,000	7,694.96	7,325.66	(369.30)	(4.8)
200	80,000	9,492.98	9,123.68	(369.30)	(3.9)
200	100,000	11,291.00	10,921.70	(369.30)	(3.3)
500	100,000	14,633.00	13,699.70	(933.30)	(6.4)
500	150,000	19,128.05	18,194.75	(933.30)	(4.9)
500	200,000	23,623.10	22,689.80	(933.30)	(4.0)
500	250,000	28,118.15	27,184.85	(933.30)	(3.3)
750	150,000	21,913.05	20,509.75	(1,403.30)	(6.4)
750	225,000	28,655.63	27,252.33	(1,403.30)	(4.9)
750	300,000	35,398.20	33,994.90	(1,403.30)	(4.0)
750	375,000	42,140.78	40,737.48	(1,403.30)	(3.3)
1000	200,000	29,193.10	27,319.80	(1,873.30)	(6.4)
1000	300,000	38,183.20	36,309.90	(1,873.30)	(4.9)
1000	400,000	47,173.30	45,300.00	(1,873.30)	(4.0)
1000	500,000	56,163.40	54,290.10	(1,873.30)	(3.3)

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY

Monthly Billing Comparisons

SC5 Residential with Space Heating

	Monthly Usage (kWh)	Bill at Present Rates	Bill at Proposed Rates	Change Amount	Change Percent
Summer					
	0	$4.53	$6.50	$1.97	43.5
	50	11.84	14.61	2.77	23.4
	100	19.15	22.72	3.57	18.6
	200	33.77	38.94	5.17	15.3
	250	41.08	47.06	5.98	14.6
	300	50.05	57.14	7.09	14.2
	400	68.00	77.31	9.31	13.7
	500	85.95	97.48	11.53	13.4
	750	123.53	139.49	15.96	12.9
	1,000	131.95	147.91	15.96	12.1
	1,500	148.77	164.73	15.96	10.7
	2,000	165.60	181.56	15.96	9.6
Winter					
	0	$4.53	$6.50	$1.97	43.5
	50	11.85	14.63	2.78	23.5
	100	19.18	22.75	3.57	18.6
	200	33.82	39.00	5.18	15.3
	250	41.15	47.13	5.98	14.5
	300	48.47	55.25	6.78	14.0
	400	63.11	71.50	8.39	13.3
	500	77.76	87.75	9.99	12.8
	750	108.74	121.93	13.19	12.1
	1,000	117.15	130.35	13.20	11.3
	1,500	133.97	147.17	13.20	9.9
	2,000	150.80	164.00	13.20	8.8

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY

Monthly Billing Comparisons
Service Classification No. 7

Annual Bill

Demand (kW)	Monthly Usage (kWh)	Percent Energy Split Peak	Off-Peak	Bill at Present Rates	Bill at Proposed Rates	Change Amount	Percent
1,000	300,000	35%	65%	$484,744	$530,111	45,367	9.4
1,000	300,000	50%	50%	487,147	532,514	45,367	9.3
1,000	400,000	35%	65%	581,534	626,902	45,368	7.8
1,000	400,000	50%	50%	584,738	630,106	45,368	7.8
2,000	600,000	35%	65%	966,939	1,057,223	90,284	9.3
2,000	600,000	50%	50%	971,745	1,062,029	90,284	9.3
2,000	800,000	35%	65%	1,160,519	1,250,803	90,284	7.8
2,000	800,000	50%	50%	1,166,927	1,257,211	90,284	7.7
3,000	900,000	35%	65%	1,449,135	1,584,334	135,199	9.3
3,000	900,000	50%	50%	1,456,344	1,591,543	135,199	9.3
3,000	1,200,000	35%	65%	1,739,505	1,874,705	135,200	7.8
3,000	1,200,000	50%	50%	1,749,117	1,884,317	135,200	7.7
4,000	1,200,000	35%	65%	1,931,330	2,111,446	180,116	9.3
4,000	1,200,000	50%	50%	1,940,942	2,121,058	180,116	9.3
4,000	1,600,000	35%	65%	2,318,490	2,498,606	180,116	7.8
4,000	1,600,000	50%	50%	2,331,306	2,511,422	180,116	7.7
5,000	1,500,000	35%	65%	2,413,525	2,638,557	225,032	9.3
5,000	1,500,000	50%	50%	2,425,540	2,650,572	225,032	9.3
5,000	2,000,000	35%	65%	2,897,476	3,122,508	225,032	7.8
5,000	2,000,000	50%	50%	2,913,496	3,138,528	225,032	7.7

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY

Monthly Billing Comparisons
Service Classification No. 7

Summer Bill

Demand (kW)	Monthly Usage (kWh)	Percent Energy Split Peak	Off-Peak	Bill at Present Rates	Bill at Proposed Rates	Change Amount	Percent
1,000	300,000	35%	65%	$40,915.97	$44,502.62	$3,586.65	8.8
1,000	300,000	50%	50%	41,116.22	44,702.87	3,586.65	8.7
1,000	400,000	35%	65%	48,981.81	52,568.46	3,586.65	7.3
1,000	400,000	50%	50%	49,248.81	52,835.46	3,586.65	7.3
2,000	600,000	35%	65%	81,619.59	88,755.24	7,135.65	8.7
2,000	600,000	50%	50%	82,020.09	89,155.74	7,135.65	8.7
2,000	800,000	35%	65%	97,751.27	104,886.92	7,135.65	7.3
2,000	800,000	50%	50%	98,285.27	105,420.92	7,135.65	7.3
3,000	900,000	35%	65%	122,323.21	133,007.86	10,684.65	8.7
3,000	900,000	50%	50%	122,923.96	133,608.61	10,684.65	8.7
3,000	1,200,000	35%	65%	146,520.73	157,205.38	10,684.65	7.3
3,000	1,200,000	50%	50%	147,321.73	158,006.38	10,684.65	7.3
4,000	1,200,000	35%	65%	163,026.83	177,260.48	14,233.65	8.7
4,000	1,200,000	50%	50%	163,827.83	178,061.48	14,233.65	8.7
4,000	1,600,000	35%	65%	195,290.19	209,523.84	14,233.65	7.3
4,000	1,600,000	50%	50%	196,358.19	210,591.84	14,233.65	7.2
5,000	1,500,000	35%	65%	203,730.45	221,513.10	17,782.65	8.7
5,000	1,500,000	50%	50%	204,731.70	222,514.35	17,782.65	8.7
5,000	2,000,000	35%	65%	244,059.65	261,842.30	17,782.65	7.3
5,000	2,000,000	50%	50%	245,394.65	263,177.30	17,782.65	7.2

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY

Monthly Billing Comparisons
Service Classification No. 7

Winter Bill

Demand (kW)	Monthly Usage (kWh)	Percent Energy Split Peak	Off-Peak	Bill at Present Rates	Bill at Proposed Rates	Change Amount	Percent
1,000	300,000	35%	65%	$40,134.97	$44,012.62	$3,877.65	9.7
1,000	300,000	50%	50%	40,335.22	44,212.87	3,877.65	9.6
1,000	400,000	35%	65%	48,200.81	52,078.46	3,877.65	8.0
1,000	400,000	50%	50%	48,467.81	52,345.46	3,877.65	8.0
2,000	600,000	35%	65%	80,057.59	87,775.24	7,717.65	9.6
2,000	600,000	50%	50%	80,458.09	88,175.74	7,717.65	9.6
2,000	800,000	35%	65%	96,189.27	103,906.92	7,717.65	8.0
2,000	800,000	50%	50%	96,723.27	104,440.92	7,717.65	8.0
3,000	900,000	35%	65%	119,980.21	131,537.86	11,557.65	9.6
3,000	900,000	50%	50%	120,580.96	132,138.61	11,557.65	9.6
3,000	1,200,000	35%	65%	144,177.73	155,735.38	11,557.65	8.0
3,000	1,200,000	50%	50%	144,978.73	156,536.38	11,557.65	8.0
4,000	1,200,000	35%	65%	159,902.83	175,300.48	15,397.65	9.6
4,000	1,200,000	50%	50%	160,703.83	176,101.48	15,397.65	9.6
4,000	1,600,000	35%	65%	192,166.19	207,563.84	15,397.65	8.0
4,000	1,600,000	50%	50%	193,234.19	208,631.84	15,397.65	8.0
5,000	1,500,000	35%	65%	199,825.45	219,063.10	19,237.65	9.6
5,000	1,500,000	50%	50%	200,826.70	220,064.35	19,237.65	9.6
5,000	2,000,000	35%	65%	240,154.65	259,392.30	19,237.65	8.0
5,000	2,000,000	50%	50%	241,489.65	260,727.30	19,237.65	8.0

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY

Monthly Billing Comparisons

Service Classification No. 7 - High Voltage Distribution

Annual Bill

Demand (kW)	Monthly Usage (kWh)	Percent Energy Split Peak	Off-Peak	Bill at Present Rates	Bill at Proposed Rates	Change Amount	Percent
1,000	300,000	35%	65%	$433,861	$449,589	15,728	3.6
1,000	300,000	50%	50%	434,142	449,870	15,728	3.6
1,000	400,000	35%	65%	514,913	530,641	15,728	3.1
1,000	400,000	50%	50%	515,287	531,015	15,728	3.1
2,000	600,000	35%	65%	840,265	871,721	31,456	3.7
2,000	600,000	50%	50%	840,826	872,282	31,456	3.7
2,000	800,000	35%	65%	1,002,368	1,033,824	31,456	3.1
2,000	800,000	50%	50%	1,003,116	1,034,572	31,456	3.1
3,000	900,000	35%	65%	1,246,668	1,293,852	47,184	3.8
3,000	900,000	50%	50%	1,247,511	1,294,695	47,184	3.8
3,000	1,200,000	35%	65%	1,489,823	1,537,007	47,184	3.2
3,000	1,200,000	50%	50%	1,490,946	1,538,130	47,184	3.2
4,000	1,200,000	35%	65%	1,653,072	1,715,984	62,912	3.8
4,000	1,200,000	50%	50%	1,654,195	1,717,107	62,912	3.8
4,000	1,600,000	35%	65%	1,977,278	2,040,190	62,912	3.2
4,000	1,600,000	50%	50%	1,978,776	2,041,688	62,912	3.2
5,000	1,500,000	35%	65%	2,059,476	2,138,116	78,640	3.8
5,000	1,500,000	50%	50%	2,060,880	2,139,520	78,640	3.8
5,000	2,000,000	35%	65%	2,464,733	2,543,373	78,640	3.2
5,000	2,000,000	50%	50%	2,466,605	2,545,245	78,640	3.2

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY

Monthly Billing Comparisons
Service Classification No. 7 - High Voltage Distribution

Summer Bill

Demand (kW)	Monthly Usage (kWh)	Percent Energy Split Peak	Off-Peak	Bill at Present Rates	Bill at Proposed Rates	Change Amount	Percent
1,000	300,000	35%	65%	$36,569.09	$37,559.09	$990.00	2.7
1,000	300,000	50%	50%	36,592.49	37,582.49	990.00	2.7
1,000	400,000	35%	65%	43,323.38	44,313.38	990.00	2.3
1,000	400,000	50%	50%	43,354.58	44,344.58	990.00	2.3
2,000	600,000	35%	65%	70,850.06	72,830.06	1,980.00	2.8
2,000	600,000	50%	50%	70,896.86	72,876.86	1,980.00	2.8
2,000	800,000	35%	65%	84,358.64	86,338.64	1,980.00	2.3
2,000	800,000	50%	50%	84,421.04	86,401.04	1,980.00	2.3
3,000	900,000	35%	65%	105,131.03	108,101.03	2,970.00	2.8
3,000	900,000	50%	50%	105,201.23	108,171.23	2,970.00	2.8
3,000	1,200,000	35%	65%	125,393.90	128,363.90	2,970.00	2.4
3,000	1,200,000	50%	50%	125,487.50	128,457.50	2,970.00	2.4
4,000	1,200,000	35%	65%	139,412.00	143,372.00	3,960.00	2.8
4,000	1,200,000	50%	50%	139,505.60	143,465.60	3,960.00	2.8
4,000	1,600,000	35%	65%	166,429.16	170,389.16	3,960.00	2.4
4,000	1,600,000	50%	50%	166,553.96	170,513.96	3,960.00	2.4
5,000	1,500,000	35%	65%	173,692.97	178,642.97	4,950.00	2.8
5,000	1,500,000	50%	50%	173,809.97	178,759.97	4,950.00	2.8
5,000	2,000,000	35%	65%	207,464.42	212,414.42	4,950.00	2.4
5,000	2,000,000	50%	50%	207,620.42	212,570.42	4,950.00	2.4

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY

Monthly Billing Comparisons
Service Classification No. 7 - High Voltage Distribution

Winter Bill

Demand (kW)	Monthly Usage (kWh)	Percent Energy Split Peak	Off-Peak	Bill at Present Rates	Bill at Proposed Rates	Change Amount	Percent
1,000	300,000	35%	65%	$35,948.09	$37,419.09	$1,471.00	4.1
1,000	300,000	50%	50%	35,971.49	37,442.49	1,471.00	4.1
1,000	400,000	35%	65%	42,702.38	44,173.38	1,471.00	3.4
1,000	400,000	50%	50%	42,733.58	44,204.58	1,471.00	3.4
2,000	600,000	35%	65%	69,608.06	72,550.06	2,942.00	4.2
2,000	600,000	50%	50%	69,654.86	72,596.86	2,942.00	4.2
2,000	800,000	35%	65%	83,116.64	86,058.64	2,942.00	3.5
2,000	800,000	50%	50%	83,179.04	86,121.04	2,942.00	3.5
3,000	900,000	35%	65%	103,268.03	107,681.03	4,413.00	4.3
3,000	900,000	50%	50%	103,338.23	107,751.23	4,413.00	4.3
3,000	1,200,000	35%	65%	123,530.90	127,943.90	4,413.00	3.6
3,000	1,200,000	50%	50%	123,624.50	128,037.50	4,413.00	3.6
4,000	1,200,000	35%	65%	136,928.00	142,812.00	5,884.00	4.3
4,000	1,200,000	50%	50%	137,021.60	142,905.60	5,884.00	4.3
4,000	1,600,000	35%	65%	163,945.16	169,829.16	5,884.00	3.6
4,000	1,600,000	50%	50%	164,069.96	169,953.96	5,884.00	3.6
5,000	1,500,000	35%	65%	170,587.97	177,942.97	7,355.00	4.3
5,000	1,500,000	50%	50%	170,704.97	178,059.97	7,355.00	4.3
5,000	2,000,000	35%	65%	204,359.42	211,714.42	7,355.00	3.6
5,000	2,000,000	50%	50%	204,515.42	211,870.42	7,355.00	3.6

*All Rates Include Sales and Use Tax

ROCKLAND ELECTRIC COMPANY

Summary of Total Revenue Impacts

Service Classification	Total Sales (MWh)	Total Current Revenue ($000s)	Total Proposed Revenue ($000s)	Change ($000s)	Percent Change
SC1 Res Svc & SC5 Res S	699,591	$112,895.7	$125,992.9	$13,097.3	11.6%
SC2 Sec Non Dmd Billed	6,327	980.9	1,042.3	61.4	6.3%
SC2 Sec Dmd Billed	478,653	59,828.9	64,905.2	5,076.3	8.5%
SC2 Space Heating	21,151	2,468.1	2,774.5	306.4	12.4%
SC2 Pri	70,292	7,274.6	6,976.0	(298.7)	-4.1%
SC3 Res TOD Heating	242	32.5	39.0	6.5	20.1%
SC4 Public Street Lighting	5,727	1,139.3	1,289.7	150.5	13.2%
SC6 POL - Dusk to Dawn	3,461	618.7	860.9	242.2	39.1%
SC6 POL - Energy Only	2,085	243.0	265.5	22.4	9.2%
SC7 Pri	168,027	17,805.6	18,918.4	1,112.7	6.2%
SC7 High Voltage	53,934	3,716.6	3,791.9	75.3	2.0%
SC7 Space Heating	5,731	587.5	642.6	55.2	9.4%
	1,515,224	$207,591.4	$227,498.9	$19,907.4	9.6%

Proposed Revenue Requirement	$19,906.0
Over/(Under)	$1.4

Note:
An estimated electric supply charge for retail access customers has been included in total revenues.

ROCKLAND ELECTRIC COMPANY, INC

Rockland Electric Company, Inc.
Advanced Metering Infrastructure Metrics

March 31, 2019

Rockland Electric Company

Table of Contents

1. AMI Project Plan Update

Rockland Electric Company AMI Project Metrics:

Rockland Electric Company's ("RECO" or the "Company") Advanced Metering Infrastructure ("AMI") Program proposal was approved by the New Jersey Board of Public Utilities' ("BPU") *Decision and Order for Approval of an Advanced Metering Program*, dated August 23, 2017*,* in BPU Docket No. ER16060524 ("AMI Order"). The AMI Order required the Company to establish AMI Project Metrics and to provide the BPU with a series of updates on these AMI Project Metrics. The Company filed its final AMI Project Metrics with the BPU in December 2017. This document, including the attached AMI Metrics Tracker (collectively the "March 2019 Report"), provides an update with detail regarding each specified metric.

Project Overview:

RECO spent much of the first four months of 2018 finalizing the planning for field deployment of AMI communications equipment (pole mounted Access Points and Relays) and AMI electric meters. The Company began deploying communication devices in April 2018 and completed the installation of 142 devices by August 2018.

RECO began AMI electric meter deployment in May 2018 in the Mahwah area of Bergen County. The Company is scheduled to complete mass deployment for its New Jersey service territory (*i.e*., 73,000 eligible meters) by the end of the second quarter 2019. The RECO AMI team monitored installation safety, quality, customer interaction, customer engagement and the opt-out process. The Company managed the meter deployment from a warehouse leased by the Company's meter installation vendor ("MIV"), Aclara. The MIV warehouse was in Allendale, New Jersey, in close proximity to the Route 17 corridor.

The backbone of any AMI project is the technology. RECO's parent Company Orange and Rockland Utilities, Inc. ("O&R"), in collaboration with Consolidated Edison Company of New York, Inc., deployed the AMI Head End System, Meter Asset Management System (associated data conversion and inventory KIOSKS), Meter Data Management System, Profield Meter installation system (for mobile workforce management) and customer system changes in 2017. These system changes continue to be closely monitored and are working well in support of AMI billing and customer engagement efforts.

The customer continues to be a major focus for the Company on this project. To date, the Company has employed focus groups, surveys, customer education events, home shows and municipality events to convey information regarding the AMI Program, engage customers and answer questions. Through these events, the Company is seeing a clear shift toward deeper customer engagement. The focus groups, surveys and home show interactions have demonstrated that there is a greater understanding of AMI by a broader section of the customer base. Home show attendees were more confident in their knowledge of AMI and were generally asking more about when their meters would be installed. The more recent community events with customers and elected officials have indicated a much higher rate of interest in the effort as compared to prior years.

The AMI Program is being managed through software updates and system enhancements (Releases) to increase AMI functionality. The first release occurred in May 2016 under the New York Smart Meter program and consisted of standing up the AMI Head End System, MDMS and MAMS. The second release of AMI functionality occurred on May 7, 2018. This release included automated meter hot socket alarms and utility employee initiated meter interactions such as Power Status Verification, On Demand Reads and Remote Connect/Disconnect. The Company deployed the third release of AMI functionality on September 30, 2018. This third release included automated remote meter connect/disconnect and AMI data integration into the Outage Management System. A release labeled 3.5, which will integrate power off and power on messages from AMI meters directly into the Outage Management System, will be ready by June 2019.

The automated connect/disconnect functionality is being used to support residential and small commercial meters that have remote switch capability. The Company can now provide more timely service to those customers who are moving in or moving out of premises. In addition, the functionality is being used to support collections work in the field. Customer meter technicians continue to make contact in person with customers who are eligible to have their service terminated for non-payment. However, if payment arrangements cannot be made, the technician can now leave the premise instead of disconnecting the service at the meter. Once the technician completes the paperwork in the automated system, a signal is sent over the air to open the switch in the meter thereby disconnecting service. Similarly, when payment is made by a customer who was disconnected for non-payment, an over the air signal is sent to the meter to close the switch in the meter thereby re-connecting service.

On September 30, 2018, the Company completed the first round of AMI meter data integration into the Company's Outage Management System. This integration allows any AMI meter that is associated with an outage to be "pinged" by the Company prior to dispatching crews to the field. The ability to "ping" a meter provides confirmation that power is on or off at the premise. This information allows the Company to manage field crews more efficiently during restoration.

On March 31, 2019, the Company launched the latest functionality associated with AMI. Specifically, the Company implemented the next layer of AMI meter integration into the Outage Management System. This has allowed the Company to run a parallel environment comparing AMI Meter power off/on messages that are flowing into a test outage management system environment to the production Outage Management System environment to confirm accuracy. After approximately three months of this parallel testing, the functionality will be moved into the production Outage Management System.

In sum, the RECO AMI Program project is on schedule and on budget. The Company continues to support and engage both internal and external stakeholders as part of this project. The Company is committed to providing the information and tools necessary for customers to become informed and engaged energy consumers. The Company's customer engagement plan is designed to be adaptive in order to meet customers' changing needs.

2. Customer Engagement

2.1. DCX Portal

2.1.1. Customers using the AMI Portal – As of March 31, 2019, 13,285 RECO customers have logged into the online customer portal to see their detailed AMI usage information. This represents 20% of the customer base with AMI meters.

2.1.2. Customers identified to receive energy saving messaging – Customers with commissioned meters will be receiving a welcome letter six weeks post commissioning. As of March 31, 2019, the Company has sent out 51,673 welcome letters.

2.2. Awareness / Education

2.2.1. Near Real Time Data – As of March 31, 2019 RECO has given 65,642 customers access to near real time data which is available through the My Account portal on oru.com.

2.2.2. Customer Knowledge of AMI – In the Customer Engagement Plan, RECO committed to conduct an awareness survey to establish a baseline. The baseline survey was conducted in February 2018 which was just as smart meters were beginning to be deployed. The Company will conduct a post-deployment awareness survey in May 2019.

Previous Statistics:
February 2018- 42% Awareness: 595 Online; 200 Telephone Surveys
September 2018- 68% Awareness: 309 Online; 200 Telephone Surveys

2.2.3. Targeted Energy Forum Presentations

Over the past year, the Company participated in a multitude of outreach events and community forums where the Company discussed and answered questions regarding the RECO AMI Meter Program. The list below details the date and audience of the events:

4/04/18	AMI Meter Presentation with Wyckoff Police Department
4/17/18	AMI Meter Presentation with Cresskill Police Department
4/21/18	AMI Meter Booth at Northern Valley Earth Day Fair – Demarest
4/25/18	AMI Meter Presentation with Village of Norwood
5/09/18	RECO AMI Meter Municipal Information Exchange
6/09/18	AMI Meter Presentation Oakland NJ Senior Community Center
6/20/18	BPU Status Update, Trenton NJ.
7/03/18	Meeting with the Mayor of the Borough of Franklin Lakes
8/27/18	Meeting with the Mayor of Upper Saddle River
9/06/18	Upper Saddle River Borough and Council Meeting
9/22/18	AMI Meter Table at Norwood Day
12/11/18	AMI Meter Presentation at the Ramsey Democratic Club
01/15/19	Northvale Senior Citizen's Club
03/17/19	Norwood Senior Citizen's Club
02/22/19	Rockland County Home Show
02/23/19	Rockland County Home Show
02/24/19	Rockland County Home Show

2.3. Green Button Connect My Data – RECO currently has one third-party vendor fully onboarded to use Green Button Connect and eleven other vendors going through the cybersecurity vetting process. As of March 31, 2019, one customer has enrolled in Green Button Connect.

3. Billing

3.1. Estimated Bills – The estimated bill percentage for the Company as of March 31, 2019 is .86% of customer accounts.

4. Outage Management

4.1. Emergency response labor reduction – The Company was able to save approximately $36,000 systemwide by not having to respond to 71 false outages for the quarter ended March 2019.

4.2. Proactive power quality issue identification – The Company was able to identify and resolve five power quality issues system-wide through the use of AMI.

4.3. Number of false outages resolved through AMI – The Company was able to identify 71 false outages system-wide through the use of AMI for the quarter ending March 2019.

5. System Operations and Environmental Benefits

5.1. Reduction in manual meter operations costs – The Company has seen a reduction of $100,000 within its Meter Reading Department in a comparison of costs from the first quarter 2018 and 2019.

5.2. Reduction in vehicle fuel consumption and vehicle emissions – As of this March 2019 Report, five meter reader vehicles have been removed from the fleet and our estimated fuel savings based for the first quarter is $4,400. The Company has not estimated the emissions savings at this time.

5.3. Quantify kWh savings attributed to Voltage Var Optimization ("VVO") - As indicated in the AMI Business Case, RECO plans to phase in VVO starting in 2020. In April 2021, RECO will report kWh savings attributed to VVO for 2020.

5.4. Environmental benefits due to VVO – As indicated in the AMI Business Case, RECO plans to phase in VVO commencing in 2020. In April 2021, RECO will report environmental benefits due to VVO for 2020.

6. Meter Deployment

6.1. The number of AMI meters deployed per month (Planned Installs vs. Actual Installs) is set forth below.

	Planned Installed	Actual Installs
Jan-18		27
Feb-18		88
Mar-18		84
Apr-18		134
May-18	3,320	2,931
Jun-18	4,610	4,226
Jul-18	8,680	4,040
Aug-18	8,725	6,430
Sep-18	8,269	4,072
Oct-18	10,819	9,470
Nov-18	6,123	8,943
Dec-18	7,545	8,697
2018	**58,091**	**49,142**
Jan-19	5,520	7,567
Feb-19	4,744	7,131
Mar-19	4,066	6,750
2019 ytd	**14,330**	**21,448**
TOTAL	**72,421**	**70,590**

6.2. Customers Opting-Out of AMI meter deployment

As of March 31, 2019, 644 customers have opted-out of AMI meter deployment.

7. Major Event

7.1. AMI Network Performance – RECO has not experienced a major storm in the last three months.

7.2. Estimated Reduction in Major Event Duration – date to be presented: April 30, 2020.

7.3. Nested Outage Detection – RECO has not experienced a major storm in the last three months.

8. Project Management Report

8.1. Safety – as of this March 2019 Report, RECO has had one recordable minor injury on the AMI Program Project. An installer slipped on ice, while wearing ice cleats, in March while leaving an installation location. The installer injured his shoulder. The Company always aims to accomplish zero harm but considering the significant amount of field work that has been performed in such a short period time the safety record overall is very good.

8.2. Retirement Testing – Meters continue to be shipped to our testing vendor. The retirement test results for AMI meter exchanges are to be provided to the BPU as part of the standard quarterly test report that is provided by RECO's Customer Meter Operations. The retirement testing and test results are progressing as expected.

8.3. Communication Deployment – As of December 31, 2018 RECO has installed 142 communication devices which represents the completion of the Communication Deployment.

Rockland Electric Company AMI Metrics								
Category	**Service/Function**	**Ref #**	**Metric**	**Description**	**Goal**	**Report Start Date (At end of quarter specified)**	**Update Frequency**	**Notes**
Customer Engagement	DCX Portal	2.1.1	**Customers using the AMI Portal**	% of customers with AMI meters who log into portal to view usage information each quarter.	NA Report Volume of Customers	End of 1st Quarter after meter deployment commences	Quarterly	Track how many customers have logged into the portal to view their energy usage.
		2.1.2	**Customers identified to receive energy saving messaging - All (Including Low Income)**	% of customers identified to receive messages regarding their energy savings tools, personalized usage and or savings tips	NA Report Volume of Customers	End of 1st Quarter after meter deployment commences	Quarterly	The Company is determining the feasibility of tracking the number of customers who use the online portal once they receive their specific message for energy savings to identify energy usage since the analytics dashboards will not be available until 2018
	Awareness/Education	2.2.1	**Near Real Time Data**	Number of customers who have access to near real time data via the web after AMI meter installation	NA	Q3 2018	Quarterly	Starting at end of 4Q2018, 99% of meters deployed will be presented with near real time data.
		2.2.2	**Customer Knowledge of AMI**	Awareness survey related to AMI benefits and features.	Survey to be conducted prior to AMI deployment to establish a baseline goal. Subsequent surveys to determine knowledge improvement on periodic basis after goal is established.	Q1 2018	Quarterly	The Company will perform an initial survey that will be used to determine the initial customer awareness . The survey will be a random sample that is representative of the Company's service territory.
		2.2.3	**Targeted Energy Forum Presentations**	Number of presentations provided; Target 2 per year	2 per year	Q1 2018	Quarterly	Schedule and present two energy forums within the service territory per year. These may be combined with similar energy forums in Bergen, Passaic and Sussex Counties New Jersey
	Green Button Connect My Data	2.3	**Green Button Connect My Data**	Track number of customers who use GBC to share their energy usage information with third parties	NA Volume of customers using GBC will be reported	End of 1st Quarter after meter deployment commences	Quarterly	Track the number of customer who use GBC per quarter
Billing	Billing	3.1	**Estimated Bills - AMI accounts**	% of accounts with bills which are estimated	Less than 1.5 % of bills rendered every 6 months for customers with an AMI meter will be estimated.	End of 1st Quarter after meter deployment commences	Quarterly	Track the number of AMI bills that are generated with an estimated reading

Rockland Electric Company AMI Metrics								
Category	**Service/Function**	**Ref #**	**Metric**	**Description**	**Goal**	**Report Start Date (At end of quarter specified)**	**Update Frequency**	**Notes**
Outage Management	O&M Cost Reduction	4.1	**Emergency response labor reduction**	Number of single outages for a large storm 50,000 or more outages) that were determined remotely via AMI eliminating the need to send a crew or call to confirm power restoration.	NA - Report Quarterly Value	End of 3rd Quarter 2018 see Note	Quarterly	The Company will be reporting this metric when the new Outage Management System is fully integrated with AMI at the end of 2018.
	Power Quality	4.2	**Proactive power quality issue identification**	Number of power quality issues identified through the use of AMI data.	NA - Report Quarterly Value	End of 3rd Quarter 2018 see Note	Quarterly	The Company will report annually on the volume of PQ issues identified via AMI data.
	False Outages	4.3	**Number of false outages resolved through AMI**	Number of false outages that were found through AMI that Company did not have to send a crew or call to confirm.	NA - Report Quarterly Value	End of 3rd Quarter 2018 see Note	Quarterly	The Company will be reporting this metric when the new Outage Management System is fully integrated with AMI at the end of 2018.
System Operation and Environmental Benefits	Meter Reading Costs	5.1	**Reduction in manual meter operations costs**	Track avoided meter operations O&M costs and report	In accordance with O&M savings filed in AMI Business Plan.	Q1 2019 - O&M budgets will be reduced starting in 2019	Quarterly	
	Environmental benefits resulting from less vehicle usage	5.2	**Reduction in vehicle fuel consumption and vehicle emissions**	Reduction in vehicle emissions due to reduction in manual meter reading.	This goal will be aligned with the information provided in the AMI Business Plan on tons of carbon avoided.	End of 1st Quarter after meter deployment commences	Quarterly	
	Var Voltage Optimization (VVO)- KWh savings	5.3	**Quantify kWh savings attributed to VVO**	Quantify kWh savings attributed to VVO	In accordance with savings identified in AMI Business Plan.	End of 1st Quarter 2020	Quarterly	
	Var Voltage Optimization (VVO)- Environmental benefits	5.4	**Environmental benefits due to VVO**	Provide total fuel consumption savings and corresponding emissions reductions	This goal will be aligned with the information provided in the AMI Business Plan on tons of carbon avoided.	End of 1st Quarter 2020	Quarterly	
Meter Deployment	Deployment	6.1	**AMI Meters Deployed per quarter**	Number of Meters Deployed per quarter	TBD - the final meter deployment schedule is yet to be developed	End of 1st Quarter after meter deployment commences	Quarterly	The Company will report this metric four times per year in March, June, September and December describing the actual number of meter deployed compared to the forecasted number of meters to be deployed in the prior three months and project start to date.
	Deployment	6.2	**Customers Opting - Out of AMI meter deployment**	Number of customers since project start date and since last reporting period that have opted- out of the receiving an AMI meter.	.1% or less	End of 1st Quarter after meter deployment commences	Quarterly	The Company will report this metric quarterly describing the actual number of meter deployed compared to the forecasted number of meters to be deployed in the prior six months.

Rockland Electric Company AMI Metrics								
Category	**Service/Function**	**Ref #**	**Metric**	**Description**	**Goal**	**Report Start Date (At end of quarter specified)**	**Update Frequency**	**Notes**
Major Event	Major Event	7.1	**AMI Network Performance**	% of Access Points (AP) Available during Major Event	NA: Report # and % of AP Available vs Total APs Deployed	Starting in 3Q2018	Quarterly	The Company will be reporting this metric for each Major Event during the prior three months. Major Event is as defined in N.J.A.C. 14:5-1.2 Definitions
	Major Event	7.2	**Estimated Reduction in Major Event Duration**	Estimated reduction in major event duration due to AMI Program	TBD	End of 1Q 2020	Quarterly	The Company will be reporting this metric for each Major Event during the prior three months. Major Event is as defined in N.J.A.C. 14:5-1.2 Definitions
	Major Event	7.3	**Nested Outage Identification**	Number of nested outage identified during a Major Event	NA - Report # nested outages	End of 1st Quarter after meter deployment commences	Quarterly	The Company will be reporting this metric for each Major Event during the prior three months. Major Event is as defined in N.J.A.C. 14:5-1.2 Definitions
Project Management Report	Project Management Report	8	**Project Management Report**	Any issue not covered in above metrics	NA	End of 1st Quarter after meter deployment commences	Quarterly	The Company will be providing a Project Management Report detailing any pertinent issues surrounding deployment activities and any substantive changes to the AMI program as described in the Company's testimony and petition

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

Rockland Electric Company
Docket No. __________________

Exhibits

Volume II

ROCKLAND ELECTRIC COMPANY

EXHIBITS

VOLUME II

Tab No.	Exhibit No.	Subject
9	P-7	Depreciation Study
10	P-8	Cost of Service Study
11	JVW-1	James H. Vander Weide (Schedules 1-10)
12	YS-1	Yukari Saegusa

ROCKLAND ELECTRIC COMPANY

COMPARISON OF ACCRUALS APPLYING CURRENTLY APPROVED AND PROPOSED DEPRECIATION RATES
AS OF DECEMBER 31, 2018

					EXISTING			PROPOSED			
			ORIGINAL COST AS OF December 31, 2018	BOOK DEPRECIATION RESERVE	SURVIVOR CURVE	CALCULATED ANNUAL ACCRUAL AMOUNT	RATE	SURVIVOR CURVE	CALCULATED ANNUAL ACCRUAL AMOUNT	RATE	INCREASE (DECREASE)
		ACCOUNT (1)	(2)	(3)	(4)	(5)=(6)x(2)	(6)	(7)	(8)=(9)x(2)	(9)	(10)=(8)-(5)
		ELECTRIC PLANT									
		INTANGIBLE PLANT									
301000	301.00	ORGANIZATION	5,636.12	0	-	-	-	-	-	-	-
302000	302.00	FRANCHISES AND CONSENTS	441.59	0	-	-	-	-	-	-	-
		TOTAL INTANGIBLE PLANT	**6,077.71**	**0.00**		-	**-**		-	**-**	-
		TRANSMISSION PLANT									
350000	350.00	LAND AND LAND RIGHTS - EASEMENTS	1,440,974.69	0	-	-	-	-	-	-	-
350100	350.10	LAND AND LAND RIGHTS - FEE	387,670.89	0	-	-	-	-	-	-	-
352000	352.00	STRUCTURES AND IMPROVEMENTS	1,961,546.03	622,628	50-h2.00	39,231	2.00	60-R2	31,385	1.60	(7,846)
353000	353.00	STATION EQUIPMENT	14,590,663.21	4,863,610	35-h1.50	417,293	2.86	45-S0	345,799	2.37	(71,494)
354000	354.00	TOWERS AND FIXTURES	1,184,704.37	560,852	60-h3.00	19,785	1.67	70-R4	70,253	5.93	50,468
355000	355.00	POLES AND FIXTURES - WOOD	4,474,679.68	1,375,663	50-h3.00	89,494	2.00	55-R3	79,202	1.77	(10,292)
355100	355.10	POLES AND FIXTURES - STEEL	916,324.19	288,059	50-h3.00	18,326	2.00	55-R3	17,777	1.94	(549)
356000	356.00	OVERHEAD CONDUCTORS AND DEVICES	4,030,023.02	1,451,266	50-h2.00	80,600	2.00	65-R1.5	55,614	1.38	(24,986)
356100	356.10	OVERHEAD CONDUCTORS AND DEVICES - CLEARING	397,992.41	135,181	60-h2.00	6,646	1.67	65-R1.5	6,607	1.66	(39)
357000	357.00	UNDERGROUND CONDUIT	1,116,728.83	416,366	60-h2.00	18,649	1.67	45-R3	23,116	2.07	4,467
358000	358.00	UNDERGROUND CONDUCTORS AND DEVICES	1,074,720.86	505,567	50-h3.50	21,494	2.00	35-S3	29,555	2.75	8,061
359000	359.00	ROADS AND TRAILS	111,456.38	50,612	60-h3.00	1,861	1.67	65-R4	1,549	1.39	(312)
		TOTAL TRANSMISSION PLANT	**31,687,484.56**	**10,269,803.34**		**713,379**	**2.25**		**660,857**	**2.09**	**(52,522)**
		DISTRIBUTION PLANT									
360000	360.00	LAND AND LAND RIGHTS - EASEMENTS	180,609.34	0	-	-	-	-	-	-	-
360009	360.09	LAND AND LAND RIGHTS - EASEMENT (FUTURE USE)	41,660.00	0	-	-	-	-	-	-	-
360100	360.10	LAND AND LAND RIGHTS - FEE	2,713,001.98	0	-	-	-	-	-	-	-
360109	360.19	LAND AND LAND RIGHTS - FEE (FUTURE USE)	167,049.29	0	-	-	-	-	-	-	-
361000	361.00	STRUCTURES AND IMPROVEMENTS	4,625,487.04	1,233,543	55-h2.75	84,184	1.82	55-R3	88,347	1.91	4,163
362000	362.00	STATION EQUIPMENT	55,315,671.87	12,529,124	45-h1.75	1,228,008	2.22	45-S0	1,272,260	2.30	44,252
364000	364.00	POLES, TOWERS AND FIXTURES	53,126,118.68	7,936,606	59-h1.00	897,831	1.69	55-R1	1,041,272	1.96	143,441
365000	365.00	OVERHEAD CONDUCTORS AND DEVICES	62,057,541.83	10,397,094	70-h1.75	887,423	1.43	65-R1.5	992,921	1.60	105,498
365100	365.10	OVERHEAD CONDUCTORS AND DEVICES - CAPACITORS	1,785,642.87	499,693	30-h1.50	59,462	3.33	30-R1	60,712	3.40	1,250
366000	366.00	UNDERGROUND CONDUIT	21,119,335.96	4,733,870	75-h3.00	280,887	1.33	75-R3	280,887	1.33	0
367000	367.00	UNDERGROUND CONDUCTORS AND DEVICES	66,807,654.64	13,086,800	65-h3.00	1,028,838	1.54	60-R4	1,169,134	1.75	140,296
367100	367.10	UNDERGROUND CONDUCTORS AND DEVICES - CABLE CURE	2,160,120.31	770,054	65-h3.50	33,266	1.54	60-R4	34,130	1.58	864
368100	368.10	LINE TRANSFORMERS - OVERHEAD	15,675,778.89	3,581,924	50-h1.00	313,516	2.00	45-R0.5	387,192	2.47	73,676
368200	368.20	LINE TRANSFORMERS - OVERHEAD INSTALLATIONS	9,085,538.15	1,505,964	50-h1.00	181,711	2.00	45-R0.5	214,419	2.36	32,708
368300	368.30	LINE TRANSFORMERS - UNDERGROUND	11,015,573.55	2,458,352	50-h1.00	220,311	2.00	45-R0.5	263,272	2.39	42,961
368400	368.40	LINE TRANSFORMERS - UNDERGROUND INSTALLATIONS	3,556,294.05	441,038	50-h1.00	71,126	2.00	45-R0.5	81,439	2.29	10,313
369100	369.10	SERVICES - OVERHEAD	6,009,238.99	2,440,275	60-h2.50	100,354	1.67	65-R3	94,345	1.57	(6,009)
369200	369.20	SERVICES - UNDERGROUND	15,677,838.59	5,258,215	60-h3.50	261,820	1.67	65-R3	228,896	1.46	(32,924)
370100	370.10	METERS - ELECTROMECHANICAL	2,156,324.77	845,525	25-h1.00	86,253	4.00	25-L0	77,843	3.61	(8,410)
370110	370.11	METERS - SOLID STATE	1,918,872.54	309,269	20-h1.00	95,944	5.00	20-S2.5	123,767	6.45	27,823
370120	370.12	METERS - AMI	4,246,309.01	35,694	20-h2.25	212,315	5.00	20-S2.5	212,315	5.00	0
370150	370.15	METERS - UNRECOVERED ELECTROMECHANICAL PURCHASES	0.00	0	25-h1.00	0	4.00	25-L0	0	4.00	0
370160	370.16	METERS - UNRECOVERED SOLID STATE PURCHASES	0.00	0	20-h1.00	0	5.00	20-S2.5	0	5.00	0
370200	370.20	METER INSTALLATIONS - ELECTROMECHANICAL	1,088,843.04	459,472	25-h1.00	43,554	4.00	25-L0	39,198	3.60	(4,356)
370210	370.21	METER INSTALLATIONS - SOLID STATE	2,635,079.47	415,222	20-h1.00	131,754	5.00	20-S2.5	159,949	6.07	28,195
370220	370.22	METER INSTALLATIONS - AMI	2,391,720.79	29,467	20-h2.25	119,586	5.00	20-S2.5	119,586	5.00	0
370250	370.25	METER INSTALLATIONS - UNRECOVERED ELECTROMECHANICAL PURCHASES	0.00	0	25-h1.00	0	4.00	25-L0	0	4.00	0
370260	370.26	METER INSTALLATIONS - UNRECOVERED SOLID STATE PURCHASES	0.00	0	20-h1.00	0	5.00	20-S2.5	0	5.00	0
371000	371.00	INSTALLATIONS ON CUSTOMERS' PREMISES	582,740.41	222,161	40-h2.50	14,569	2.50	35-R0.5	14,685	2.52	116
373100	373.10	STREET LIGHTING AND SIGNAL SYSTEMS - OVERHEAD	3,897,634.46	855,539	45-h1.00	86,527	2.22	40-R0.5	112,252	2.88	25,725
373200	373.20	STREET LIGHTING AND SIGNAL SYSTEMS - UNDERGROUND	1,513,599.33	369,880	45-h1.00	33,602	2.22	40-R0.5	42,684	2.82	9,082
		TOTAL DISTRIBUTION PLANT	**351,551,279.85**	**70,414,780.02**		**6,472,841**	**1.84**		**7,111,505**	**2.02**	**638,664**

ROCKLAND ELECTRIC COMPANY

COMPARISON OF ACCRUALS APPLYING CURRENTLY APPROVED AND PROPOSED DEPRECIATION RATES
AS OF DECEMBER 31, 2018

					EXISTING			PROPOSED			
			ORIGINAL COST AS OF December 31, 2018	BOOK DEPRECIATION RESERVE	SURVIVOR CURVE	CALCULATED ANNUAL ACCRUAL AMOUNT	RATE	SURVIVOR CURVE	CALCULATED ANNUAL ACCRUAL AMOUNT	RATE	INCREASE (DECREASE)
		ACCOUNT (1)	(2)	(3)	(4)	(5)=(6)x(2)	(6)	(7)	(8)=(9)x(2)	(9)	(10)=(8)-(5)
		GENERAL PLANT									
389100	389.10	LAND AND LAND RIGHTS - FEE	154,414.77	0	-	-	-	-	-	-	-
390000	390.00	STRUCTURES AND IMPROVEMENTS	702,344.12	237,379	45-h1.75	15,592	2.22	45-S0	15,803	2.25	211
390104	390.14	STRUCTURES AND IMPROVEMENTS - LETHBRIDGE PLAZA	235,554.08	177,410	-	17,539 *	-	-	17,539 *	-	0
		OFFICE FURNITURE AND EQUIPMENT									
391100	391.10	FURNITURE	3,614.57	(11,847)	20-SQ	181	5.00	20-SQ	181	5.00	0
391200	391.20	BUSINESS MACHINES	-	(5,479)	15-SQ	-	6.67	15-SQ	-	6.67	-
391700	391.70	EDP EQUIPMENT	24,780.87	21,307	8-SQ	3,098	12.50	8-SQ	3,098	12.50	0
		TOTAL OFFICE FURNITURE AND EQUIPMENT	28,395	3,982		3,279	11.55		3,279	11.55	0
392400	392.40	TRAILERS AND TRUCK MOUNTED EQUIPMENT	(30.55)	0	-	-	-	-	-	-	-
393000	393.00	STORES EQUIPMENT	2,025.54	1,299	20-SQ	101	5.00	20-SQ	101	5.00	0
394000	394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	456,379.85	82,075	20-SQ	22,819	5.00	20-SQ	22,819	5.00	0
394200	394.20	GARAGE EQUIPMENT	68,132.51	47,858	30-SQ	2,269	3.33	30-SQ	2,269	3.33	0
395000	395.00	LABORATORY EQUIPMENT	224,222.33	57,182	25-SQ	8,969	4.00	25-SQ	8,969	4.00	0
396000	396.00	POWER OPERATED EQUIPMENT	-	(36,634)	20-SQ	-	5.00	20-SQ	-	5.00	-
397000	397.00	COMMUNICATION EQUIPMENT	7,455,702.97	2,187,908	15-SQ	497,295	6.67	15-SQ	497,295	6.67	0
397100	397.10	COMMUNICATION EQUIPMENT - TELEPHONE SYSTEM COMPUTER	40,248.05	20,266	8-SQ	5,031	12.50	8-SQ	5,031	12.50	0
397200	397.20	COMMUNICATION EQUIPMENT - TELEPHONE SYSTEM EQUIPMENT	27,170.98	1,128	15-SQ	1,812	6.67	15-SQ	1,812	6.67	0
398000	398.00	MISCELLANEOUS EQUIPMENT	281,187.59	39,616	20-SQ	14,059	5.00	20-SQ	14,059	5.00	0
		TOTAL GENERAL PLANT	**9,675,747.68**	**2,819,468.55**		**588,765**	**6.08**		**588,976**	**6.09**	**211**
		TOTAL ELECTRIC PLANT EXCEPT UNALLOCATED	**392,920,590**	**83,504,052**		**7,774,985**	**1.98**		**8,361,338**	**2.13**	**586,353**
		COMPOSITE RATE IN TOTAL				**1.98%**			**2.13%**		
		COMPOSITE RATE W/O TRANSMISSION				**1.95%**			**2.13%**		
		UNALLOCATED RESERVE									
399100	399100	UNALLOCATED RESERVE - 2017 Case		8,585,752							
399030	399030	COST OF REMOVAL RESERVE		(2,719,856)							
399080	399080	UNALLOCATED RESERVE - 2015 Case		(336,319)							
399090	399090	UNALLOCATED RESERVE - 2017 Case		(203,934)							
		TOAL UNALLOCATED		5,325,643							
		TOTAL COMPANY	**392,920,590**	**88,829,695**							

* REMAINING LIFE AMORTIZATION BASED ON LEASE TERM.

ROCKLAND ELECTRIC COMPANY

COMPUTATION OF THE ANNUAL NET SALVAGE ALLOWANCE

	2016	2017	2018	Total	Average
Intangible Plant	-	-		-	-
Distribution	1,048,053	2,916,496	1,386,865	5,351,415	1,783,805
Electric Plant Held for Future Use	-	-		-	-
General Plant					
Total Company	**1,048,053**	**2,916,496**	**1,386,865**	**5,351,415**	**1,783,805**

Incremental Net Salvage

Average 2016-2018 (Rounded)	1,784,000.00
Current Allowance	1,024,404.00
Increase (decrease) in Allowance	759,596.00

Exhibit P-7
Schedule 3

ROCKLAND ELECTRIC COMPANY

MAHWAH, NEW JERSEY

2017 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2017

Prepared by:

Gannett Fleming

*Excellence Delivered **As Promised***

ROCKLAND ELECTRIC COMPANY

Mahwah, New Jersey

2017 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS
RELATED TO ELECTRIC PLANT
AS OF DECEMBER 31, 2017

GANNETT FLEMING VALUATION AND RATE CONSULTANTS, LLC
Harrisburg, Pennsylvania

Gannett Fleming

Excellence Delivered **As Promised**

April 9, 2019

Rockland Electric Company
4 Irving Place – 3rd Floor NW
New York, NY 10003

Attention Matthew Kahn
Section Manager – Tax Department

Ladies and Gentlemen:

Pursuant to your request, we have conducted a depreciation study related to the electric plant of Rockland Electric Company ("Company") as of December 31, 2017. The attached report presents a description of the methods used in the estimation of depreciation, the summary of annual depreciation accrual rates, the statistical support for the life and net salvage estimates and the detailed tabulations of annual depreciation.

Respectfully submitted,

GANNETT FLEMING VALUATION
AND RATE CONSULTANTS, LLC

Ned W Allis

NED W. ALLIS
Vice President

NWA:mle

064161.100

Gannett Fleming Valuation and Rate Consultants, LLC
P.O. Box 67100 • Harrisburg, PA 17106-7100 | 207 Senate Avenue • Camp Hill, PA 17011-2316
t: 717.763.7211 • f: 717.763.4590
www.gfvrc.com

TABLE OF CONTENTS

TABLE OF CONTENTS, cont

ROCKLAND ELECTRIC COMPANY

DEPRECIATION STUDY

EXECUTIVE SUMMARY

Pursuant to Rockland Electric Company's ("RECO" or "Company") request, Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming") conducted a service life study related to RECO's electric plant based on historical data through December 31, 2016. The purpose of this study was to determine the survivor curve estimates to be used for the calculation of annual depreciation rates and accruals.

The survivor curve estimates set forth in this study are the same as those recommended for RECO's affiliate company Orange and Rockland Utilities ("ORU") in ORU's 2016 Depreciation Study. The historical data used for the service life analysis for both the ORU study and RECO's study are the same and include historical transactions for both companies, and the expectation is that both companies will experience similar service lives. Net salvage estimates have not been recommended for RECO in this study, as utilities in New Jersey have used a normalized expense approach to net salvage in recent years.

Gannett Fleming recommends the calculated annual depreciation accrual rates set forth herein apply specifically to electric and common plant in service as of December 31, 2017 as summarized by Table 1 of the study. The recommended depreciation rates are based on the remaining life technique, which is a change from the previous study, but is the most common depreciation technique in New Jersey. The net salvage normalized expense amounts are presented on Table 2 of the Study. Supporting analysis and calculations are provided within the study.

The study results set forth an annual depreciation expense of $7.1 million when applied to depreciable plant balances as of December 31, 2017. The results of the study, including the reserve variations (both amounts and expressed as a percentage of the theoretical reserve) are summarized at the functional level as follows:

SUMMARY OF ORIGINAL COST, PROPOSED ACCRUAL RATES AND AMOUNTS

FUNCTION	ORIGINAL COST AS OF DECEMBER 31, 2017	ACCRUAL RATE	ACCRUAL AMOUNT
ELECTRIC PLANT			
Transmission Plant	$ 29,313,193.75	2.21	$ 647,524
Distribution Plant	321,082,423.38	2.01	6,454,034
General Plant	689,261.10	2.25	15,477
Total Depreciable Electric Plant	**$351,084,878.23**	**2.03**	**$7,117,035**

PART I. INTRODUCTION

ROCKLAND ELECTRIC COMPANY

DEPRECIATION STUDY

PART I. INTRODUCTION

SCOPE

This report sets forth the results of the depreciation study for Rockland Electric Company ("RECO"), to determine the annual depreciation accrual rates and amounts for book purposes applicable to the original cost of electric plant as of December 31, 2017. The rates and amounts are based on the straight line remaining life method of depreciation. This report also describes the concepts, methods and judgments which underlie the recommended annual depreciation accrual rates related to electric plant in service as of December 31, 2017.

The service life estimates resulting from the study were based on informed judgment which incorporated analyses of historical plant retirement data as recorded through 2016; a review of Company practice and outlook as they relate to plant operation and retirement; and consideration of current practice in the electric industry, including knowledge of service lives used for other electric companies.

PLAN OF REPORT

Part I, Introduction, contains statements with respect to the plan of the report, and the basis of the study. Part II, Estimation of Survivor Curves, presents descriptions of the considerations and the methods used in the service life and net salvage studies. Part III, Service Life Considerations, presents the factors and judgment utilized in the average service life analysis. Part IV, Net Salvage Considerations, presents the judgment utilized for the net salvage study. Part V, Calculation of Annual and Accrued Depreciation, describes the procedures used in the calculation of group depreciation.

Part VI, Results of Study, presents summaries by depreciable group of annual depreciation accrual rates and amounts, as well as composite remaining lives. Part VII, Service Life Statistics presents the statistical analysis of service life estimates and Part VIII, Detailed Depreciation Calculations presents the detailed tabulations of annual and accrued depreciation.

BASIS OF THE STUDY

Depreciation

Depreciation, in public utility regulation, is the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among causes to be given consideration are wear and tear, deterioration, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and the requirements of public authorities.

Depreciation, as used in accounting, is a method of distributing fixed capital costs, less net salvage, over a period of time by allocating annual amounts to expense. Each annual amount of such depreciation expense is part of that year's total cost of providing utility service. Normally, the period of time over which the fixed capital cost is allocated to the cost of service is equal to the period of time over which an item renders service, that is, the item's service life. The most prevalent method of allocation is to distribute an equal amount of cost to each year of service life. This method is known as the straight-line method of depreciation.

For most accounts, the annual depreciation was calculated by the straight-line method using the average service life procedure and the remaining life basis. The calculations were based on original cost, attained ages, and estimates of service lives and net salvage.

For certain General Plant accounts, the annual depreciation is based on amortization accounting.

The straight-line method, average service life procedure is a commonly used depreciation calculation procedure that has been widely accepted in jurisdictions throughout North America, including New Jersey. Gannett Fleming recommends its use in this study. Amortization accounting is used for certain General Plant accounts because of the disproportionate plant accounting effort required when compared to the minimal original cost of the large number of items in these accounts. An explanation of the calculation of annual and accrued amortization is presented beginning on page V-4 of the report.

Service Life Estimates

The service life estimates used in the depreciation and amortization calculations were based on informed judgment which incorporated a review of management's plans, policies and outlook, a general knowledge of the electric utility industry, and comparisons of the service life and net salvage estimates from our studies of other electric utilities. The use of survivor curves to reflect the expected dispersion of retirement provides a consistent method of estimating depreciation for utility plant. Iowa type survivor curves were used to depict the estimated survivor curves for the plant accounts not subject to amortization accounting.

The procedure for estimating service lives consisted of compiling historical data for the plant accounts or depreciable groups, analyzing this history through the use of widely accepted techniques, and forecasting the survivor characteristics for each depreciable group on the basis of interpretations of the historical data analyses and the probable future. The combination of the historical experience and the estimated future yielded estimated survivor curves from which the average service lives were derived.

PART II. ESTIMATION OF SURVIVOR CURVES

PART II. ESTIMATION OF SURVIVOR CURVES

The calculation of annual depreciation based on the straight-line method requires the estimation of survivor curves and the selection of group depreciation procedures. The estimation of survivor curves is discussed below and the development of net salvage is discussed in later sections of this report.

SURVIVOR CURVES

The use of an average service life for a property group implies that the various units in the group have different lives. Thus, the average life may be obtained by determining the separate lives of each of the units, or by constructing a survivor curve by plotting the number of units which survive at successive ages.

The survivor curve graphically depicts the amount of property existing at each age throughout the life of an original group. From the survivor curve, the average life of the group, the remaining life expectancy, the probable life, and the frequency curve can be calculated. In Figure 1, a typical smooth survivor curve and the derived curves are illustrated. The average life is obtained by calculating the area under the survivor curve, from age zero to the maximum age, and dividing this area by the ordinate at age zero. The remaining life expectancy at any age can be calculated by obtaining the area under the curve, from the observation age to the maximum age, and dividing this area by the percent surviving at the observation age. For example, in Figure 1, the remaining life at age 30 is equal to the crosshatched area under the survivor curve divided by 29.5 percent surviving at age 30. The probable life at any age is developed by adding the age and remaining life. If the probable life of the property is calculated for each year of age, the probable life curve shown in the chart can be developed. The frequency curve presents the number of units retired in each age interval. It is derived by obtaining the differences between the amount of property surviving at the beginning and at the end of each interval.

The recommended survivor curves in this study are developed from a retirement rate analysis of historical retirement history and are based on Iowa type survivor curves. A discussion of the concepts of survivor curves, including both the h-system curves and the more widely used Iowa curves, as well as a discussion of the development of survivor curves using the retirement rate method is presented below.

Iowa Type Curves

The range of survivor characteristics usually experienced by utility and industrial properties is encompassed by a system of generalized survivor curves known as the Iowa type curves. There are four families in the Iowa system, labeled in accordance with the location of the modes of the retirements in relationship to the average life and the relative height of the modes. The left moded curves, presented in Figure 2, are those in which the greatest frequency of retirement occurs to the left of, or prior to, average service life. The symmetrical moded curves, presented in Figure 3, are those in which the greatest frequency of retirement occurs at average service life. The right moded curves, presented in Figure 4, are those in which the greatest frequency occurs to the right of, or after, average service life. The origin moded curves, presented in Figure 5, are those in which the greatest frequency of retirement occurs at the origin, or immediately after age zero. The letter designation of each family of curves (L, S, R or O) represents the location of the mode of the associated frequency curve with respect to the average service life. The numbers represent the relative heights of the modes of the frequency curves within each family.

The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observation and classification of the ages at which industrial property had been retired. A report of the study which resulted in the classification of property survivor characteristics into 18 type curves, which constitute three of the four families, was published in 1935 in the form of the Experiment Station's Bulletin 125.

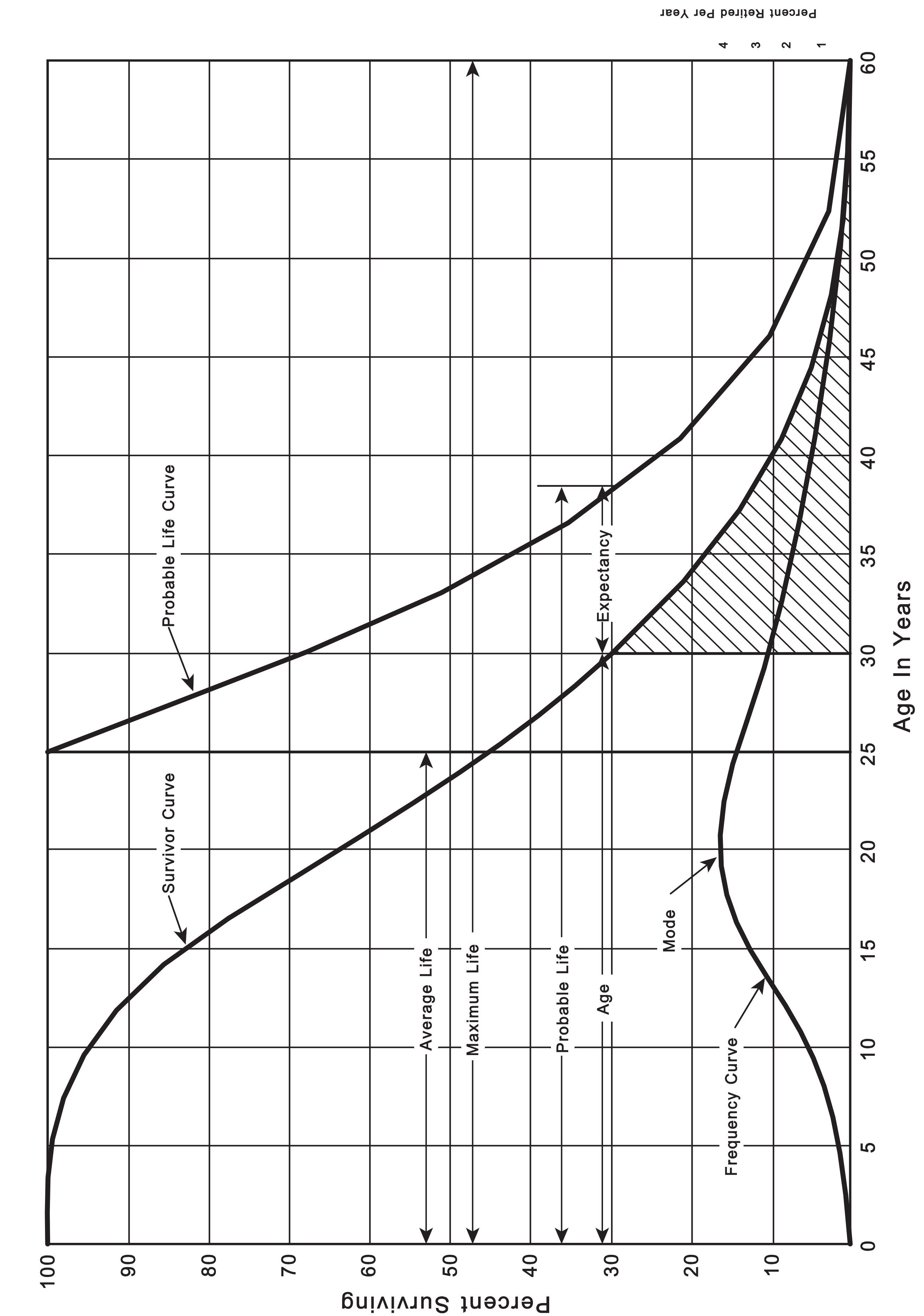


Figure 1. A Typical Survivor Curve and Derived Curves

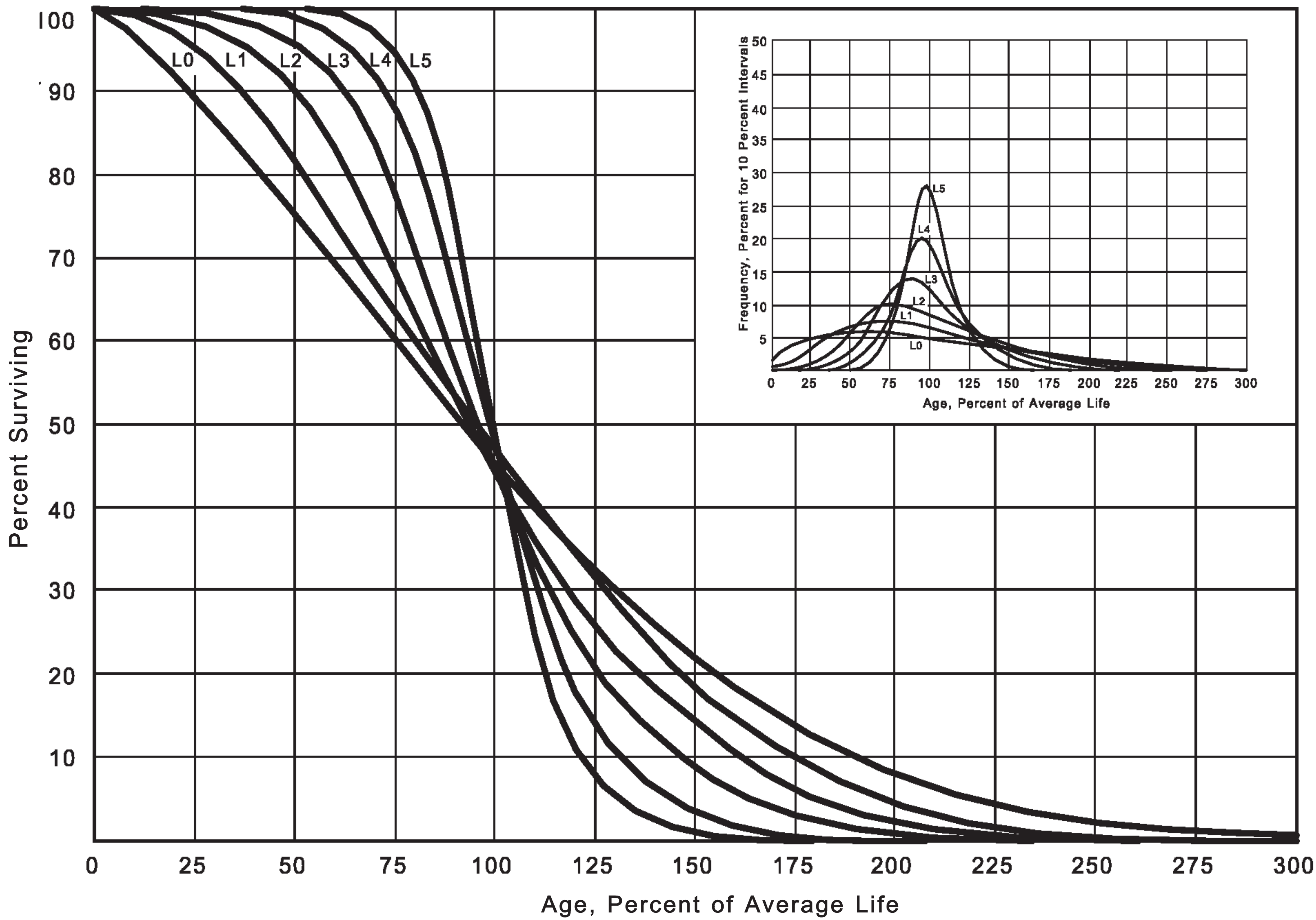


Figure 2. Left Modal or "L" Iowa Type Survivor Curves

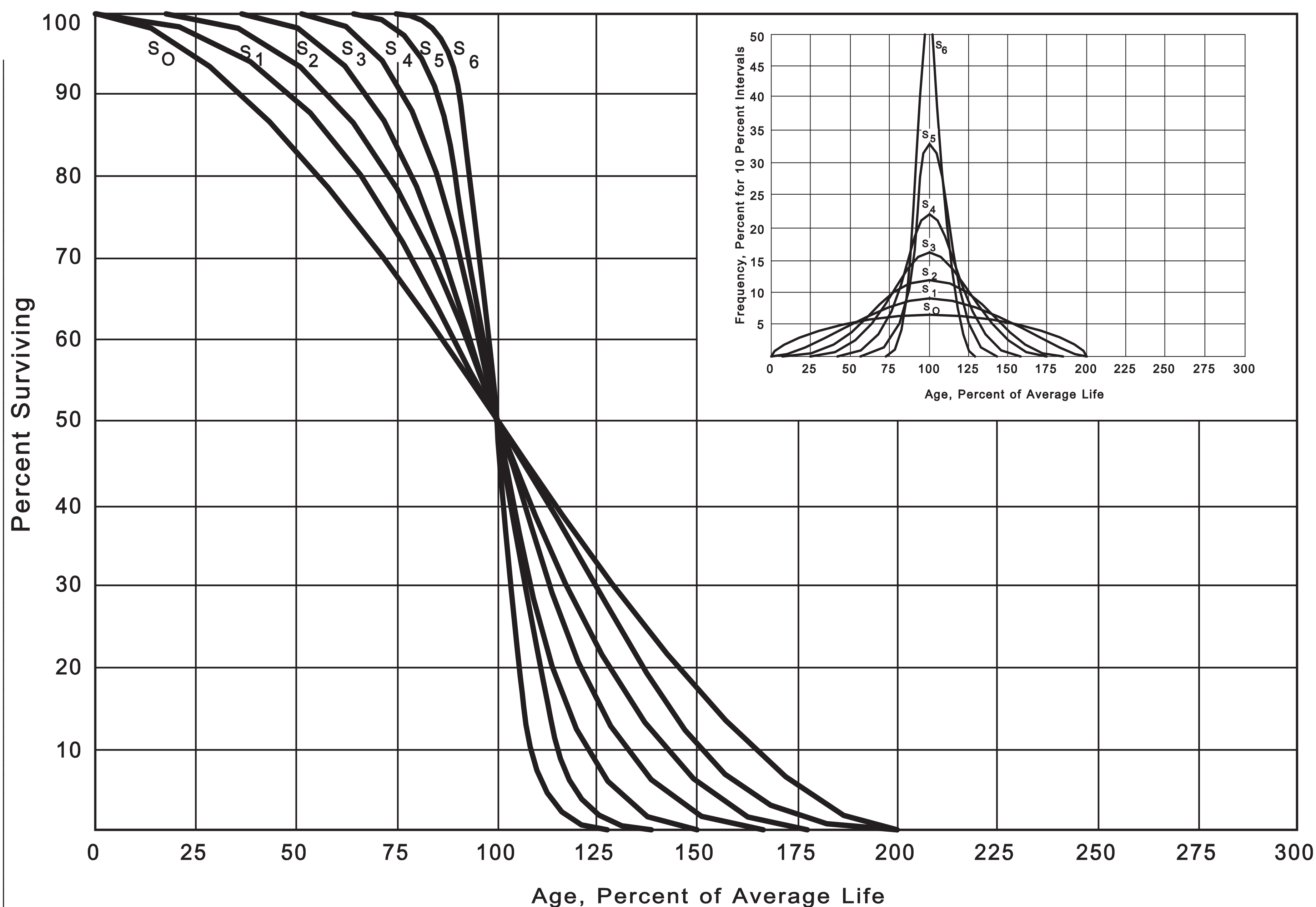


Figure 3. Symmetrical or "S" Iowa Type Survivor Curves

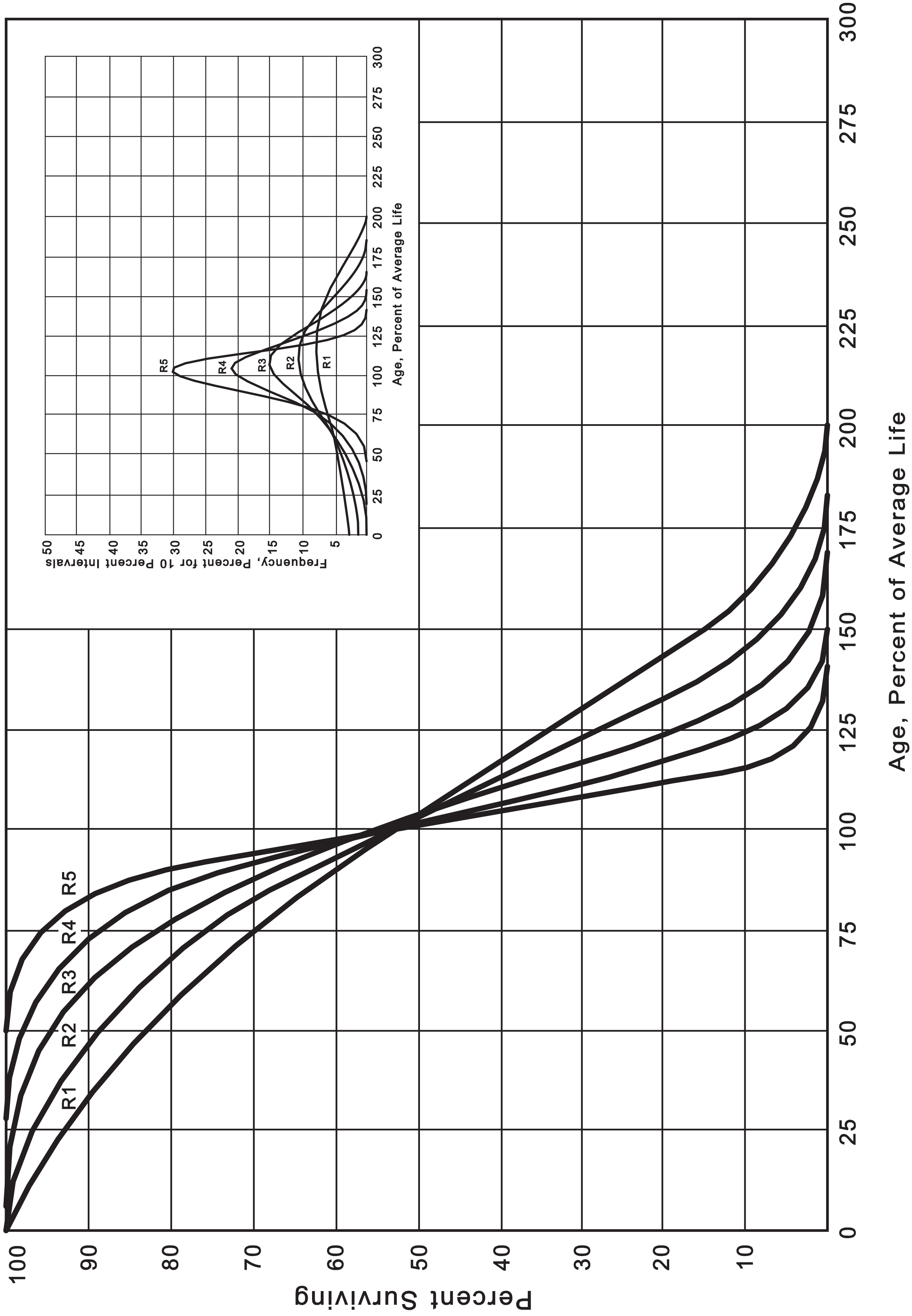


Figure 4. Right Modal or "R" Iowa Type Survivor Curves

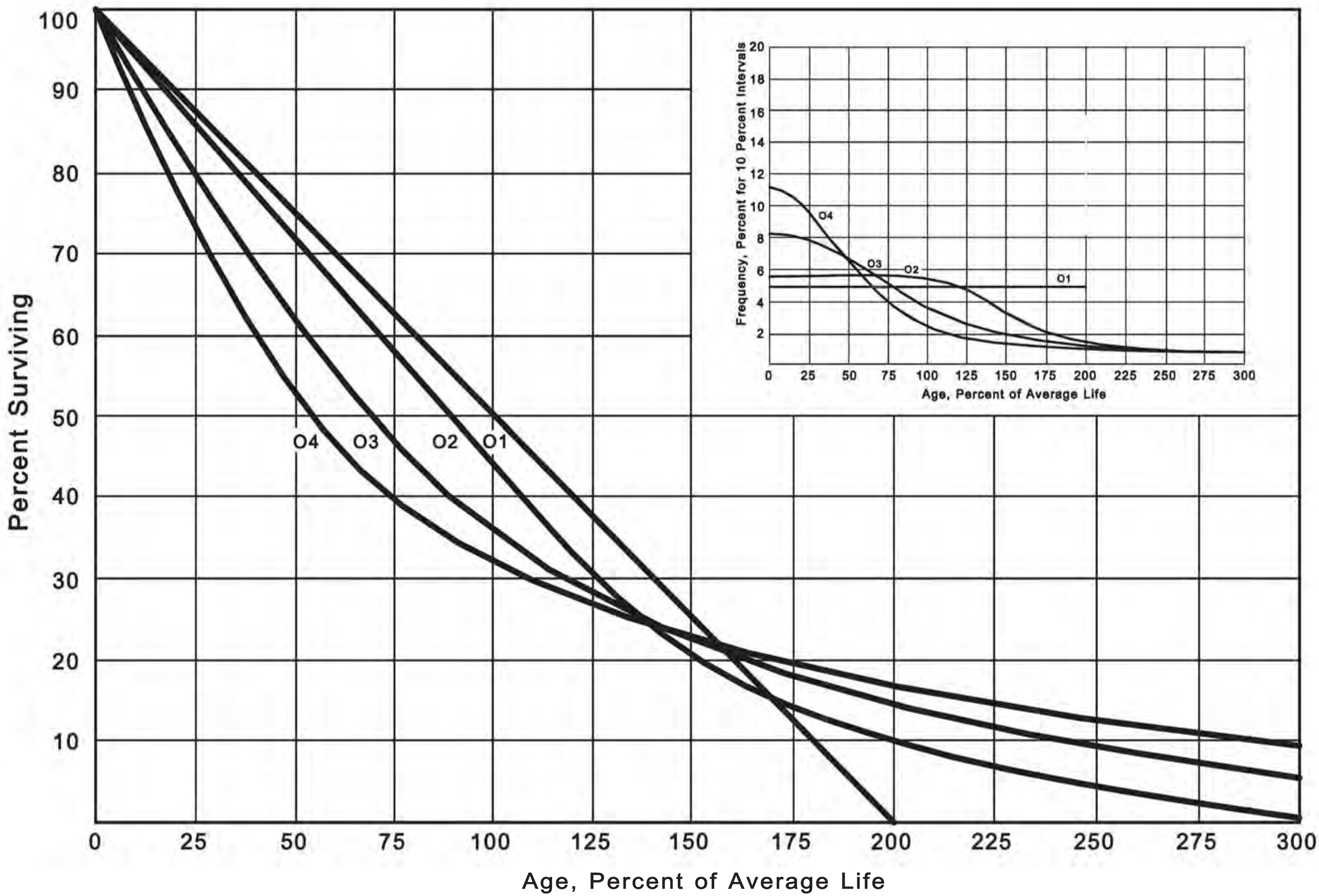


Figure 5. Origin Modal or "O" Iowa Type Survivor Curves

These curve types have also been presented in subsequent Experiment Station bulletins and in the text, "Engineering Valuation and Depreciation."[1] In 1957, Frank V. B. Couch, Jr., an Iowa State College graduate student submitted a thesis presenting his development of the fourth family consisting of the four O type survivor curves.

Retirement Rate Method of Analysis

The retirement rate method is an actuarial method of deriving survivor curves using the average rates at which property of each age group is retired. The method relates to property groups for which aged accounting experience is available and is the method used to develop the original stub survivor curves in this study. The method (also known as the annual rate method) is illustrated through the use of an example in the following text, and is also explained in several publications, including "Statistical Analyses of Industrial Property Retirements", [2] "Engineering Valuation and Depreciation," [3] and "Depreciation Systems."[4]

The average rate of retirement used in the calculation of the percent surviving for the survivor curve (life table) requires two sets of data: first, the property retired during a period of observation, identified by the property's age at retirement; and second, the property exposed to retirement at the beginning of the age intervals during the same period. The period of observation is referred to as the experience band, and the band of years which represent the installation dates of the property exposed to retirement during the experience band is referred to as the placement band. An example of the calculations

[1] Marston, Anson, Robley Winfrey and Jean C. Hempstead. Engineering Valuation and Depreciation, 2nd Edition. New York, McGraw-Hill Book Company. 1953.

[2] Winfrey, Robley, Statistical Analyses of Industrial Property Retirements. Iowa State College Engineering Experiment Station, Bulletin 125. 1935.

[3] Marston, Anson, Robley Winfrey, and Jean C. Hempstead, Supra Note 1.

[4] Wolf, Frank K. and W. Chester Fitch. Depreciation Systems. Iowa State University Press. 1994.

used in the development of a life table follows. The example includes schedules of annual aged property transactions, a schedule of plant exposed to retirement, a life table and illustrations of smoothing the stub survivor curve.

Schedules of Annual Transactions in Plant Records

The property group used to illustrate the retirement rate method is observed for the experience band 2008-2017 during which there were placements during the years 2003-2017. In order to illustrate the summation of the aged data by age interval, the data were compiled in the manner presented in Schedules 1 and 2 on pages II-11 and II-12. In Schedule 1, the year of installation (year placed) and the year of retirement are shown. The age interval during which a retirement occurred is determined from this information. In the example which follows, $10,000 of the dollars invested in 2003 were retired in 2008. The $10,000 retirement occurred during the age interval between 4½ and 5½ years on the basis that approximately one-half of the amount of property was installed prior to and subsequent to July 1 of each year. That is, on the average, property installed during a year is placed in service at the midpoint of the year for the purpose of the analysis. All retirements also are stated as occurring at the midpoint of a one-year age interval of time, except the first age interval which encompasses only one- half year.

The total retirements occurring in each age interval in a band are determined by summing the amounts for each transaction year-installation year combination for that age interval. For example, the total of $143,000 retired for age interval 4½-5½ is the sum of the retirements entered on Schedule 1 immediately above the stair step line drawn on the table beginning with the 2008 retirements of 2003 installations and ending with the 2017 retirements of the 2012 installations. Thus, the total amount of 143 for age interval 4½-5½ equals the sum of:

$$10 + 12 + 13 + 11 + 13 + 13 + 15 + 17 + 19 + 20.$$

SCHEDULE 1. RETIREMENTS FOR EACH YEAR 2008-2017
SUMMARIZED BY AGE INTERVAL

Experience Band 2008-2017

Placement Band 2003-2017

Year	Retirements, Thousands of Dollars During Year										Total During	Age
Placed	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	Age Interval	Interval
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2003	10	11	12	13	14	16	23	24	25	26	26	13½-14½
2004	11	12	13	15	16	18	20	21	22	19	44	12½-13½
2005	11	12	13	14	16	17	19	21	22	18	64	11½-12½
2006	8	9	10	11	11	13	14	15	16	17	83	10½-11½
2007	9	10	11	12	13	14	16	17	19	20	93	9½-10½
2008	4	9	10	11	12	13	14	15	16	20	105	8½-9½
2009		5	11	12	13	14	15	16	18	20	113	7½-8½
2010			6	12	13	15	16	17	19	19	124	6½-7½
2011				6	13	15	16	17	19	19	131	5½-6½
2012					7	14	16	17	19	20	143	4½-5½
2013						8	18	20	22	23	146	3½-4½
2014							9	20	22	25	150	2½-3½
2015								11	23	25	151	1½-2½
2016									11	24	153	½-1½
2017										13	80	0-½
Total	53	68	86	106	128	157	196	231	273	308	1,606	

SCHEDULE 2. OTHER TRANSACTIONS FOR EACH YEAR 2008-2017
SUMMARIZED BY AGE INTERVAL

Experience Band 2008-2017 Placement Band 2003-2017

Year Placed	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	Total During Age Interval	Age Interval
	Acquisitions, Transfers and Sales, Thousands of Dollars During Year											
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2003	-	-	-	-	-	-	60[a]	-	-	-	-	13½-14½
2004	-	-	-	-	-	-	-	-	-	-	-	12½-13½
2005	-	-	-	-	-	-	-	-	-	-	-	11½-12½
2006	-	-	-	-	-	-	-	(5)[b]	-	-	60	10½-11½
2007	-	-	-	-	-	-	-	6[a]	-	-	-	9½-10½
2008	-	-	-	-	-	-	-	-	-	-	(5)	8½-9½
2009		-	-	-	-	-	-	-	-	-	6	7½-8½
2010			-	-	-	-	-	-	-	-	-	6½-7½
2011				-	-	-	-	(12)[b]	-	-	-	5½-6½
2012					-	-	-	-	22[a]	-	-	4½-5½
2013						-	-	(19)[b]	-	-	10	3½-4½
2014							-	-	-	-	-	2½-3½
2015								-	-	(102)[c]	(121)	1½-2½
2016									-	-	-	½-1½
2017											-	0-½
Total	-	-	-	-	-	-	60	(30)	22	(102)	(50)	

[a] Transfer Affecting Exposures at Beginning of Year
[b] Transfer Affecting Exposures at End of Year
[c] Sale with Continued Use
Parentheses Denote Credit Amount.

In Schedule 2, other transactions which affect the group are recorded in a similar manner. The entries illustrated include transfers and sales. The entries which are credits to the plant account are shown in parentheses. The items recorded on this schedule are not totaled with the retirements but are used in developing the exposures at the beginning of each age interval.

Schedule of Plant Exposed to Retirement

The development of the amount of plant exposed to retirement at the beginning of each age interval is illustrated in Schedule 3 on page II-14. The surviving plant at the beginning of each year from 2008 through 2017 is recorded by year in the portion of the table headed "Annual Survivors at the Beginning of the Year." The last amount entered in each column is the amount of new plant added to the group during the year. The amounts entered in Schedule 3 for each successive year following the beginning balance or addition are obtained by adding or subtracting the net entries shown on Schedules 1 and 2. For the purpose of determining the plant exposed to retirement, transfers-in are considered as being exposed to retirement in this group at the beginning of the year in which they occurred, and the sales and transfers-out are considered to be removed from the plant exposed to retirement at the beginning of the following year. Thus, the amounts of plant shown at the beginning of each year are the amounts of plant from each placement year considered to be exposed to retirement at the beginning of each successive transaction year. For example, the exposures for the installation year 2013 are calculated in the following manner:

Exposures at age 0	= amount of addition	= $750,000
Exposures at age ½	= $750,000 - $ 8,000	= $742,000
Exposures at age 1½	= $742,000 - $18,000	= $724,000
Exposures at age 2½	= $724,000 - $20,000 - $19,000	= $685,000
Exposures at age 3½	= $685,000 - $22,000	= $663,000

SCHEDULE 3. PLANT EXPOSED TO RETIREMENT
JANUARY 1 OF EACH YEAR 2008-2017
SUMMARIZED BY AGE INTERVAL

Experience Band 2008-2017 | Placement Band 2003-2017

Year	Exposures, Thousands of Dollars										Total at	
	Annual Survivors at the Beginning of the Year										Beginning of	Age
Placed	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	Age Interval	Interval
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2003	255	245	234	222	209	195	239	216	192	167	167	13½-14½
2004	279	268	256	243	228	212	194	174	153	131	323	12½-13½
2005	307	296	284	271	257	241	224	205	184	162	531	11½-12½
2006	338	330	321	311	300	289	276	262	242	226	823	10½-11½
2007	376	367	357	346	334	321	307	297	280	261	1,097	9½-10½
2008	420[a]	416	407	397	386	374	361	347	332	316	1,503	8½-9½
2009		460[a]	455	444	432	419	405	390	374	356	1,952	7½-8½
2010			510[a]	504	492	479	464	448	431	412	2,463	6½-7½
2011				580[a]	574	561	546	530	501	482	3,057	5½-6½
2012					660[a]	653	639	623	628	609	3,789	4½-5½
2013						750[a]	742	724	685	663	4,332	3½-4½
2014							850[a]	841	821	799	4,955	2½-3½
2015								960[a]	949	926	5,719	1½-2½
2016									1,080[a]	1,069	6,579	½-1½
2017										1,220[a]	7,490	0-½
Total	1,975	2,382	2,824	3,318	3,872	4,494	5,247	6,017	6,852	7,799	44,780	

[a]Additions during the year

For the entire experience band 2008-2017, the total exposures at the beginning of an age interval are obtained by summing diagonally in a manner similar to the summing of the retirements during an age interval (Table 1). For example, the figure of 3,789, shown as the total exposures at the beginning of age interval 4½-5½, is obtained

by summing:

255 + 268 + 284 + 311 + 334 + 374 + 405 + 448 + 501 + 609.

Original Life Table

The original life table, illustrated in Schedule 4 on page II-16, is developed from the totals shown on the schedules of retirements and exposures, Schedules 1 and 3, respectively. The exposures at the beginning of the age interval are obtained from the corresponding age interval of the exposure schedule, and the retirements during the age interval are obtained from the corresponding age interval of the retirement schedule.

The retirement ratio is the result of dividing the retirements during the age interval by the exposures at the beginning of the age interval. The percent surviving at the beginning of each age interval is derived from survivor ratios, each of which equals one minus the retirement ratio. The percent surviving is developed by starting with 100% at age zero and successively multiplying the percent surviving at the beginning of each interval by the survivor ratio, i.e., one minus the retirement ratio for that age interval. The calculations necessary to determine the percent surviving at age 5½ are as follows:

Percent surviving at age 4½	=	88.15			
Exposures at age 4½	=	3,789,000			
Retirements from age 4½ to 5½	=	143,000			
Retirement Ratio	=	143,000 ÷	3,789,000	=	0.0377
Survivor Ratio	=	1.000 -	0.0377	=	0.9623 Percent
surviving at age 5½	=	(88.15) x	(0.9623)	=	84.83

The totals of the exposures and retirements (columns 2 and 3) are shown for the purpose of checking with the respective totals in Schedules 1 and 3. The ratio of the total retirements to the total exposures, other than for each age interval, is meaningless.

SCHEDULE 4. ORIGINAL LIFE TABLE
CALCULATED BY THE RETIREMENT RATE METHOD

Experience Band 2008-2017 Placement Band 2003-2017

(Exposure and Retirement Amounts are in Thousands of Dollars)

Age at Beginning of Interval	Exposures at Beginning of Age Interval	Retirements During Age Interval	Retirement Ratio	Survivor Ratio	Percent Surviving at Beginning of Age Interval
(1)	(2)	(3)	(4)	(5)	(6)
0.0	7,490	80	0.0107	0.9893	100.00
0.5	6,579	153	0.0233	0.9767	98.93
1.5	5,719	151	0.0264	0.9736	96.62
2.5	4,955	150	0.0303	0.9697	94.07
3.5	4,332	146	0.0337	0.9663	91.22
4.5	3,789	143	0.0377	0.9623	88.15
5.5	3,057	131	0.0429	0.9571	84.83
6.5	2,463	124	0.0503	0.9497	81.19
7.5	1,952	113	0.0579	0.9421	77.11
8.5	1,503	105	0.0699	0.9301	72.65
9.5	1,097	93	0.0848	0.9152	67.57
10.5	823	83	0.1009	0.8991	61.84
11.5	531	64	0.1205	0.8795	55.60
12.5	323	44	0.1362	0.8638	48.90
13.5	167	26	0.1557	0.8443	42.24
					35.66
Total	44,780	1,606			

Column 2 from Schedule 3, Column 12, Plant Exposed to Retirement.
Column 3 from Schedule 1, Column 12, Retirements for Each Year.
Column 4 = Column 3 Divided by Column 2.
Column 5 = 1.0000 Minus Column 4.
Column 6 = Column 5 Multiplied by Column 6 as of the Preceding Age Interval.

The original survivor curve is plotted from the original life table (column 6, Schedule 4). When the curve terminates at a percent surviving greater than zero, it is called a stub survivor curve. Survivor curves developed from retirement rate studies generally are stub curves.

Smoothing the Original Survivor Curve

The smoothing of the original survivor curve eliminates any irregularities and serves as the basis for the preliminary extrapolation to zero percent surviving of the original stub curve. Even if the original survivor curve is complete from 100% to zero percent, it is desirable to eliminate any irregularities, as there is still an extrapolation for the vintages which have not yet lived to the age at which the curve reaches zero percent. In this study, the smoothing of the original curve with established type curves was used to eliminate irregularities in the original curve.

The Iowa type curves are used in this study to smooth those original stub curves which are expressed as percents surviving at ages in years. Each original survivor curve was compared to the Iowa type curves using visual and mathematical matching in order to determine the better fitting smooth curves. In Figures 6, 7, and 8, the original curve developed in Table 4 is compared with the L, S, and R Iowa type curves which most nearly fit the original survivor curve. In Figure 6, the L1 curve with an average life between 12 and 13 years appears to be the best fit. In Figure 7, the S0 type curve with a 12-year average life appears to be the best fit and appears to be better than the L1 fitting. In Figure 8, the R1 type curve with a 12- year average life appears to be fitting and appears to be better than either the L1 or the S0.

In Figure 9, the three fittings, 12-L1, 12-S0 and 12-R1 are drawn for comparison purposes. It is probable that the 12-R1 Iowa curve would be selected as the most representative of the plotted survivor characteristics of the group.

FIGURE 6. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

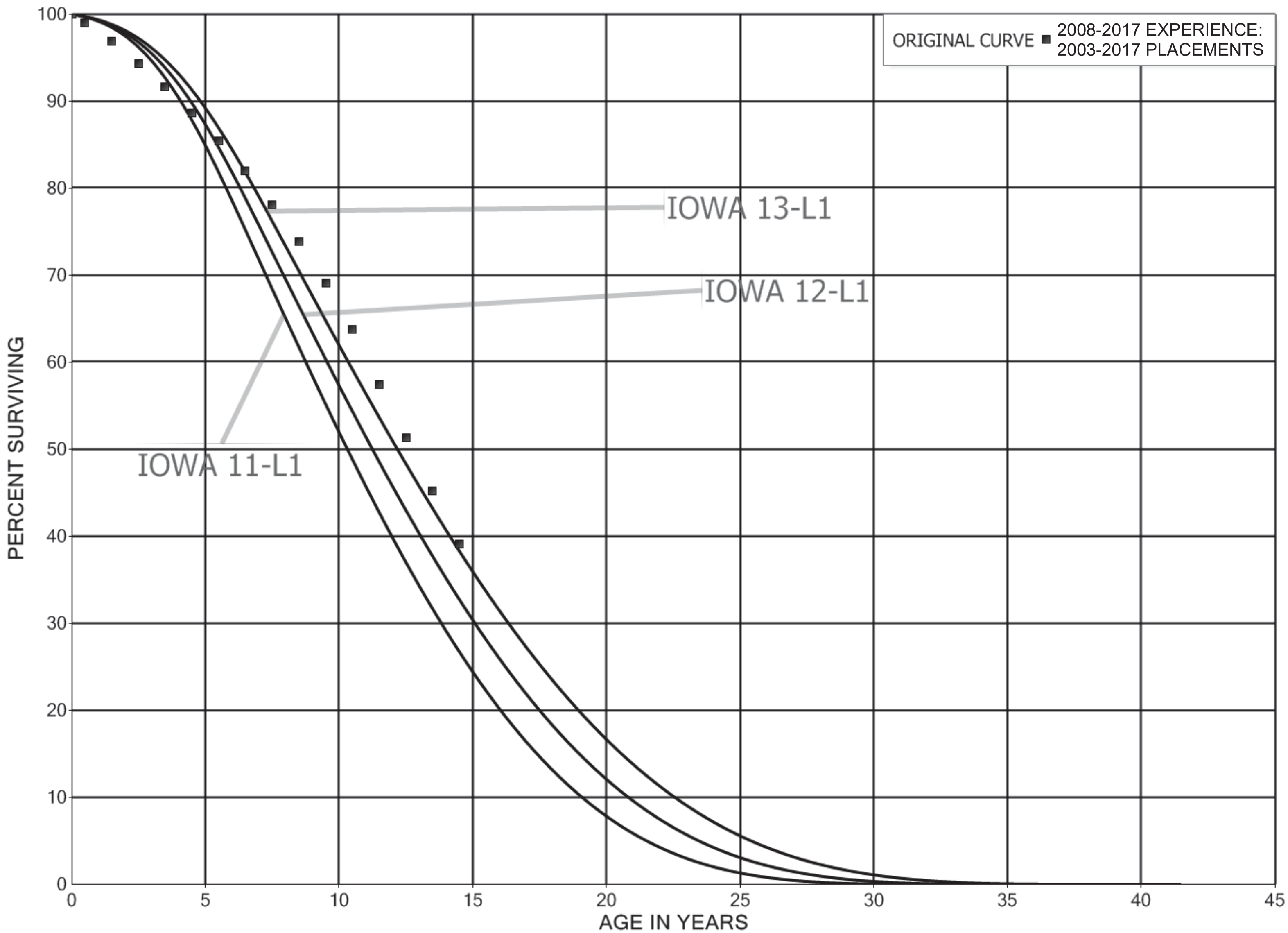


FIGURE 7. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN S0 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

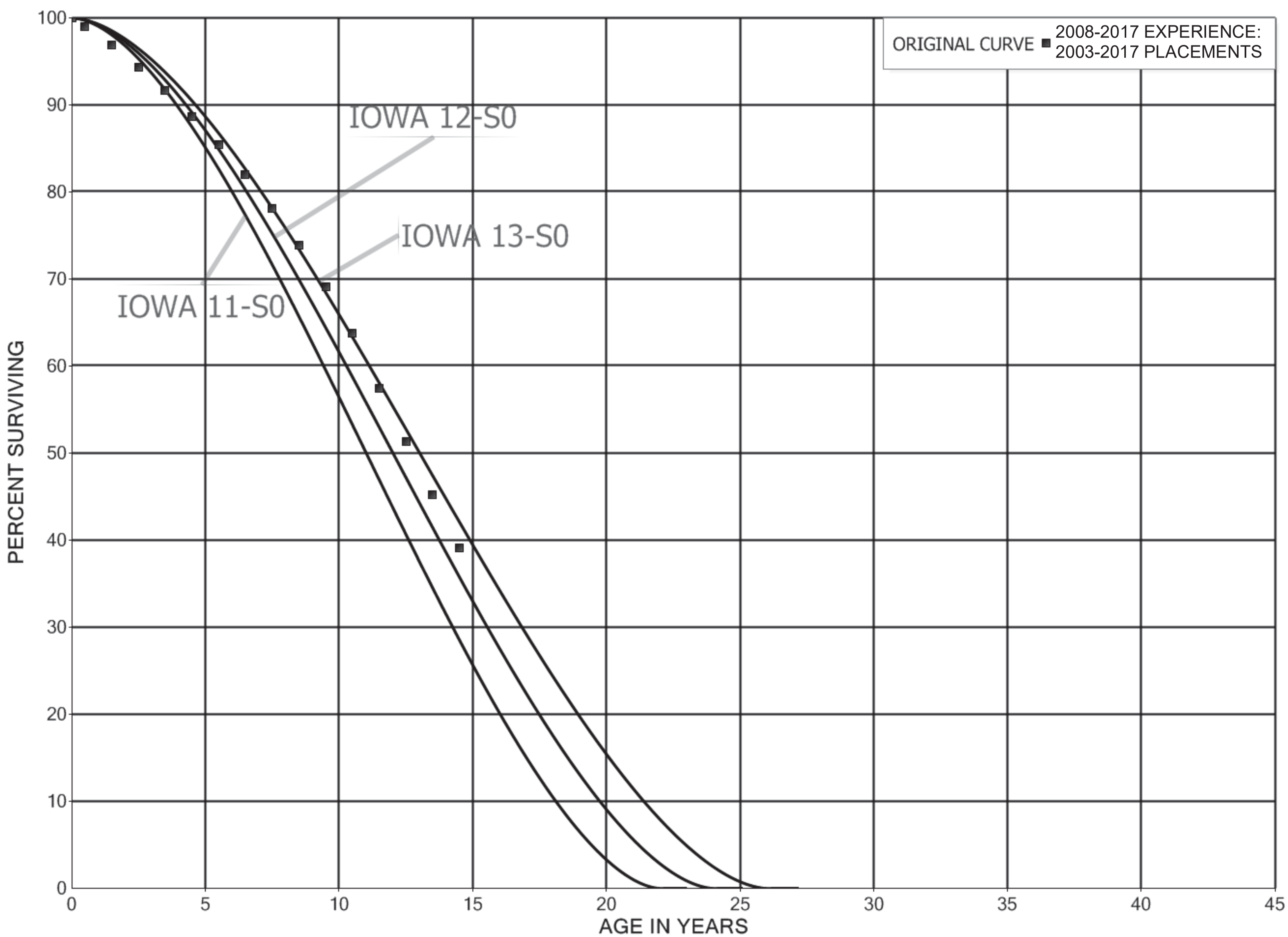


FIGURE 8. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

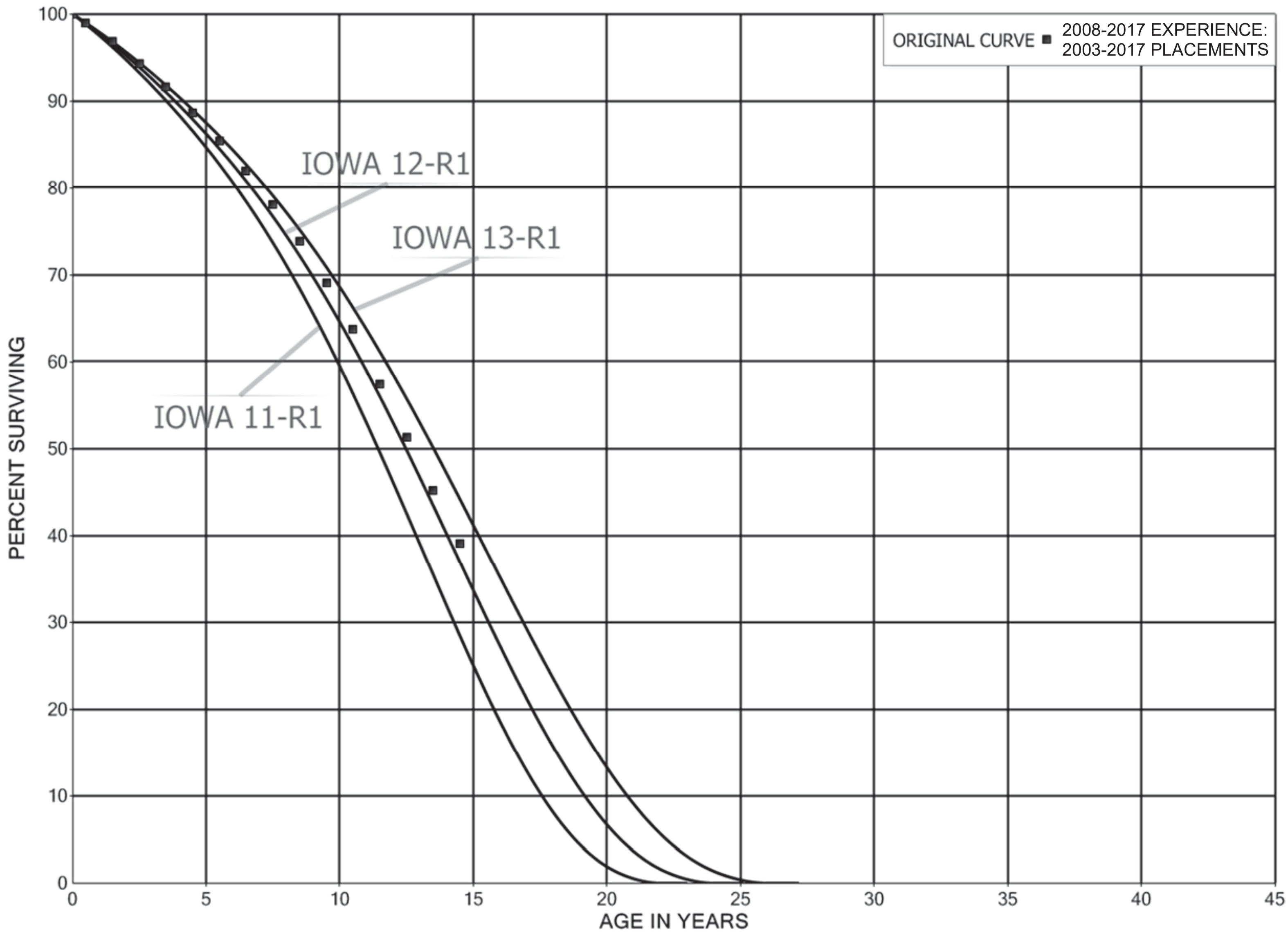
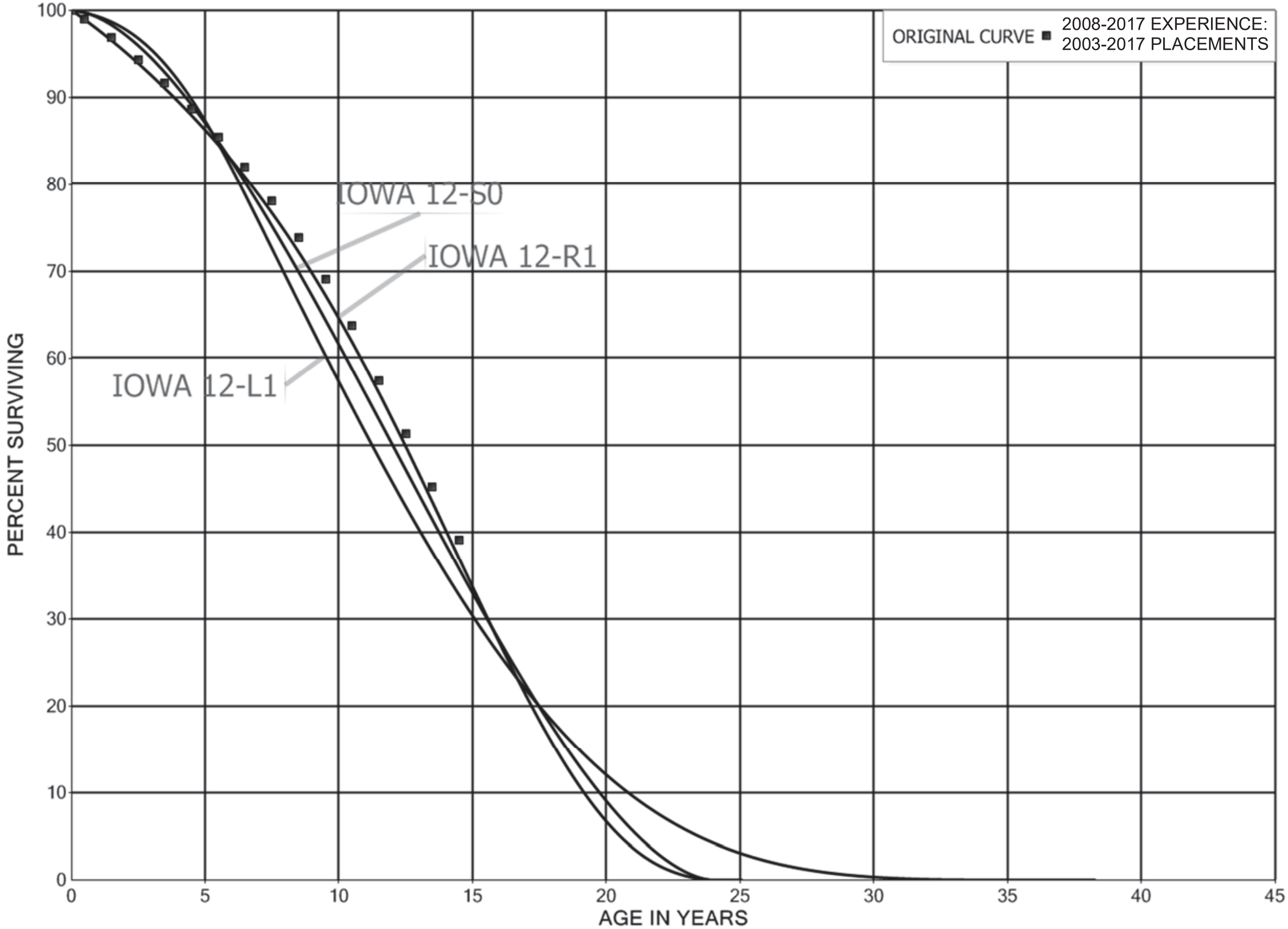


FIGURE 9. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1, S0 AND R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES



PART III. SERVICE LIFE CONSIDERATIONS

PART III. SERVICE LIFE CONSIDERATIONS

SERVICE LIFE ANALYSIS

The service life estimates were based on informed judgment which considered a number of factors. The primary factors were the statistical analyses of data; current Company policies and outlook as determined during conversations with management; and the survivor curve estimates from previous studies of this company and other electric companies.

For many of the plant accounts and subaccounts for which survivor curves were estimated, the statistical analyses using the retirement rate method resulted in reasonable indications of the survivor patterns experienced. These accounts represent 71 percent of depreciable plant. Generally, the information external to the statistics led to no significant departure from the indicated survivor curves for the accounts listed below. The statistical support for the service life estimates is presented in the section beginning on page VII-2.

Account No.	Account Description
ELECTRIC PLANT	
TRANSMISSION PLANT	
352	Structures and Improvements
353	Station Equipment
355	Poles and Fixtures
356	Overhead Conductors and Devices
358	Underground Conductors and Devices
359	Roads and Trails
DISTRIBUTION PLANT	
361	Structures and Improvements
362	Station Equipment
364	Poles, Towers and Fixtures
365.1	Overhead Conductors and Devices – Capacitors
367	Underground Conductors and Devices
368	Line Transformers
369.1	Services – Overhead
370.1	Meters - Electromechanical

	373.1	Street Lighting and Signal Systems – Overhead
	373.2	Street Lighting and Signal Systems – Underground
GENERAL PLANT		
	390	Structures and Improvements

Account, 362, Station Equipment, is used to illustrate the manner in which the study was conducted for the accounts in the preceding list. Aged plant accounting data have been compiled for most accounts for the years 1952 through 2016. These data have been coded according to account or property group, type of transaction, year in which the transaction took place and year in which the utility plant was placed in service. The retirements, other plant transactions and plant additions were analyzed by the retirement rate method.

The survivor curve estimate for 362, Station Equipment is the 45-S0 and is based on the statistical indication for the period 1952 through 2016. Assets in this account include transformers, circuit breakers and relays. Retirements are often due to failure, but also occur due to upgrades required to meet the load. Transformers may remain in service longer than in the past, as system improvements have resulted in reduced loading of transformers. However, circuit breakers and relays may have shorter lives than in the past. For example, the SF6 breakers that are installed today are not expected to last as long as older oil breakers, due to leaks and the inability to repair SF6 breakers. Newer relays are digital equipment, as opposed to the older electromechanical style relays, and are expected to have shorter lives than the older devices. The 45-S0 represents a reasonable fit of the historical data through the representative data points, as shown on page VII-42; is consistent with management outlook for the assets in this account; and is within the typical range of service lives experienced for station equipment.

Similar studies were performed for the remaining plant accounts. Each of the judgments represented a consideration of statistical analyses of aged plant activity, management's outlook for the future, and the typical range of lives and survivor curves used by other electric companies.

The selected amortization periods for other General Plant accounts are described in the section "Calculated Annual and Accrued Amortization."

PART IV. NET SALVAGE CONSIDERATIONS

PART IV. NET SALVAGE CONSIDERATIONS

NET SALVAGE NORMALIZATION

The allowance for net salvage is based on a normalized expense method that has previously been used in New Jersey. The allowance for net salvage by account were based on historical data compiled from 2015 through 2017. Cost of removal and gross salvage by account were averaged over the 3-year period and included by account as the total amount to be recovered. In cases in which removal costs are expected to exceed salvage receipts, a negative net salvage amount is calculated which can be added to the annual depreciation amount to achieve the total annual depreciation amount by account.

Although this method will not achieve the objective of allocating the full service value of the Company's assets over their service lives, the Company has previously agreed to use the historical normalized experience of net salvage. The analyses of historical cost of removal and salvage data are presented by plant account on Table 2 on page VI-6.

PART V. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

PART V. CALCULATION OF ANNUAL AND ACCRUED DEPRECIATION

GROUP DEPRECIATION PROCEDURES

A group procedure for depreciation is appropriate when considering more than a single item of property. Normally the items within a group do not have identical service lives but have lives that are dispersed over a range of time. There are two primary group procedures, namely, average service life and equal life group. In the average service life procedure, the rate of annual depreciation is based on the average life or average remaining life of the group, and this rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life.

Single Unit of Property

The calculation of straight line depreciation for a single unit of property is straightforward. For example, if a \$1,000 unit of property attains an age of four years and has a life expectancy of six years, the annual accrual over the total life is:

$$\frac{\$1,000}{(4 + 6)} = \$100 \text{ per year.}$$

The accrued depreciation is:

$$\$1,000\left(1 - \frac{6}{10}\right) = \$400.$$

Group Depreciation Procedures

A group procedure for depreciation is appropriate when considering more than a single item of property. Normally the items within a group do not have identical service lives, but have lives that are dispersed over a range of time. There are two primary group procedures, namely, average service life and equal life group. In the average service life procedure, the rate of annual depreciation is based on the average life or average remaining life of the group, and this rate is applied to the surviving balances of the group's cost. A characteristic of this procedure is that the cost of plant retired prior to average life is not fully recouped at the time of retirement, whereas the cost of plant retired subsequent to average life is more than fully recouped. Over the entire life cycle, the portion of cost not recouped prior to average life is balanced by the cost recouped subsequent to average life.

In the average service life procedure, the annual accrual rate is computed by the following equation:

$$\textit{Annual Accrual Rate, Percent} = \frac{(\textit{100\% - Net Salvage, Percent})}{\textit{Average Service Life}}.$$

The calculated accrued depreciation for each depreciable property group represents that portion of the depreciable cost of the group which would not be allocated to expense through future depreciation accruals if current forecasts of life characteristics are used as the basis for such accruals. The accrued depreciation calculation consists of applying an appropriate ratio to the surviving original cost of each vintage of each account based upon the attained age and service life. The straight line accrued depreciation ratios are calculated as follows for the average service life procedure:

$$Ratio = 1 - \frac{Average\ Remaining\ Life}{Average\ Service\ Life}$$

CALCULATION OF ANNUAL AND ACCRUED AMORTIZATION

Amortization is the gradual extinguishment of an amount in an account by distributing such amount over a fixed period, over the life of the asset or liability to which it applies, or over the period during which it is anticipated the benefit will be realized. Normally, the distribution of the amount is in equal amounts to each year of the amortization period.

The calculation of annual and accrued amortization requires the selection of an amortization period. The amortization periods used in this report were based on judgment which incorporated a consideration of the period during which the assets will render most of their service, the amortization period and service lives used by other utilities, and the service life estimates previously used for the asset under depreciation accounting.

Amortization accounting is currently used for a number of accounts that represent numerous units of property, but a very small portion of depreciable utility plant in service. No changes to the existing amortization periods are recommended in the study.

PART VI. RESULTS OF STUDY

PART VI. RESULTS OF STUDY

QUALIFICATION OF RESULTS

The calculated annual and accrued depreciation are the principal results of the study. Continued surveillance and periodic revisions are normally required to maintain continued use of appropriate annual depreciation accrual rates. An assumption that accrual rates can remain unchanged over a long period of time implies a disregard for the inherent variability in service lives and net salvage and for the change of the composition of property in service. The annual accrual rates were calculated in accordance with the straight line whole life method of depreciation, using the average service life procedure based on estimates which reflect considerations of current historical evidence and expected future conditions.

The annual depreciation accrual rates are applicable specifically to the electric plant in service as of December 31, 2017. For most plant accounts, the application of such rates to future balances that reflect additions subsequent to December 31, 2017, is reasonable for a period of three to five years.

DESCRIPTION OF DETAILED TABULATIONS

Summary schedules of the results of the study, as applied to the original cost of electric plant in service as of December 31, 2017, are presented on pages VI-4 through VI-6 of this report. The schedules set forth the original cost, the book depreciation reserve, future accruals, the calculated annual depreciation rate and amount, and the composite remaining life related to electric plant. Table 1 sets forth the total annual depreciation accrual rates for electric plant assets as of December 31, 2017. Table 2 sets forth the net salvage normalization amounts by account based on the period 2015 through 2017.

The service life estimates were based on judgment that incorporated statistical analysis of retirement data, discussions with management and consideration of estimates made for other electric utilities. The results of the statistical analysis of service life are presented in the section beginning on page VII-2, within the supporting documents of this report.

For each depreciable group analyzed by the retirement rate method, a chart depicting the original and estimated survivor curves is followed by a tabular presentation of the original life table(s) plotted on the chart. The survivor curves estimated for the depreciable groups are shown as dark smooth curves on the charts. Each smooth survivor curve is denoted by a numeral followed by the curve type designation. The numeral used is the average life derived from the entire curve from 100 percent to zero percent surviving. The titles of the chart indicate the group, the symbol used to plot the points of the original life table, and the experience and placement bands of the life tables which where plotted. The experience band indicates the range of years for which retirements were used to develop the stub survivor curve. The placements indicate, for the related experience band, the range of years of installations which appear in the experience.

The tables of the calculated annual depreciation applicable to depreciable assets as of December 31, 2017 are presented in account sequence starting on page VIII-2 of the supporting documents. The tables indicate the estimated survivor curve for the account and set forth, for each installation year, the original cost, the calculated accrued depreciation, the allocated book reserve, future accruals, the remaining life, and the calculated annual accrual amount.

ROCKLAND ELECTRIC COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES AND ACCRUALS RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2017

	ACCOUNT	SURVIVOR CURVE	ORIGINAL COST AS OF DECEMBER 31, 2017	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(6)/(3)	(8)=(5)/(6)
	ELECTRIC PLANT							
	TRANSMISSION PLANT							
352.00	STRUCTURES AND IMPROVEMENTS	60-R2	1,961,546.03	583,397	1,378,149	31,430	1.60	43.8
353.00	STATION EQUIPMENT	45-S0	14,059,732.11	4,455,848	9,603,884	332,877	2.37	28.9
354.00	TOWERS AND FIXTURES	70-R4	1,184,704.37	541,067	643,637	70,255	5.93	9.2
355.00	POLES AND FIXTURES - WOOD	55-R3	4,474,679.68	1,286,169	3,188,510	79,070	1.77	40.3
355.10	POLES AND FIXTURES - STEEL	55-R3	916,324.19	269,733	646,592	17,748	1.94	36.4
356.00	OVERHEAD CONDUCTORS AND DEVICES	65-R1.5	4,030,023.02	1,370,666	2,659,357	55,532	1.38	47.9
356.10	OVERHEAD CONDUCTORS AND DEVICES - CLEARING	65-R1.5	397,992.41	128,534	269,458	6,626	1.66	40.7
357.00	UNDERGROUND CONDUIT	45-R3	1,116,728.83	397,717	719,012	23,115	2.07	31.1
358.00	UNDERGROUND CONDUCTORS AND DEVICES	35-S3	1,074,720.86	484,072	590,649	29,526	2.75	20.0
359.00	ROADS AND TRAILS	65-R4	96,742.25	48,770	47,972	1,345	1.39	35.7
	TOTAL TRANSMISSION PLANT		**29,313,193.75**	**9,565,974**	**19,747,220**	**647,524**	**2.21**	
	DISTRIBUTION PLANT							
361.00	STRUCTURES AND IMPROVEMENTS	55-R3	4,606,182.94	1,210,078	3,396,105	88,075	1.91	38.6
362.00	STATION EQUIPMENT	45-S0	54,909,124.52	11,304,932	43,604,192	1,262,049	2.30	34.6
364.00	POLES, TOWERS AND FIXTURES	55-R1	50,499,119.96	7,347,015	43,152,105	990,190	1.96	43.6
365.00	OVERHEAD CONDUCTORS AND DEVICES	65-R1.5	57,323,421.73	10,246,036	47,077,386	915,001	1.60	51.5
365.10	OVERHEAD CONDUCTORS AND DEVICES - CAPACITORS	30-R1	1,666,848.38	445,683	1,221,166	56,651	3.40	21.6
366.00	UNDERGROUND CONDUIT	75-R3	18,154,101.40	4,472,579	13,681,522	242,000	1.33	56.5
367.00	UNDERGROUND CONDUCTORS AND DEVICES	60-R4	58,265,607.22	12,131,724	46,133,884	1,021,116	1.75	45.2
367.10	UNDERGROUND CONDUCTORS AND DEVICES - CABLE CURE	60-R4	2,160,120.31	736,789	1,423,331	34,023	1.58	41.8
368.10	LINE TRANSFORMERS - OVERHEAD	45-R0.5	15,241,140.79	3,432,809	11,808,332	376,507	2.47	31.4
368.20	LINE TRANSFORMERS - OVERHEAD INSTALLATIONS	45-R0.5	8,500,430.67	1,442,426	7,058,005	200,739	2.36	35.2
368.30	LINE TRANSFORMERS - UNDERGROUND	45-R0.5	10,843,264.14	2,318,955	8,524,309	259,380	2.39	32.9
368.40	LINE TRANSFORMERS - UNDERGROUND INSTALLATIONS	45-R0.5	3,109,800.40	391,100	2,718,700	71,287	2.29	38.1
369.10	SERVICES - OVERHEAD	65-R3	5,904,236.72	2,345,108	3,559,129	92,644	1.57	38.4
369.20	SERVICES - UNDERGROUND	65-R3	15,179,490.82	5,008,220	10,171,271	220,998	1.46	46.0
370.10	METERS - ELECTROMECHANICAL	25-L0	2,686,188.31	1,272,587	1,413,601	97,039	3.61	14.6
370.11	METERS - SOLID STATE	20-S2.5	2,173,490.39	540,524	1,632,967	140,215	6.45	11.6
370.20	METER INSTALLATIONS - ELECTROMECHANICAL	25-L0	1,335,336.20	654,627	680,709	48,100	3.60	14.2
370.21	METER INSTALLATIONS - SOLID STATE	20-S2.5	2,996,229.30	640,173	2,356,056	181,733	6.07	13.0
371.00	INSTALLATIONS ON CUSTOMERS' PREMISES	35-R0.5	582,740.41	207,593	375,148	14,710	2.52	25.5
373.10	STREET LIGHTING AND SIGNAL SYSTEMS - OVERHEAD	40-R0.5	3,548,678.94	827,773	2,720,906	102,121	2.88	26.6
373.20	STREET LIGHTING AND SIGNAL SYSTEMS - UNDERGROUND	40-R0.5	1,396,869.83	349,427	1,047,442	39,456	2.82	26.5
	TOTAL DISTRIBUTION PLANT		**321,082,423.38**	**67,326,157**	**253,756,266**	**6,454,034**	**2.01**	

ROCKLAND ELECTRIC COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES AND ACCRUALS RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2017

	ACCOUNT	SURVIVOR CURVE	ORIGINAL COST AS OF DECEMBER 31, 2017	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(6)/(3)	(8)=(5)/(6)
	GENERAL PLANT							
390.00	STRUCTURES AND IMPROVEMENTS	45-S0	689,261.10	221,932	467,329	15,477	2.25	30.2
	TOTAL GENERAL PLANT		**689,261.10**	**221,932**	**467,329**	**15,477**	**2.25**	
	TOTAL DEPRECIABLE ELECTRIC PLANT		**351,084,878.23**	**77,114,062**	**273,970,815**	**7,117,035**	**2.03**	
	NONDEPRECIABLE AND ACCOUNTS NOT STUDIED							
301.00	ORGANIZATION		5,636.12					
302.00	FRANCHISES AND CONSENTS		441.59					
350.00	LAND AND LAND RIGHTS - EASEMENTS		1,440,974.69					
350.10	LAND AND LAND RIGHTS - FEE		387,670.89					
360.00	LAND AND LAND RIGHTS - EASEMENTS		180,609.34					
360.09	LAND AND LAND RIGHTS - EASEMENT (FUTURE USE)		41,660.00					
360.10	LAND AND LAND RIGHTS - FEE		2,713,001.98					
360.19	LAND AND LAND RIGHTS - FEE (FUTURE USE)		167,049.29					
389.10	LAND AND LAND RIGHTS - FEE		154,414.77					
390.14	STRUCTURES AND IMPROVEMENTS - LETHBRIDGE PLAZA		235,554.08	142,523				
391.10	OFFICE FURNITURE AND EQUIPMENT - FURNITURE		3,614.57	(13,969)				
391.20	OFFICE FURNITURE AND EQUIPMENT - BUSINESS MACHINES			(6,593)				
391.70	OFFICE FURNITURE AND EQUIPMENT - EDP EQUIPMENT		121,950.51	103,316				
392.40	TRAILERS AND TRUCK MOUNTED EQUIPMENT		(30.55)					
393.00	STORES EQUIPMENT		2,025.54	1,202				
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT		450,563.51	59,219				
394.20	GARAGE EQUIPMENT		81,387.25	58,222				
395.00	LABORATORY EQUIPMENT		224,222.33	47,773				
396.00	POWER OPERATED EQUIPMENT			(41,335)				
397.00	COMMUNICATION EQUIPMENT		7,090,392.45	2,499,301				
397.10	COMMUNICATION EQUIPMENT - TELEPHONE SYSTEM COMPUTER		40,248.05	17,827				
397.20	COMMUNICATION EQUIPMENT - TELEPHONE SYSTEM EQUIPMENT		27,170.98	(1,665)				
398.00	MISCELLANEOUS EQUIPMENT		281,187.59	24,872				
399.00	UNALLOCATED RESERVE			5,877,129				
	TOTAL NONDEPRECIABLE AND ACCOUNTS NOT STUDIED		**13,649,744.98**	**8,767,822**				
	TOTAL ELECTRIC PLANT		**364,734,623.21**	**85,881,884**				

NOTES:

ADDITIONS TO NEW METERS ACCOUNTS SHOULD USE THE FOLLOWING SURVIVOR CURVES AND ANNUAL ACCRUAL RATES:

ACCOUNT	SURVIVOR CURVE	ACCRUAL RATE
ACCOUNT 370.12 METERS - AMI METERS	20-S2.5	5.00%
ACCOUNT 370.15 METERS - UNRECOVERED ELECTROMECHANICAL PURCHASES	25-L0	4.00%
ACCOUNT 370.16 METERS - UNRECOVERED SOLID STATE PURCHASES	20-S2.5	5.00%
ACCOUNT 370.12 METER INSTALLATIONS - AMI METERS	20-S2.5	5.00%
ACCOUNT 370.15 METER INSTALLATIONS - UNRECOVERED ELECTROMECHANICAL PURCHASES	25-L0	4.00%
ACCOUNT 370.16 METER INSTALLATIONS - UNRECOVERED SOLID STATE PURCHASES	20-S2.5	5.00%

ROCKLAND ELECTRIC COMPANY

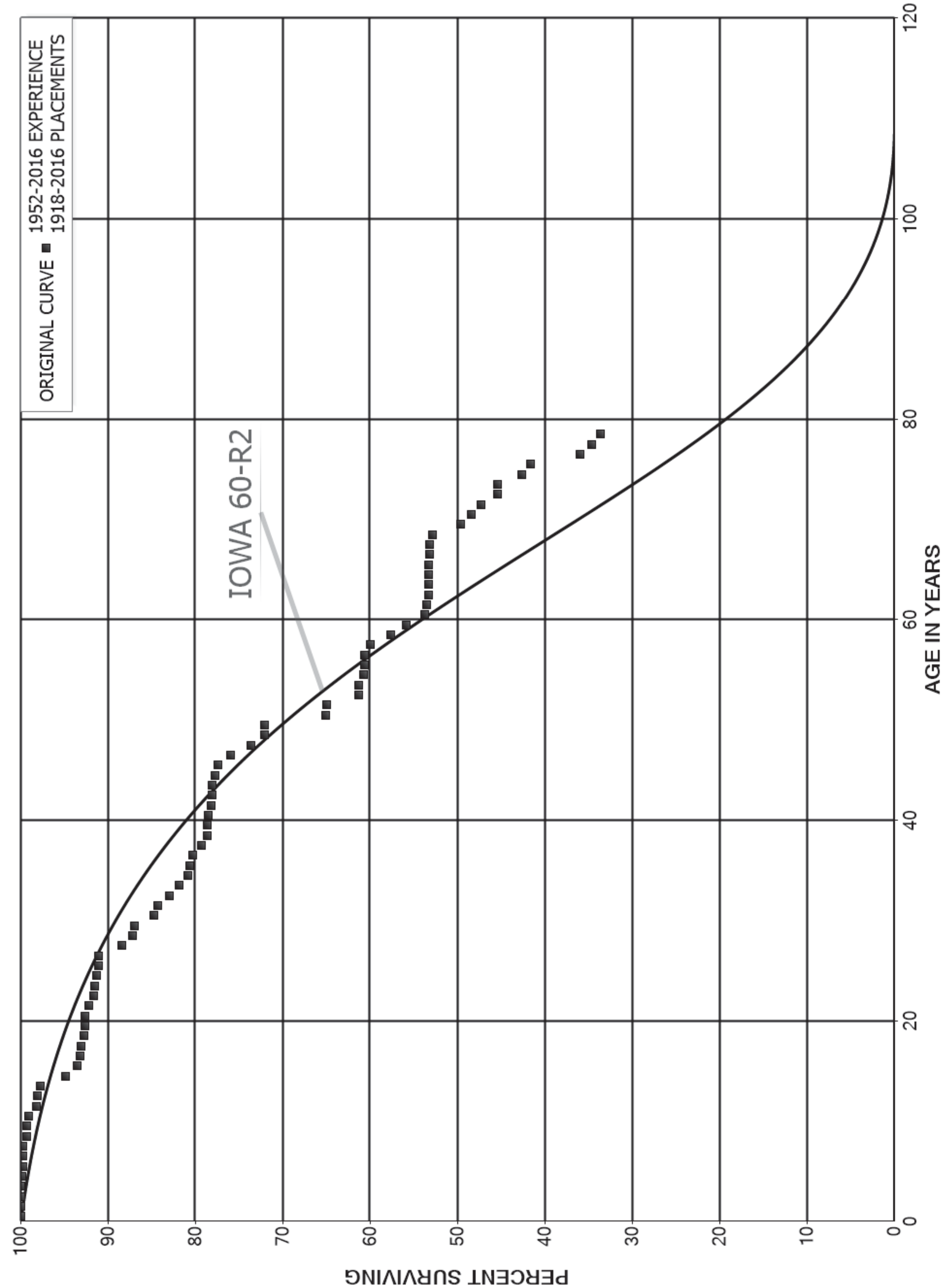
TABLE 2. CALCULATION OF NET SALVAGE NORMALIZATION

EXPERIENCED COST OF REMOVAL AND GROSS SALVAGE FOR THE PERIOD 2015 THROUGH 2017

	2015		2016		2017			NET
ACCOUNT	COST OF REMOVAL	GROSS SALVAGE	COST OF REMOVAL	GROSS SALVAGE	COST OF REMOVAL	GROSS SALVAGE	NET SALVAGE	SALVAGE NORMALIZATION
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)=-(8)/3
353.00	0	0	0	0	101,108	0	(101,108)	33,703
354.00	0	0	0	0	418,154	0	(418,154)	139,385
355.00	345	0	0	0	46,357	0	(46,703)	15,568
356.00	190	0	0	0	0	0	(190)	63
359.00	0	0	0	0	92,862	0	(92,862)	30,954
361.00	0	0	0	0	216,805	0	(216,805)	72,268
362.00	60,387	0	40,420	0	1,046,050	13,089	(1,133,768)	377,923
364.00	348,336	0	355,685	0	252,284	0	(956,306)	318,769
365.00	391,686	0	319,441	0	352,063	0	(1,063,190)	354,397
365.10	7,296	0	3,973	0	8,099	0	(19,368)	6,456
366.00	15,256	0	5,946	0	6,583	633	(27,152)	9,051
367.00	29,106	0	34,377	0	62,196	0	(125,679)	41,893
368.10	49,710	0	79,691	0	61,459	0	(190,860)	63,620
368.20	33,607	0	26,694	0	31,645	0	(91,946)	30,649
368.30	10,102	0	1,316	0	5,065	0	(16,482)	5,494
368.40	3,609	0	6,080	0	21,550	0	(31,239)	10,413
369.10	91,124	0	97,506	0	114,998	0	(303,628)	101,209
369.20	22,287	0	22,923	0	21,037	0	(66,247)	22,082
373.10	61,107	0	43,955	0	62,995	0	(168,058)	56,019
373.20	8,648	0	10,047	0	8,908	0	(27,603)	9,201
390.00	71,323	0	0	0	0	0	(71,323)	23,774
	1,204,120	**0**	**1,048,053**	**0**	**2,930,219**	**13,723**	**(5,168,670)**	**1,722,891**

PART VII. SERVICE LIFE STATISTICS

ROCKLAND ELECTRIC COMPANY
ACCOUNT 352.00 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



ROCKLAND ELECTRIC COMPANY

ACCOUNT 352.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1918-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	13,360,764		0.0000	1.0000	100.00
0.5	12,714,096		0.0000	1.0000	100.00
1.5	12,160,831	1,511	0.0001	0.9999	100.00
2.5	12,178,899		0.0000	1.0000	99.99
3.5	12,178,610	18,544	0.0015	0.9985	99.99
4.5	12,021,275	7,420	0.0006	0.9994	99.84
5.5	10,554,718	5,072	0.0005	0.9995	99.77
6.5	10,190,484	4,501	0.0004	0.9996	99.73
7.5	10,145,739	40,209	0.0040	0.9960	99.68
8.5	9,700,528	3,866	0.0004	0.9996	99.29
9.5	9,508,055	19,518	0.0021	0.9979	99.25
10.5	9,365,699	78,625	0.0084	0.9916	99.04
11.5	8,446,404	16,039	0.0019	0.9981	98.21
12.5	7,207,375	20,339	0.0028	0.9972	98.03
13.5	7,160,149	213,996	0.0299	0.9701	97.75
14.5	6,020,190	81,750	0.0136	0.9864	94.83
15.5	5,744,517	24,203	0.0042	0.9958	93.54
16.5	5,515,311	3,287	0.0006	0.9994	93.15
17.5	5,181,360	23,299	0.0045	0.9955	93.09
18.5	5,153,548	1,631	0.0003	0.9997	92.67
19.5	5,140,621	2,920	0.0006	0.9994	92.64
20.5	5,141,494	25,569	0.0050	0.9950	92.59
21.5	4,953,252	26,104	0.0053	0.9947	92.13
22.5	4,928,675	4,753	0.0010	0.9990	91.64
23.5	5,010,415	13,383	0.0027	0.9973	91.56
24.5	4,943,555	15,756	0.0032	0.9968	91.31
25.5	4,919,937	71	0.0000	1.0000	91.02
26.5	4,811,794	136,801	0.0284	0.9716	91.02
27.5	4,229,287	62,085	0.0147	0.9853	88.43
28.5	4,167,678	8,758	0.0021	0.9979	87.13
29.5	4,135,660	104,925	0.0254	0.9746	86.95
30.5	4,030,735	23,514	0.0058	0.9942	84.74
31.5	3,914,635	60,577	0.0155	0.9845	84.25
32.5	3,849,006	50,828	0.0132	0.9868	82.95
33.5	3,798,191	49,477	0.0130	0.9870	81.85
34.5	3,332,633	6,697	0.0020	0.9980	80.78
35.5	3,014,749	14,616	0.0048	0.9952	80.62
36.5	2,933,257	34,049	0.0116	0.9884	80.23
37.5	2,897,402	24,544	0.0085	0.9915	79.30
38.5	2,865,498	1,312	0.0005	0.9995	78.63

ROCKLAND ELECTRIC COMPANY

ACCOUNT 352.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1918-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	2,746,980	2,797	0.0010	0.9990	78.59
40.5	2,482,706	11,587	0.0047	0.9953	78.51
41.5	2,262,674	2,943	0.0013	0.9987	78.15
42.5	2,012,861	146	0.0001	0.9999	78.04
43.5	1,986,288	6,842	0.0034	0.9966	78.04
44.5	1,391,896	6,156	0.0044	0.9956	77.77
45.5	577,714	10,938	0.0189	0.9811	77.42
46.5	502,142	15,138	0.0301	0.9699	75.96
47.5	479,265	10,366	0.0216	0.9784	73.67
48.5	381,408		0.0000	1.0000	72.08
49.5	381,408	37,094	0.0973	0.9027	72.08
50.5	339,152	481	0.0014	0.9986	65.07
51.5	331,324	18,939	0.0572	0.9428	64.97
52.5	288,877		0.0000	1.0000	61.26
53.5	288,877	2,288	0.0079	0.9921	61.26
54.5	284,652	927	0.0033	0.9967	60.77
55.5	256,718		0.0000	1.0000	60.58
56.5	234,396	2,486	0.0106	0.9894	60.58
57.5	188,548	7,413	0.0393	0.9607	59.93
58.5	181,071	5,459	0.0301	0.9699	57.58
59.5	175,473	6,781	0.0386	0.9614	55.84
60.5	166,881	636	0.0038	0.9962	53.68
61.5	163,549	620	0.0038	0.9962	53.48
62.5	138,701	88	0.0006	0.9994	53.28
63.5	138,613		0.0000	1.0000	53.24
64.5	138,123		0.0000	1.0000	53.24
65.5	138,123	38	0.0003	0.9997	53.24
66.5	138,085	68	0.0005	0.9995	53.23
67.5	136,066	1,001	0.0074	0.9926	53.20
68.5	118,344	7,166	0.0606	0.9394	52.81
69.5	111,178	2,625	0.0236	0.9764	49.61
70.5	108,553	2,710	0.0250	0.9750	48.44
71.5	105,843	4,139	0.0391	0.9609	47.23
72.5	101,704		0.0000	1.0000	45.39
73.5	101,704	6,285	0.0618	0.9382	45.39
74.5	95,216	2,213	0.0232	0.9768	42.58
75.5	92,523	12,661	0.1368	0.8632	41.59
76.5	79,862	2,751	0.0344	0.9656	35.90
77.5	77,111	2,227	0.0289	0.9711	34.66
78.5	74,884		0.0000	1.0000	33.66

ROCKLAND ELECTRIC COMPANY

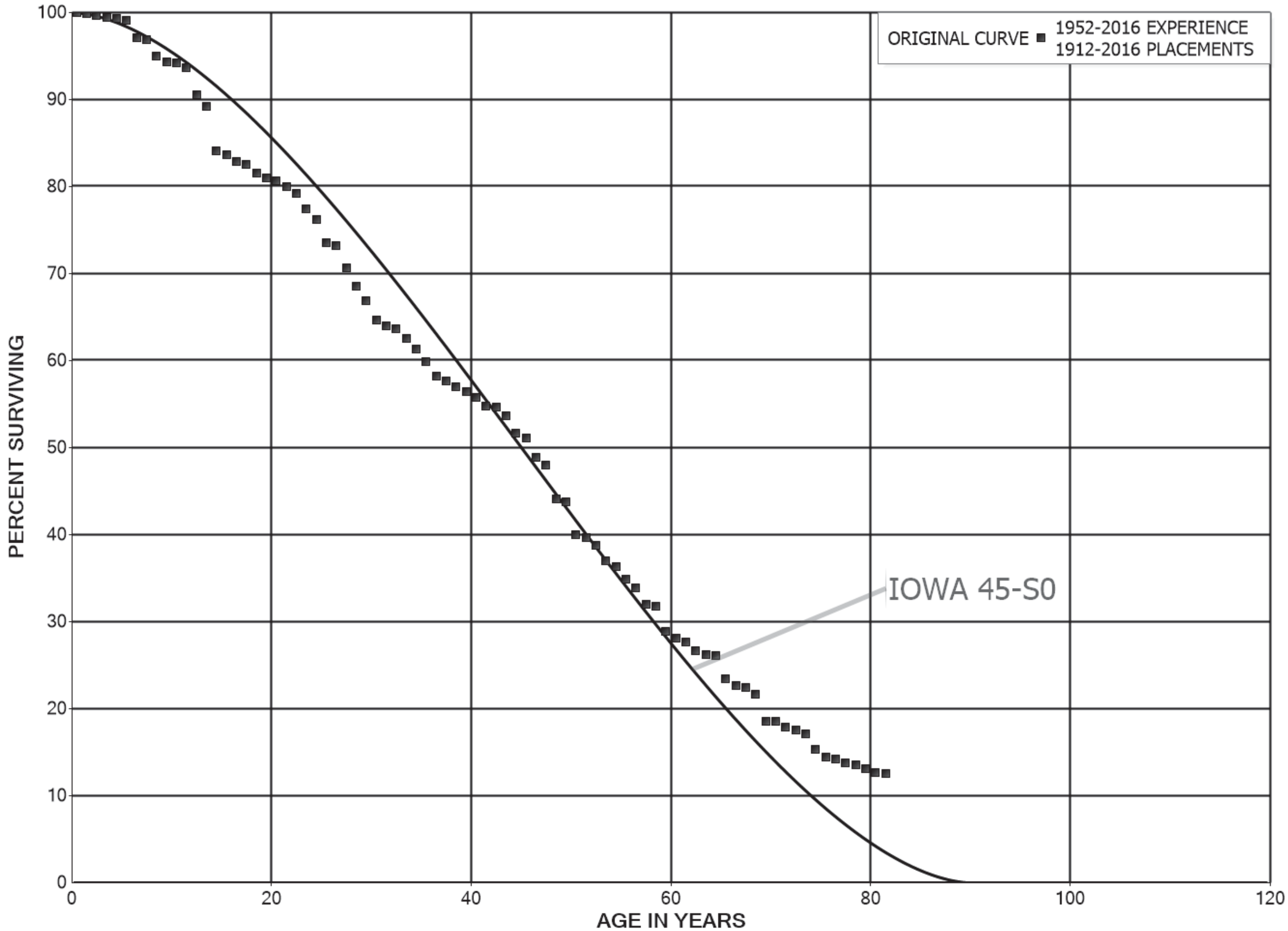
ACCOUNT 352.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1918-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	74,884		0.0000	1.0000	33.66
80.5	74,884	13	0.0002	0.9998	33.66
81.5	74,871		0.0000	1.0000	33.66
82.5	74,871		0.0000	1.0000	33.66
83.5	74,871		0.0000	1.0000	33.66
84.5	74,871		0.0000	1.0000	33.66
85.5	74,871		0.0000	1.0000	33.66
86.5	73,703		0.0000	1.0000	33.66
87.5	72,320		0.0000	1.0000	33.66
88.5	291		0.0000	1.0000	33.66
89.5					33.66

ROCKLAND ELECTRIC COMPANY
ACCOUNT 353.00 STATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



ROCKLAND ELECTRIC COMPANY

ACCOUNT 353.00 STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1912-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	139,848,172		0.0000	1.0000	100.00
0.5	131,068,358	270,623	0.0021	0.9979	100.00
1.5	130,602,261	227,382	0.0017	0.9983	99.79
2.5	128,968,949	241,940	0.0019	0.9981	99.62
3.5	125,182,086	238,944	0.0019	0.9981	99.43
4.5	122,866,153	262,110	0.0021	0.9979	99.24
5.5	102,120,830	2,000,977	0.0196	0.9804	99.03
6.5	99,614,811	226,245	0.0023	0.9977	97.09
7.5	97,207,773	1,983,037	0.0204	0.9796	96.87
8.5	92,320,589	540,147	0.0059	0.9941	94.89
9.5	89,590,208	183,298	0.0020	0.9980	94.34
10.5	87,252,381	501,259	0.0057	0.9943	94.15
11.5	84,898,831	2,781,595	0.0328	0.9672	93.61
12.5	79,275,163	1,213,119	0.0153	0.9847	90.54
13.5	77,086,834	4,357,647	0.0565	0.9435	89.15
14.5	69,305,769	429,073	0.0062	0.9938	84.11
15.5	54,769,607	476,614	0.0087	0.9913	83.59
16.5	51,529,962	247,519	0.0048	0.9952	82.86
17.5	50,442,682	560,090	0.0111	0.9889	82.47
18.5	49,633,965	394,875	0.0080	0.9920	81.55
19.5	49,129,192	165,556	0.0034	0.9966	80.90
20.5	48,985,215	435,585	0.0089	0.9911	80.63
21.5	48,233,994	418,586	0.0087	0.9913	79.91
22.5	47,606,954	1,070,480	0.0225	0.9775	79.22
23.5	46,268,212	748,084	0.0162	0.9838	77.44
24.5	44,950,556	1,587,986	0.0353	0.9647	76.19
25.5	40,514,627	173,835	0.0043	0.9957	73.49
26.5	39,855,379	1,388,744	0.0348	0.9652	73.18
27.5	36,595,044	1,114,810	0.0305	0.9695	70.63
28.5	35,440,521	833,213	0.0235	0.9765	68.48
29.5	34,495,779	1,141,442	0.0331	0.9669	66.87
30.5	33,059,517	350,141	0.0106	0.9894	64.66
31.5	32,139,558	203,989	0.0063	0.9937	63.97
32.5	31,861,037	511,258	0.0160	0.9840	63.56
33.5	31,246,152	617,753	0.0198	0.9802	62.54
34.5	26,388,664	624,604	0.0237	0.9763	61.31
35.5	23,310,630	661,784	0.0284	0.9716	59.86
36.5	21,724,650	201,380	0.0093	0.9907	58.16
37.5	20,969,049	256,898	0.0123	0.9877	57.62
38.5	20,656,227	190,177	0.0092	0.9908	56.91

ROCKLAND ELECTRIC COMPANY

ACCOUNT 353.00 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1912-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	20,094,046	228,268	0.0114	0.9886	56.39
40.5	18,259,107	328,669	0.0180	0.9820	55.75
41.5	16,714,264	33,973	0.0020	0.9980	54.74
42.5	15,433,056	291,420	0.0189	0.9811	54.63
43.5	14,169,543	522,915	0.0369	0.9631	53.60
44.5	11,151,726	130,855	0.0117	0.9883	51.62
45.5	7,596,030	332,656	0.0438	0.9562	51.02
46.5	5,465,125	91,086	0.0167	0.9833	48.78
47.5	4,954,248	408,804	0.0825	0.9175	47.97
48.5	4,113,053	24,023	0.0058	0.9942	44.01
49.5	4,058,339	358,241	0.0883	0.9117	43.75
50.5	3,548,304	24,130	0.0068	0.9932	39.89
51.5	3,057,710	65,205	0.0213	0.9787	39.62
52.5	2,240,661	102,870	0.0459	0.9541	38.78
53.5	2,137,148	41,732	0.0195	0.9805	37.00
54.5	2,085,533	83,537	0.0401	0.9599	36.27
55.5	1,756,477	49,990	0.0285	0.9715	34.82
56.5	1,705,508	97,278	0.0570	0.9430	33.83
57.5	1,255,613	7,878	0.0063	0.9937	31.90
58.5	1,233,366	110,748	0.0898	0.9102	31.70
59.5	990,784	27,716	0.0280	0.9720	28.85
60.5	915,751	14,076	0.0154	0.9846	28.05
61.5	891,465	33,487	0.0376	0.9624	27.62
62.5	792,719	10,921	0.0138	0.9862	26.58
63.5	781,798	3,095	0.0040	0.9960	26.21
64.5	436,772	45,548	0.1043	0.8957	26.11
65.5	388,985	13,406	0.0345	0.9655	23.39
66.5	367,539	3,015	0.0082	0.9918	22.58
67.5	301,493	11,155	0.0370	0.9630	22.39
68.5	278,264	39,277	0.1412	0.8588	21.57
69.5	237,942	775	0.0033	0.9967	18.52
70.5	237,167	7,928	0.0334	0.9666	18.46
71.5	226,809	4,829	0.0213	0.9787	17.84
72.5	218,334	4,927	0.0226	0.9774	17.46
73.5	213,374	22,935	0.1075	0.8925	17.07
74.5	189,256	10,451	0.0552	0.9448	15.24
75.5	178,788	2,171	0.0121	0.9879	14.39
76.5	176,513	6,612	0.0375	0.9625	14.22
77.5	165,580	2,062	0.0125	0.9875	13.69
78.5	163,279	5,146	0.0315	0.9685	13.52

ROCKLAND ELECTRIC COMPANY

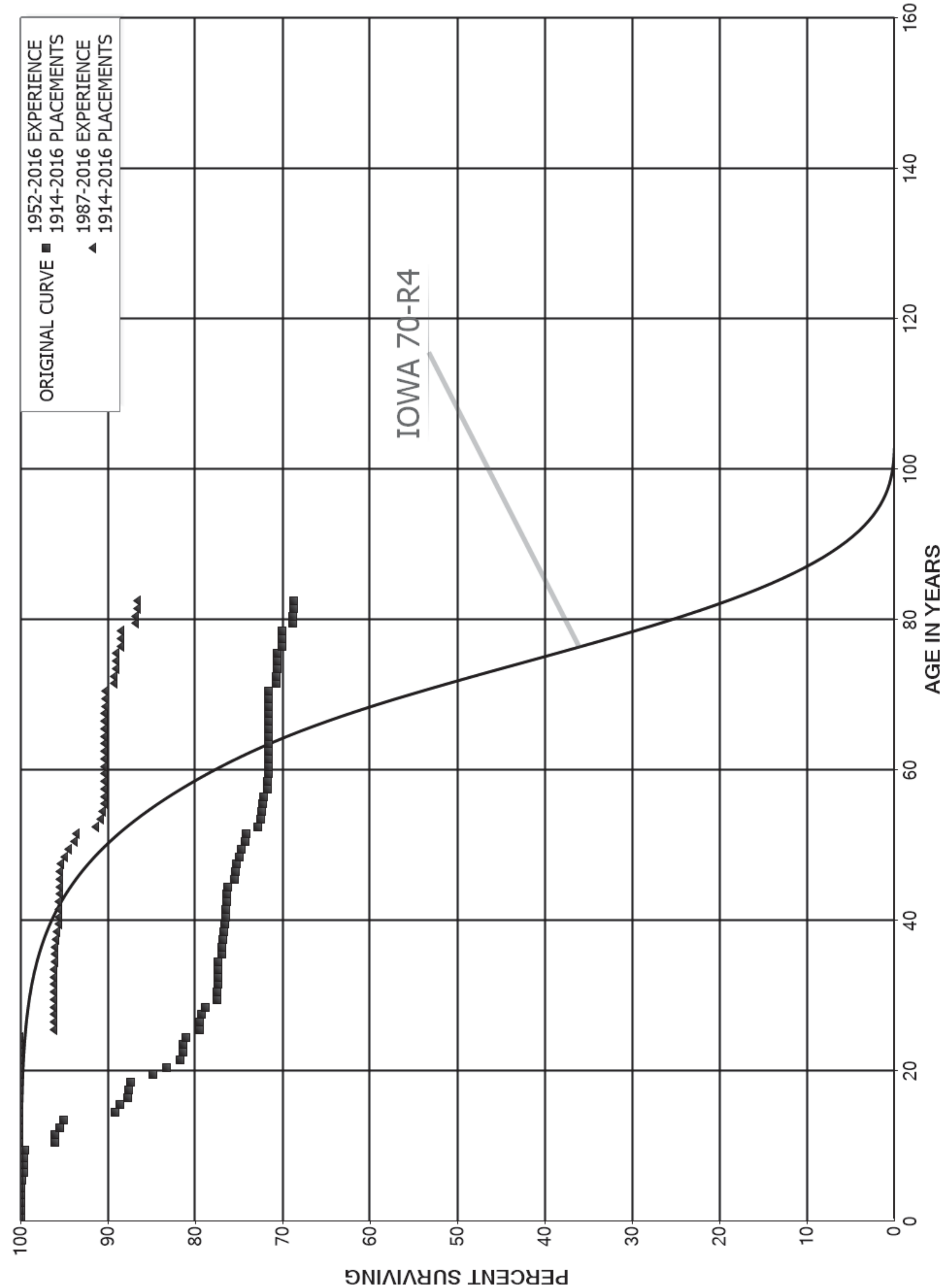
ACCOUNT 353.00 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1912-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	157,141	5,977	0.0380	0.9620	13.09
80.5	150,877	826	0.0055	0.9945	12.59
81.5	150,051		0.0000	1.0000	12.52
82.5	150,051		0.0000	1.0000	12.52
83.5	150,051		0.0000	1.0000	12.52
84.5	150,051		0.0000	1.0000	12.52
85.5	130,224		0.0000	1.0000	12.52
86.5	65,390		0.0000	1.0000	12.52
87.5	64,961	18	0.0003	0.9997	12.52
88.5	30,515	18	0.0006	0.9994	12.52
89.5	6,851		0.0000	1.0000	12.51
90.5	6,851		0.0000	1.0000	12.51
91.5	683		0.0000	1.0000	12.51
92.5					12.51

ROCKLAND ELECTRIC COMPANY
ACCOUNT 354.00 TOWERS AND FIXTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES



ROCKLAND ELECTRIC COMPANY

ACCOUNT 354.00 TOWERS AND FIXTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1914-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	10,845,951		0.0000	1.0000	100.00
0.5	10,557,568	1,572	0.0001	0.9999	100.00
1.5	10,551,958	251	0.0000	1.0000	99.99
2.5	6,377,603	53	0.0000	1.0000	99.98
3.5	6,377,550	1,274	0.0002	0.9998	99.98
4.5	6,376,276	7,004	0.0011	0.9989	99.96
5.5	6,371,172	14,846	0.0023	0.9977	99.85
6.5	6,225,181		0.0000	1.0000	99.62
7.5	6,225,365	3,444	0.0006	0.9994	99.62
8.5	6,221,921	5,301	0.0009	0.9991	99.56
9.5	6,216,620	214,765	0.0345	0.9655	99.48
10.5	6,001,978	812	0.0001	0.9999	96.04
11.5	6,034,602	36,155	0.0060	0.9940	96.03
12.5	5,998,496	24,253	0.0040	0.9960	95.45
13.5	5,974,243	370,859	0.0621	0.9379	95.07
14.5	5,603,384	31,920	0.0057	0.9943	89.17
15.5	5,571,557	59,569	0.0107	0.9893	88.66
16.5	5,512,038	7,083	0.0013	0.9987	87.71
17.5	6,086,510	11,004	0.0018	0.9982	87.60
18.5	6,075,506	184,346	0.0303	0.9697	87.44
19.5	5,891,160	102,555	0.0174	0.9826	84.79
20.5	5,749,018	107,846	0.0188	0.9812	83.31
21.5	5,936,917	28,966	0.0049	0.9951	81.75
22.5	6,122,817	178	0.0000	1.0000	81.35
23.5	6,174,269	25,376	0.0041	0.9959	81.35
24.5	5,649,628	104,934	0.0186	0.9814	81.01
25.5	5,544,694	19	0.0000	1.0000	79.51
26.5	5,603,377	14,333	0.0026	0.9974	79.51
27.5	5,594,313	33,148	0.0059	0.9941	79.30
28.5	5,561,165	95,297	0.0171	0.9829	78.83
29.5	5,475,106	1,161	0.0002	0.9998	77.48
30.5	5,473,945	1,359	0.0002	0.9998	77.47
31.5	5,472,586	13	0.0000	1.0000	77.45
32.5	5,472,573	16	0.0000	1.0000	77.45
33.5	5,472,557	2,892	0.0005	0.9995	77.45
34.5	5,470,458	33,776	0.0062	0.9938	77.41
35.5	5,437,061	1,756	0.0003	0.9997	76.93
36.5	5,400,576	8,304	0.0015	0.9985	76.90
37.5	5,431,710	5,055	0.0009	0.9991	76.79
38.5	5,397,600	10,392	0.0019	0.9981	76.71

ROCKLAND ELECTRIC COMPANY

ACCOUNT 354.00 TOWERS AND FIXTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1914-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	5,387,208	529	0.0001	0.9999	76.57
40.5	5,386,679	214	0.0000	1.0000	76.56
41.5	5,386,465	11,893	0.0022	0.9978	76.56
42.5	4,861,748	2,959	0.0006	0.9994	76.39
43.5	4,847,669	3,415	0.0007	0.9993	76.34
44.5	4,224,048	41,594	0.0098	0.9902	76.29
45.5	3,703,476	7,636	0.0021	0.9979	75.54
46.5	3,695,840	6,738	0.0018	0.9982	75.38
47.5	3,373,138	10,993	0.0033	0.9967	75.24
48.5	3,272,087	13,744	0.0042	0.9958	75.00
49.5	3,126,108	16,029	0.0051	0.9949	74.68
50.5	2,832,452	5,382	0.0019	0.9981	74.30
51.5	2,827,070	48,879	0.0173	0.9827	74.16
52.5	2,778,191	13,000	0.0047	0.9953	72.88
53.5	2,764,598	6,230	0.0023	0.9977	72.53
54.5	2,739,104	4,419	0.0016	0.9984	72.37
55.5	2,669,526	1,597	0.0006	0.9994	72.25
56.5	2,667,929	17,690	0.0066	0.9934	72.21
57.5	2,579,306	1,706	0.0007	0.9993	71.73
58.5	2,441,308	887	0.0004	0.9996	71.68
59.5	2,440,421	40	0.0000	1.0000	71.66
60.5	1,764,098	371	0.0002	0.9998	71.66
61.5	1,762,643		0.0000	1.0000	71.64
62.5	1,746,422		0.0000	1.0000	71.64
63.5	1,245,753	1	0.0000	1.0000	71.64
64.5	1,159,482	379	0.0003	0.9997	71.64
65.5	1,159,103	273	0.0002	0.9998	71.62
66.5	1,157,487		0.0000	1.0000	71.60
67.5	1,157,487	403	0.0003	0.9997	71.60
68.5	1,157,084		0.0000	1.0000	71.58
69.5	1,157,084	128	0.0001	0.9999	71.58
70.5	1,156,005	13,168	0.0114	0.9886	71.57
71.5	1,142,837		0.0000	1.0000	70.75
72.5	1,142,837	2,771	0.0024	0.9976	70.75
73.5	1,140,066		0.0000	1.0000	70.58
74.5	1,140,066		0.0000	1.0000	70.58
75.5	1,140,066	7,718	0.0068	0.9932	70.58
76.5	1,132,348		0.0000	1.0000	70.10
77.5	1,132,336		0.0000	1.0000	70.10
78.5	1,132,336	21,195	0.0187	0.9813	70.10

ROCKLAND ELECTRIC COMPANY

ACCOUNT 354.00 TOWERS AND FIXTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1914-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	1,111,141		0.0000	1.0000	68.79
80.5	1,111,141	1,703	0.0015	0.9985	68.79
81.5	1,109,439		0.0000	1.0000	68.69
82.5	527,885		0.0000	1.0000	68.69
83.5	527,885		0.0000	1.0000	68.69
84.5	527,885	29,986	0.0568	0.9432	68.69
85.5	480,930	831	0.0017	0.9983	64.79
86.5	206,519		0.0000	1.0000	64.67
87.5	2,979		0.0000	1.0000	64.67
88.5	2,979		0.0000	1.0000	64.67
89.5	2,979		0.0000	1.0000	64.67
90.5	2,979		0.0000	1.0000	64.67
91.5					64.67

ROCKLAND ELECTRIC COMPANY

ACCOUNT 354.00 TOWERS AND FIXTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1914-2016 EXPERIENCE BAND 1987-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	5,351,859		0.0000	1.0000	100.00
0.5	4,963,456		0.0000	1.0000	100.00
1.5	4,958,074		0.0000	1.0000	100.00
2.5	722,855		0.0000	1.0000	100.00
3.5	722,855		0.0000	1.0000	100.00
4.5	722,855		0.0000	1.0000	100.00
5.5	722,855		0.0000	1.0000	100.00
6.5	626,439		0.0000	1.0000	100.00
7.5	627,448		0.0000	1.0000	100.00
8.5	656,502		0.0000	1.0000	100.00
9.5	656,502		0.0000	1.0000	100.00
10.5	656,502		0.0000	1.0000	100.00
11.5	656,502		0.0000	1.0000	100.00
12.5	1,169,326		0.0000	1.0000	100.00
13.5	1,180,446		0.0000	1.0000	100.00
14.5	1,812,954		0.0000	1.0000	100.00
15.5	2,396,784		0.0000	1.0000	100.00
16.5	2,396,784		0.0000	1.0000	100.00
17.5	2,726,796		0.0000	1.0000	100.00
18.5	2,816,855		0.0000	1.0000	100.00
19.5	2,949,089		0.0000	1.0000	100.00
20.5	3,163,304		0.0000	1.0000	100.00
21.5	3,157,212		0.0000	1.0000	100.00
22.5	3,156,435		0.0000	1.0000	100.00
23.5	3,157,028		0.0000	1.0000	100.00
24.5	2,656,896	104,852	0.0395	0.9605	100.00
25.5	2,617,203		0.0000	1.0000	96.05
26.5	2,617,203		0.0000	1.0000	96.05
27.5	2,688,652		0.0000	1.0000	96.05
28.5	2,832,240		0.0000	1.0000	96.05
29.5	2,832,240		0.0000	1.0000	96.05
30.5	3,532,570		0.0000	1.0000	96.05
31.5	3,536,550		0.0000	1.0000	96.05
32.5	3,553,942		0.0000	1.0000	96.05
33.5	4,080,572	1,860	0.0005	0.9995	96.05
34.5	4,165,009	1,910	0.0005	0.9995	96.01
35.5	4,163,119		0.0000	1.0000	95.97
36.5	4,129,734	7,474	0.0018	0.9982	95.97
37.5	4,158,844	3,274	0.0008	0.9992	95.79
38.5	4,126,515	10,392	0.0025	0.9975	95.72

ROCKLAND ELECTRIC COMPANY

ACCOUNT 354.00 TOWERS AND FIXTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1914-2016 EXPERIENCE BAND 1987-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	4,116,123	517	0.0001	0.9999	95.48
40.5	4,117,507		0.0000	1.0000	95.46
41.5	4,117,507	287	0.0001	0.9999	95.46
42.5	3,604,439	1,248	0.0003	0.9997	95.46
43.5	3,592,071	213	0.0001	0.9999	95.42
44.5	2,971,652		0.0000	1.0000	95.42
45.5	2,492,797	62	0.0000	1.0000	95.42
46.5	2,494,335	2,522	0.0010	0.9990	95.42
47.5	2,175,879	10,498	0.0048	0.9952	95.32
48.5	2,075,323	9,017	0.0043	0.9957	94.86
49.5	1,934,071	15,794	0.0082	0.9918	94.45
50.5	1,640,687	2,612	0.0016	0.9984	93.68
51.5	1,638,075	39,221	0.0239	0.9761	93.53
52.5	2,180,409	13,000	0.0060	0.9940	91.29
53.5	2,166,815	6,230	0.0029	0.9971	90.74
54.5	2,141,321	3,382	0.0016	0.9984	90.48
55.5	2,090,221	69	0.0000	1.0000	90.34
56.5	2,366,712	1,046	0.0004	0.9996	90.34
57.5	2,507,370	103	0.0000	1.0000	90.30
58.5	2,385,030	887	0.0004	0.9996	90.29
59.5	2,384,143	40	0.0000	1.0000	90.26
60.5	1,707,820		0.0000	1.0000	90.26
61.5	1,730,909		0.0000	1.0000	90.26
62.5	1,714,688		0.0000	1.0000	90.26
63.5	1,214,019	1	0.0000	1.0000	90.26
64.5	1,127,748		0.0000	1.0000	90.26
65.5	1,127,748		0.0000	1.0000	90.26
66.5	1,126,405		0.0000	1.0000	90.26
67.5	1,126,405	403	0.0004	0.9996	90.26
68.5	1,126,002		0.0000	1.0000	90.23
69.5	1,126,002	128	0.0001	0.9999	90.23
70.5	1,124,923	13,168	0.0117	0.9883	90.22
71.5	1,111,755		0.0000	1.0000	89.16
72.5	1,142,837	2,771	0.0024	0.9976	89.16
73.5	1,140,066		0.0000	1.0000	88.94
74.5	1,140,066		0.0000	1.0000	88.94
75.5	1,140,066	7,718	0.0068	0.9932	88.94
76.5	1,132,348		0.0000	1.0000	88.34
77.5	1,132,336		0.0000	1.0000	88.34
78.5	1,132,336	21,195	0.0187	0.9813	88.34

ROCKLAND ELECTRIC COMPANY

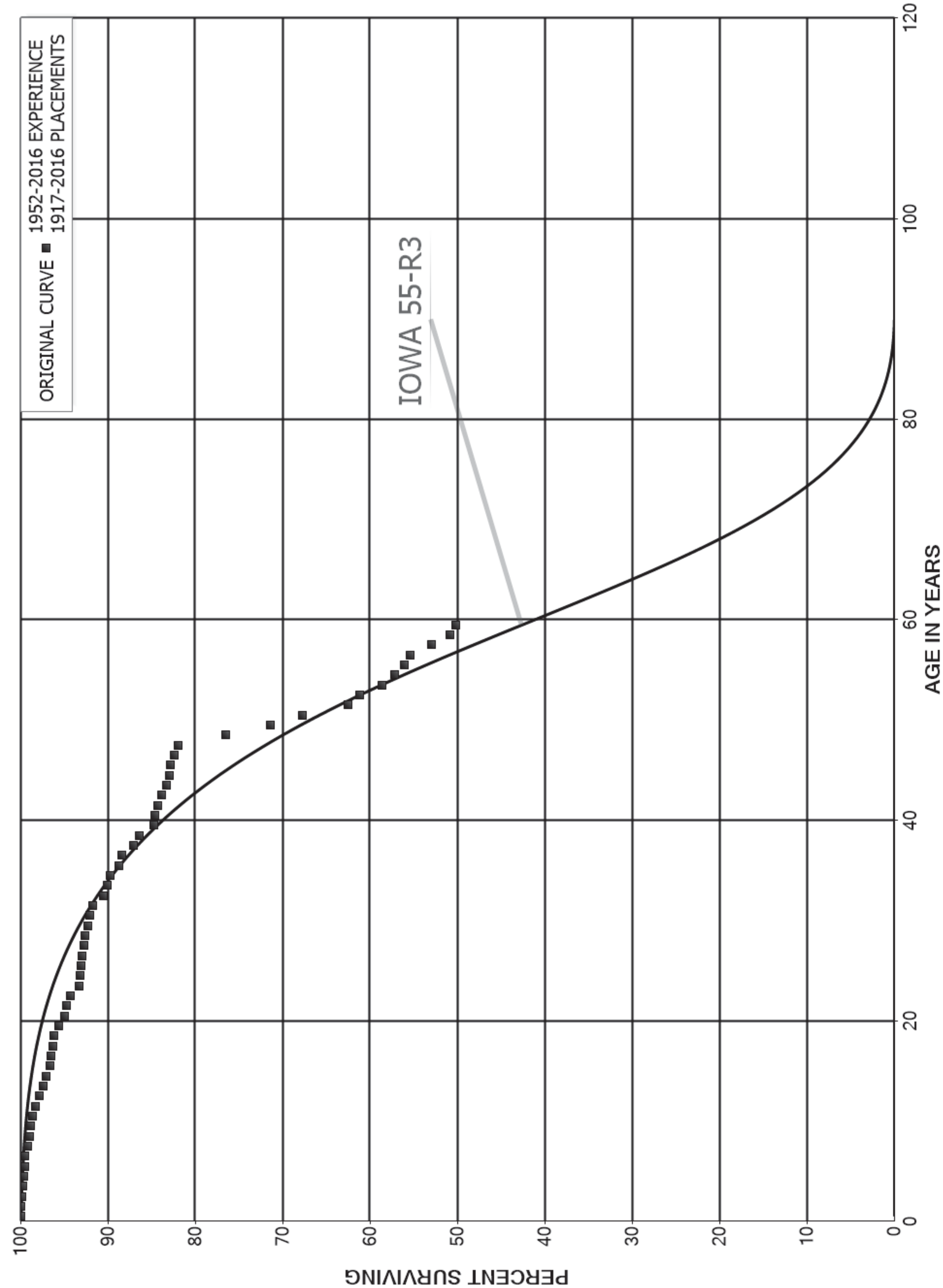
ACCOUNT 354.00 TOWERS AND FIXTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1914-2016 EXPERIENCE BAND 1987-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	1,111,141		0.0000	1.0000	86.69
80.5	1,111,141	1,703	0.0015	0.9985	86.69
81.5	1,109,439		0.0000	1.0000	86.55
82.5	527,885		0.0000	1.0000	86.55
83.5	527,885		0.0000	1.0000	86.55
84.5	527,885	29,986	0.0568	0.9432	86.55
85.5	480,930	831	0.0017	0.9983	81.64
86.5	206,519		0.0000	1.0000	81.50
87.5	2,979		0.0000	1.0000	81.50
88.5	2,979		0.0000	1.0000	81.50
89.5	2,979		0.0000	1.0000	81.50
90.5	2,979		0.0000	1.0000	81.50
91.5					81.50

ROCKLAND ELECTRIC COMPANY
ACCOUNTS 355.00 AND 355.10 POLES AND FIXTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES



ROCKLAND ELECTRIC COMPANY

ACCOUNTS 355.00 AND 355.10 POLES AND FIXTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1917-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	82,848,804	1,817	0.0000	1.0000	100.00
0.5	79,722,950	68,037	0.0009	0.9991	100.00
1.5	78,365,954	63,062	0.0008	0.9992	99.91
2.5	70,589,551	48,347	0.0007	0.9993	99.83
3.5	69,436,028	133,075	0.0019	0.9981	99.76
4.5	64,863,242	35,842	0.0006	0.9994	99.57
5.5	57,545,481	26,469	0.0005	0.9995	99.52
6.5	57,108,422	195,931	0.0034	0.9966	99.47
7.5	56,210,546	95,402	0.0017	0.9983	99.13
8.5	46,647,749	66,261	0.0014	0.9986	98.96
9.5	40,723,339	97,321	0.0024	0.9976	98.82
10.5	29,119,022	97,489	0.0033	0.9967	98.59
11.5	28,866,397	113,998	0.0039	0.9961	98.26
12.5	28,418,300	122,995	0.0043	0.9957	97.87
13.5	27,234,459	93,725	0.0034	0.9966	97.44
14.5	26,104,485	119,080	0.0046	0.9954	97.11
15.5	25,129,538	53,144	0.0021	0.9979	96.67
16.5	25,079,802	49,496	0.0020	0.9980	96.46
17.5	24,042,057	34,555	0.0014	0.9986	96.27
18.5	23,712,530	131,982	0.0056	0.9944	96.13
19.5	22,959,727	155,951	0.0068	0.9932	95.60
20.5	22,396,440	50,580	0.0023	0.9977	94.95
21.5	22,208,663	110,423	0.0050	0.9950	94.73
22.5	21,949,890	239,893	0.0109	0.9891	94.26
23.5	21,248,274	13,666	0.0006	0.9994	93.23
24.5	20,119,182	28,168	0.0014	0.9986	93.17
25.5	20,039,540	14,665	0.0007	0.9993	93.04
26.5	19,918,266	46,538	0.0023	0.9977	92.97
27.5	19,797,568	22,536	0.0011	0.9989	92.76
28.5	19,591,518	80,475	0.0041	0.9959	92.65
29.5	19,515,158	35,020	0.0018	0.9982	92.27
30.5	19,472,586	78,537	0.0040	0.9960	92.10
31.5	19,132,440	262,231	0.0137	0.9863	91.73
32.5	18,815,087	84,823	0.0045	0.9955	90.48
33.5	18,646,660	81,243	0.0044	0.9956	90.07
34.5	18,528,319	205,737	0.0111	0.9889	89.68
35.5	16,227,884	60,010	0.0037	0.9963	88.68
36.5	16,153,288	238,539	0.0148	0.9852	88.35
37.5	15,715,922	119,292	0.0076	0.9924	87.05
38.5	15,218,700	293,075	0.0193	0.9807	86.39

ROCKLAND ELECTRIC COMPANY

ACCOUNTS 355.00 AND 355.10 POLES AND FIXTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1917-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	14,907,107	20,344	0.0014	0.9986	84.72
40.5	14,033,312	55,626	0.0040	0.9960	84.61
41.5	13,396,606	62,592	0.0047	0.9953	84.27
42.5	8,081,026	52,405	0.0065	0.9935	83.88
43.5	8,011,991	38,312	0.0048	0.9952	83.33
44.5	5,355,150	9,145	0.0017	0.9983	82.94
45.5	1,870,697	8,163	0.0044	0.9956	82.79
46.5	1,862,534	9,681	0.0052	0.9948	82.43
47.5	1,560,195	104,644	0.0671	0.9329	82.00
48.5	1,121,302	75,607	0.0674	0.9326	76.50
49.5	708,206	35,564	0.0502	0.9498	71.35
50.5	669,394	52,390	0.0783	0.9217	67.76
51.5	612,806	12,689	0.0207	0.9793	62.46
52.5	579,389	24,662	0.0426	0.9574	61.17
53.5	528,617	12,157	0.0230	0.9770	58.56
54.5	399,569	8,279	0.0207	0.9793	57.22
55.5	212,399	2,307	0.0109	0.9891	56.03
56.5	204,918	8,960	0.0437	0.9563	55.42
57.5	129,193	5,186	0.0401	0.9599	53.00
58.5	101,525	1,443	0.0142	0.9858	50.87
59.5	96,563	4,983	0.0516	0.9484	50.15
60.5	91,292	1,177	0.0129	0.9871	47.56
61.5	38,660	251	0.0065	0.9935	46.95
62.5	38,023	132	0.0035	0.9965	46.64
63.5	30,183	1	0.0000	1.0000	46.48
64.5	30,101	90	0.0030	0.9970	46.48
65.5	28,494	90	0.0032	0.9968	46.34
66.5	28,212	446	0.0158	0.9842	46.19
67.5	27,766	319	0.0115	0.9885	45.46
68.5	24,177	263	0.0109	0.9891	44.94
69.5	19,937	48	0.0024	0.9976	44.45
70.5	14,881		0.0000	1.0000	44.35
71.5	14,518		0.0000	1.0000	44.35
72.5	14,518	14	0.0010	0.9990	44.35
73.5	14,496	106	0.0073	0.9927	44.30
74.5	14,391	268	0.0186	0.9814	43.98
75.5	14,097	170	0.0121	0.9879	43.16
76.5	13,885	129	0.0093	0.9907	42.64
77.5	12,028		0.0000	1.0000	42.24
78.5	11,162		0.0000	1.0000	42.24

ROCKLAND ELECTRIC COMPANY

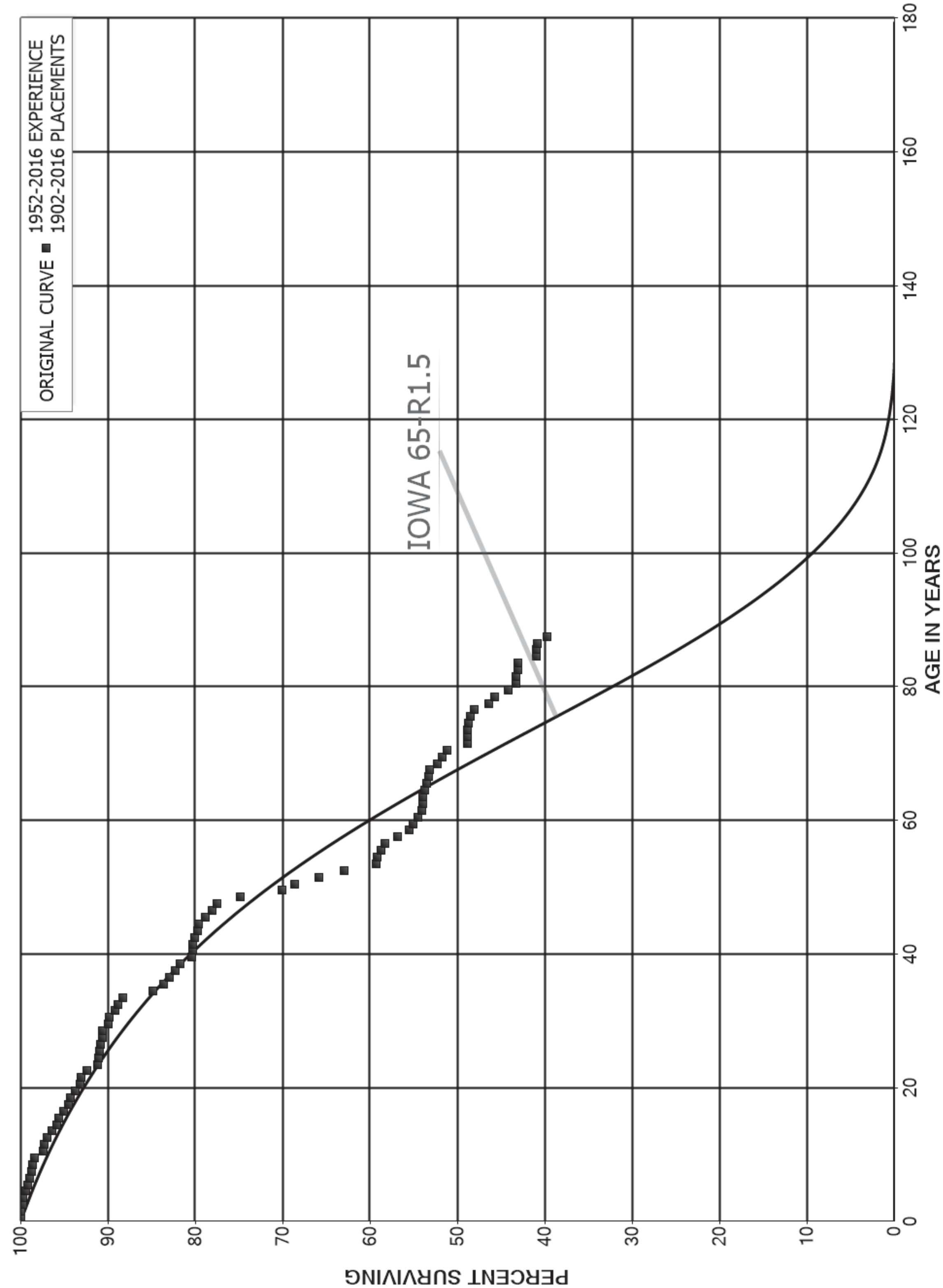
ACCOUNTS 355.00 AND 355.10 POLES AND FIXTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1917-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	11,162	158	0.0141	0.9859	42.24
80.5	10,882		0.0000	1.0000	41.65
81.5	5,875		0.0000	1.0000	41.65
82.5	5,875		0.0000	1.0000	41.65
83.5	5,875		0.0000	1.0000	41.65
84.5	5,825		0.0000	1.0000	41.65
85.5	5,825		0.0000	1.0000	41.65
86.5	5,303		0.0000	1.0000	41.65
87.5	1,725		0.0000	1.0000	41.65
88.5	1,725		0.0000	1.0000	41.65
89.5					41.65

ROCKLAND ELECTRIC COMPANY
ACCOUNTS 356.00 AND 356.10 OVERHEAD CONDUCTORS AND DEVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



ROCKLAND ELECTRIC COMPANY

ACCOUNTS 356.00 AND 356.10 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1902-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	64,347,561	1,098	0.0000	1.0000	100.00
0.5	63,545,109	48,711	0.0008	0.9992	100.00
1.5	63,307,942	94,292	0.0015	0.9985	99.92
2.5	41,652,410	23,954	0.0006	0.9994	99.77
3.5	41,313,495	125,863	0.0030	0.9970	99.72
4.5	40,194,669	82,138	0.0020	0.9980	99.41
5.5	36,332,821	79,898	0.0022	0.9978	99.21
6.5	36,052,523	78,325	0.0022	0.9978	98.99
7.5	35,955,899	48,307	0.0013	0.9987	98.78
8.5	31,550,877	63,255	0.0020	0.9980	98.64
9.5	27,108,529	293,007	0.0108	0.9892	98.44
10.5	19,138,465	9,594	0.0005	0.9995	97.38
11.5	19,154,203	76,008	0.0040	0.9960	97.33
12.5	19,085,387	105,845	0.0055	0.9945	96.95
13.5	18,987,306	111,921	0.0059	0.9941	96.41
14.5	18,817,915	41,086	0.0022	0.9978	95.84
15.5	18,297,539	100,473	0.0055	0.9945	95.63
16.5	18,208,571	117,336	0.0064	0.9936	95.11
17.5	18,044,352	38,202	0.0021	0.9979	94.49
18.5	18,006,698	114,798	0.0064	0.9936	94.29
19.5	17,898,740	100,668	0.0056	0.9944	93.69
20.5	18,068,373	27,741	0.0015	0.9985	93.16
21.5	18,010,891	123,522	0.0069	0.9931	93.02
22.5	18,078,548	239,838	0.0133	0.9867	92.38
23.5	17,802,543	26,982	0.0015	0.9985	91.16
24.5	16,970,091	12,704	0.0007	0.9993	91.02
25.5	16,972,369	30,682	0.0018	0.9982	90.95
26.5	16,948,752	26,389	0.0016	0.9984	90.79
27.5	16,831,748	11,277	0.0007	0.9993	90.65
28.5	16,845,287	118,522	0.0070	0.9930	90.59
29.5	16,752,288	28,223	0.0017	0.9983	89.95
30.5	16,724,065	113,684	0.0068	0.9932	89.80
31.5	16,496,509	65,808	0.0040	0.9960	89.19
32.5	16,426,878	107,738	0.0066	0.9934	88.83
33.5	16,307,573	627,162	0.0385	0.9615	88.25
34.5	14,168,371	200,180	0.0141	0.9859	84.85
35.5	12,326,098	101,701	0.0083	0.9917	83.65
36.5	12,208,010	104,778	0.0086	0.9914	82.96
37.5	12,025,848	73,153	0.0061	0.9939	82.25
38.5	11,666,993	200,747	0.0172	0.9828	81.75

ROCKLAND ELECTRIC COMPANY

ACCOUNTS 356.00 AND 356.10 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1902-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	11,434,326	6,911	0.0006	0.9994	80.35
40.5	10,884,521	7,394	0.0007	0.9993	80.30
41.5	10,124,214	17,879	0.0018	0.9982	80.24
42.5	7,725,880	36,638	0.0047	0.9953	80.10
43.5	7,666,242	9,948	0.0013	0.9987	79.72
44.5	5,985,492	60,739	0.0101	0.9899	79.62
45.5	3,739,845	37,011	0.0099	0.9901	78.81
46.5	3,623,307	26,809	0.0074	0.9926	78.03
47.5	2,999,072	99,790	0.0333	0.9667	77.45
48.5	2,584,799	166,119	0.0643	0.9357	74.87
49.5	1,913,518	39,129	0.0204	0.9796	70.06
50.5	1,721,145	71,076	0.0413	0.9587	68.63
51.5	1,639,574	70,740	0.0431	0.9569	65.80
52.5	1,540,910	89,620	0.0582	0.9418	62.96
53.5	1,427,858	4,135	0.0029	0.9971	59.30
54.5	1,362,004	9,979	0.0073	0.9927	59.12
55.5	1,142,611	8,310	0.0073	0.9927	58.69
56.5	1,130,460	27,376	0.0242	0.9758	58.26
57.5	972,833	22,789	0.0234	0.9766	56.85
58.5	900,179	6,906	0.0077	0.9923	55.52
59.5	892,007	8,723	0.0098	0.9902	55.10
60.5	878,974	7,069	0.0080	0.9920	54.56
61.5	799,199	2,120	0.0027	0.9973	54.12
62.5	784,738	984	0.0013	0.9987	53.97
63.5	749,916	1,811	0.0024	0.9976	53.91
64.5	688,456	3,860	0.0056	0.9944	53.78
65.5	683,900	2,835	0.0041	0.9959	53.47
66.5	661,360	454	0.0007	0.9993	53.25
67.5	642,128	10,671	0.0166	0.9834	53.22
68.5	617,805	6,636	0.0107	0.9893	52.33
69.5	599,354	6,341	0.0106	0.9894	51.77
70.5	592,790	28,013	0.0473	0.9527	51.22
71.5	564,709	207	0.0004	0.9996	48.80
72.5	564,502		0.0000	1.0000	48.78
73.5	563,468	514	0.0009	0.9991	48.78
74.5	562,954	2,189	0.0039	0.9961	48.74
75.5	560,614	6,174	0.0110	0.9890	48.55
76.5	554,388	18,901	0.0341	0.9659	48.02
77.5	535,487	7,245	0.0135	0.9865	46.38
78.5	526,292	18,331	0.0348	0.9652	45.75

ROCKLAND ELECTRIC COMPANY

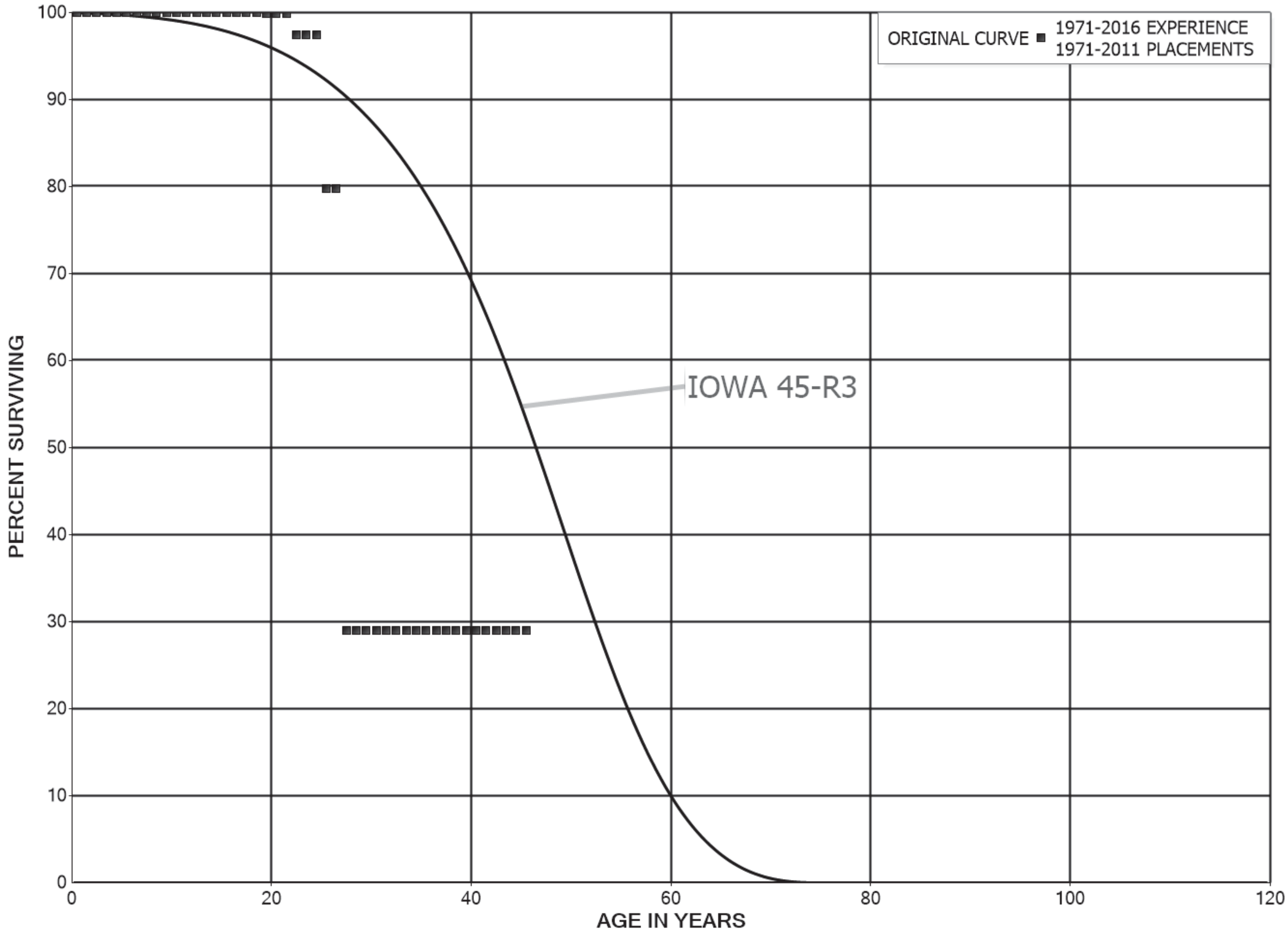
ACCOUNTS 356.00 AND 356.10 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1902-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	507,520	9,542	0.0188	0.9812	44.16
80.5	497,978	447	0.0009	0.9991	43.33
81.5	487,971	2,121	0.0043	0.9957	43.29
82.5	484,718	253	0.0005	0.9995	43.10
83.5	484,465	24,177	0.0499	0.9501	43.08
84.5	459,820		0.0000	1.0000	40.93
85.5	235,421	501	0.0021	0.9979	40.93
86.5	232,002	6,173	0.0266	0.9734	40.84
87.5	74,710		0.0000	1.0000	39.75
88.5	33,508		0.0000	1.0000	39.75
89.5	19,646		0.0000	1.0000	39.75
90.5	16,055		0.0000	1.0000	39.75
91.5	5,523		0.0000	1.0000	39.75
92.5	3,896		0.0000	1.0000	39.75
93.5	1,788	176	0.0987	0.9013	39.75
94.5	1,601		0.0000	1.0000	35.83
95.5	1,601		0.0000	1.0000	35.83
96.5	1,601		0.0000	1.0000	35.83
97.5	1,601		0.0000	1.0000	35.83
98.5	1,600		0.0000	1.0000	35.83
99.5					35.83

ROCKLAND ELECTRIC COMPANY
ACCOUNT 357.00 UNDERGROUND CONDUIT
ORIGINAL AND SMOOTH SURVIVOR CURVES



ROCKLAND ELECTRIC COMPANY

ACCOUNT 357.00 UNDERGROUND CONDUIT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1971-2011 EXPERIENCE BAND 1971-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	7,156,051		0.0000	1.0000	100.00
0.5	7,156,051		0.0000	1.0000	100.00
1.5	7,156,051		0.0000	1.0000	100.00
2.5	7,156,051		0.0000	1.0000	100.00
3.5	7,156,051		0.0000	1.0000	100.00
4.5	7,156,051		0.0000	1.0000	100.00
5.5	3,971,996		0.0000	1.0000	100.00
6.5	3,971,996		0.0000	1.0000	100.00
7.5	3,971,996		0.0000	1.0000	100.00
8.5	3,971,996		0.0000	1.0000	100.00
9.5	3,971,996		0.0000	1.0000	100.00
10.5	2,031,516		0.0000	1.0000	100.00
11.5	2,031,516		0.0000	1.0000	100.00
12.5	2,031,516		0.0000	1.0000	100.00
13.5	922,170		0.0000	1.0000	100.00
14.5	922,170		0.0000	1.0000	100.00
15.5	922,170		0.0000	1.0000	100.00
16.5	922,170		0.0000	1.0000	100.00
17.5	922,170	45	0.0000	1.0000	100.00
18.5	922,125	1,239	0.0013	0.9987	100.00
19.5	920,886		0.0000	1.0000	99.86
20.5	920,886		0.0000	1.0000	99.86
21.5	920,886	22,679	0.0246	0.9754	99.86
22.5	898,207		0.0000	1.0000	97.40
23.5	898,207		0.0000	1.0000	97.40
24.5	898,207	163,054	0.1815	0.8185	97.40
25.5	735,153		0.0000	1.0000	79.72
26.5	735,153	468,318	0.6370	0.3630	79.72
27.5	266,835		0.0000	1.0000	28.94
28.5	266,835		0.0000	1.0000	28.94
29.5	266,835		0.0000	1.0000	28.94
30.5	266,835		0.0000	1.0000	28.94
31.5	266,835		0.0000	1.0000	28.94
32.5	266,835		0.0000	1.0000	28.94
33.5	266,835		0.0000	1.0000	28.94
34.5	80,840		0.0000	1.0000	28.94
35.5	80,840		0.0000	1.0000	28.94
36.5	80,840		0.0000	1.0000	28.94
37.5	80,840		0.0000	1.0000	28.94
38.5	80,840		0.0000	1.0000	28.94

ROCKLAND ELECTRIC COMPANY

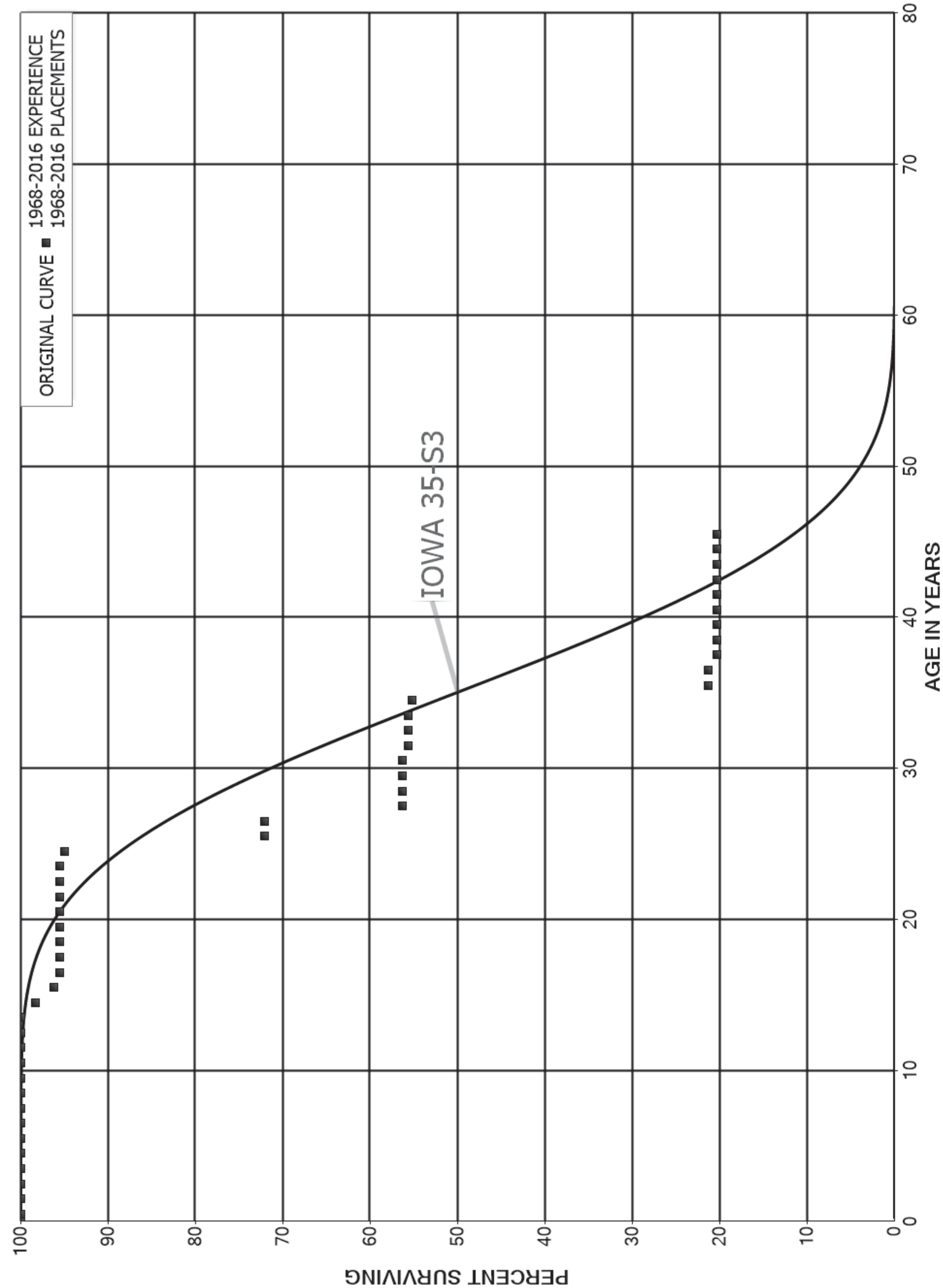
ACCOUNT 357.00 UNDERGROUND CONDUIT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1971-2011 EXPERIENCE BAND 1971-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	80,840		0.0000	1.0000	28.94
40.5	80,840		0.0000	1.0000	28.94
41.5	80,840		0.0000	1.0000	28.94
42.5	80,840		0.0000	1.0000	28.94
43.5	80,840		0.0000	1.0000	28.94
44.5	73,458		0.0000	1.0000	28.94
45.5					28.94

ROCKLAND ELECTRIC COMPANY
ACCOUNT 358.00 UNDERGROUND CONDUCTORS AND DEVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



ROCKLAND ELECTRIC COMPANY

ACCOUNT 358.00 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1968-2016 EXPERIENCE BAND 1968-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	17,668,274		0.0000	1.0000	100.00
0.5	17,334,787		0.0000	1.0000	100.00
1.5	17,334,787		0.0000	1.0000	100.00
2.5	17,333,075		0.0000	1.0000	100.00
3.5	17,333,075		0.0000	1.0000	100.00
4.5	17,333,075		0.0000	1.0000	100.00
5.5	5,067,061		0.0000	1.0000	100.00
6.5	5,067,061		0.0000	1.0000	100.00
7.5	5,067,061		0.0000	1.0000	100.00
8.5	5,067,061		0.0000	1.0000	100.00
9.5	5,067,061		0.0000	1.0000	100.00
10.5	2,650,010		0.0000	1.0000	100.00
11.5	2,650,010	764	0.0003	0.9997	100.00
12.5	2,649,246		0.0000	1.0000	99.97
13.5	1,723,276	29,572	0.0172	0.9828	99.97
14.5	1,647,550	34,494	0.0209	0.9791	98.26
15.5	1,613,056	12,479	0.0077	0.9923	96.20
16.5	1,600,577		0.0000	1.0000	95.45
17.5	1,510,230		0.0000	1.0000	95.45
18.5	1,510,230		0.0000	1.0000	95.45
19.5	1,510,230		0.0000	1.0000	95.45
20.5	1,510,230		0.0000	1.0000	95.45
21.5	1,510,230	2	0.0000	1.0000	95.45
22.5	1,510,228		0.0000	1.0000	95.45
23.5	1,510,228	7,133	0.0047	0.9953	95.45
24.5	1,470,601	355,587	0.2418	0.7582	95.00
25.5	1,115,014		0.0000	1.0000	72.03
26.5	1,115,014	243,807	0.2187	0.7813	72.03
27.5	871,207	509	0.0006	0.9994	56.28
28.5	870,698		0.0000	1.0000	56.25
29.5	870,698		0.0000	1.0000	56.25
30.5	870,698	9,016	0.0104	0.9896	56.25
31.5	861,682		0.0000	1.0000	55.67
32.5	861,682	713	0.0008	0.9992	55.67
33.5	836,011	7,202	0.0086	0.9914	55.62
34.5	243,156	149,290	0.6140	0.3860	55.14
35.5	93,866		0.0000	1.0000	21.29
36.5	93,866	4,589	0.0489	0.9511	21.29
37.5	89,277		0.0000	1.0000	20.25
38.5	89,277		0.0000	1.0000	20.25

ROCKLAND ELECTRIC COMPANY

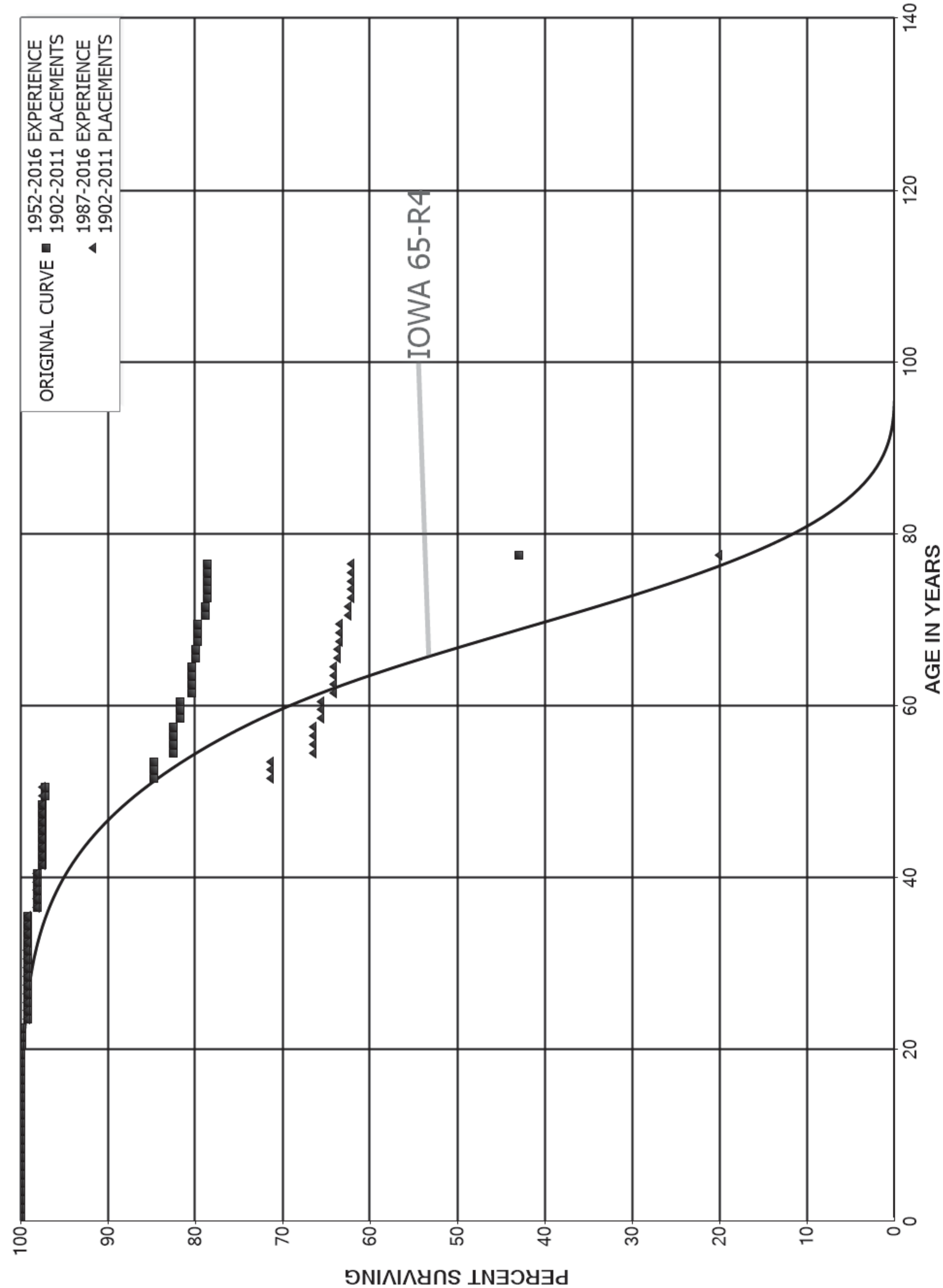
ACCOUNT 358.00 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1968-2016 EXPERIENCE BAND 1968-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	89,277		0.0000	1.0000	20.25
40.5	89,277		0.0000	1.0000	20.25
41.5	89,277		0.0000	1.0000	20.25
42.5	89,277		0.0000	1.0000	20.25
43.5	89,277		0.0000	1.0000	20.25
44.5	72,623		0.0000	1.0000	20.25
45.5					20.25

ROCKLAND ELECTRIC COMPANY
ACCOUNT 359.00 ROADS AND TRAILS
ORIGINAL AND SMOOTH SURVIVOR CURVES



ROCKLAND ELECTRIC COMPANY

ACCOUNT 359.00 ROADS AND TRAILS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1902-2011 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,274,133		0.0000	1.0000	100.00
0.5	1,274,133		0.0000	1.0000	100.00
1.5	1,283,349		0.0000	1.0000	100.00
2.5	1,283,349		0.0000	1.0000	100.00
3.5	1,286,891		0.0000	1.0000	100.00
4.5	1,286,891		0.0000	1.0000	100.00
5.5	1,227,280		0.0000	1.0000	100.00
6.5	1,227,280		0.0000	1.0000	100.00
7.5	1,227,280		0.0000	1.0000	100.00
8.5	951,165		0.0000	1.0000	100.00
9.5	951,165		0.0000	1.0000	100.00
10.5	951,165		0.0000	1.0000	100.00
11.5	951,382		0.0000	1.0000	100.00
12.5	951,382		0.0000	1.0000	100.00
13.5	951,389		0.0000	1.0000	100.00
14.5	951,410		0.0000	1.0000	100.00
15.5	951,585		0.0000	1.0000	100.00
16.5	951,616		0.0000	1.0000	100.00
17.5	951,664		0.0000	1.0000	100.00
18.5	951,664		0.0000	1.0000	100.00
19.5	951,664	1,767	0.0019	0.9981	100.00
20.5	949,897		0.0000	1.0000	99.81
21.5	949,897		0.0000	1.0000	99.81
22.5	953,578	5,748	0.0060	0.9940	99.81
23.5	877,900		0.0000	1.0000	99.21
24.5	804,834		0.0000	1.0000	99.21
25.5	804,834		0.0000	1.0000	99.21
26.5	804,834		0.0000	1.0000	99.21
27.5	799,036		0.0000	1.0000	99.21
28.5	799,036		0.0000	1.0000	99.21
29.5	799,036		0.0000	1.0000	99.21
30.5	799,036		0.0000	1.0000	99.21
31.5	799,036	690	0.0009	0.9991	99.21
32.5	798,346		0.0000	1.0000	99.13
33.5	798,346		0.0000	1.0000	99.13
34.5	798,346		0.0000	1.0000	99.13
35.5	461,307	4,697	0.0102	0.9898	99.13
36.5	456,610		0.0000	1.0000	98.12
37.5	418,547		0.0000	1.0000	98.12
38.5	390,014		0.0000	1.0000	98.12

ROCKLAND ELECTRIC COMPANY

ACCOUNT 359.00 ROADS AND TRAILS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1902-2011 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	390,014		0.0000	1.0000	98.12
40.5	279,138	1,891	0.0068	0.9932	98.12
41.5	256,145		0.0000	1.0000	97.45
42.5	242,095		0.0000	1.0000	97.45
43.5	242,095		0.0000	1.0000	97.45
44.5	104,391		0.0000	1.0000	97.45
45.5	30,498		0.0000	1.0000	97.45
46.5	12,945		0.0000	1.0000	97.45
47.5	12,945		0.0000	1.0000	97.45
48.5	12,945	31	0.0024	0.9976	97.45
49.5	15,609		0.0000	1.0000	97.22
50.5	15,609	2,005	0.1285	0.8715	97.22
51.5	13,286		0.0000	1.0000	84.73
52.5	13,286		0.0000	1.0000	84.73
53.5	13,286	353	0.0266	0.9734	84.73
54.5	12,933		0.0000	1.0000	82.48
55.5	12,863		0.0000	1.0000	82.48
56.5	12,863		0.0000	1.0000	82.48
57.5	12,863	111	0.0086	0.9914	82.48
58.5	12,752		0.0000	1.0000	81.77
59.5	12,752		0.0000	1.0000	81.77
60.5	12,752	217	0.0170	0.9830	81.77
61.5	12,535		0.0000	1.0000	80.38
62.5	12,535		0.0000	1.0000	80.38
63.5	12,535		0.0000	1.0000	80.38
64.5	11,763	71	0.0060	0.9940	80.38
65.5	11,692		0.0000	1.0000	79.89
66.5	11,692	24	0.0021	0.9979	79.89
67.5	11,668	7	0.0006	0.9994	79.73
68.5	8,229		0.0000	1.0000	79.68
69.5	8,229	89	0.0108	0.9892	79.68
70.5	8,140		0.0000	1.0000	78.82
71.5	8,140	24	0.0029	0.9971	78.82
72.5	8,116		0.0000	1.0000	78.59
73.5	8,116		0.0000	1.0000	78.59
74.5	8,116		0.0000	1.0000	78.59
75.5	8,116		0.0000	1.0000	78.59
76.5	8,116	3,681	0.4535	0.5465	78.59
77.5	4,435		0.0000	1.0000	42.94
78.5	4,435		0.0000	1.0000	42.94

ROCKLAND ELECTRIC COMPANY

ACCOUNT 359.00 ROADS AND TRAILS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1902-2011 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	4,414		0.0000	1.0000	42.94
80.5	4,414		0.0000	1.0000	42.94
81.5	4,414		0.0000	1.0000	42.94
82.5	4,414		0.0000	1.0000	42.94
83.5	4,414		0.0000	1.0000	42.94
84.5	4,414		0.0000	1.0000	42.94
85.5	4,414		0.0000	1.0000	42.94
86.5	4,414		0.0000	1.0000	42.94
87.5	4,414	2,695	0.6105	0.3895	42.94
88.5					16.73

ROCKLAND ELECTRIC COMPANY

ACCOUNT 359.00 ROADS AND TRAILS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1902-2011 EXPERIENCE BAND 1987-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	477,024		0.0000	1.0000	100.00
0.5	477,024		0.0000	1.0000	100.00
1.5	486,240		0.0000	1.0000	100.00
2.5	486,240		0.0000	1.0000	100.00
3.5	486,240		0.0000	1.0000	100.00
4.5	486,240		0.0000	1.0000	100.00
5.5	763,666		0.0000	1.0000	100.00
6.5	763,666		0.0000	1.0000	100.00
7.5	801,730		0.0000	1.0000	100.00
8.5	559,896		0.0000	1.0000	100.00
9.5	559,896		0.0000	1.0000	100.00
10.5	670,772		0.0000	1.0000	100.00
11.5	691,874		0.0000	1.0000	100.00
12.5	706,613		0.0000	1.0000	100.00
13.5	706,613		0.0000	1.0000	100.00
14.5	844,318		0.0000	1.0000	100.00
15.5	918,211		0.0000	1.0000	100.00
16.5	942,228		0.0000	1.0000	100.00
17.5	942,228		0.0000	1.0000	100.00
18.5	942,228		0.0000	1.0000	100.00
19.5	942,228	1,767	0.0019	0.9981	100.00
20.5	940,461		0.0000	1.0000	99.81
21.5	942,670		0.0000	1.0000	99.81
22.5	942,670	5,748	0.0061	0.9939	99.81
23.5	865,273		0.0000	1.0000	99.20
24.5	792,207		0.0000	1.0000	99.20
25.5	792,614		0.0000	1.0000	99.20
26.5	792,614		0.0000	1.0000	99.20
27.5	786,816		0.0000	1.0000	99.20
28.5	786,816		0.0000	1.0000	99.20
29.5	786,816		0.0000	1.0000	99.20
30.5	786,816		0.0000	1.0000	99.20
31.5	788,821	690	0.0009	0.9991	99.20
32.5	788,131		0.0000	1.0000	99.12
33.5	788,131		0.0000	1.0000	99.12
34.5	788,904		0.0000	1.0000	99.12
35.5	451,866	4,697	0.0104	0.9896	99.12
36.5	447,169		0.0000	1.0000	98.09
37.5	409,105		0.0000	1.0000	98.09
38.5	384,115		0.0000	1.0000	98.09

ROCKLAND ELECTRIC COMPANY

ACCOUNT 359.00 ROADS AND TRAILS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1902-2011 EXPERIENCE BAND 1987-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	384,115		0.0000	1.0000	98.09
40.5	273,239	1,891	0.0069	0.9931	98.09
41.5	250,246		0.0000	1.0000	97.41
42.5	236,196		0.0000	1.0000	97.41
43.5	236,196		0.0000	1.0000	97.41
44.5	98,492		0.0000	1.0000	97.41
45.5	24,599		0.0000	1.0000	97.41
46.5	7,263		0.0000	1.0000	97.41
47.5	7,263		0.0000	1.0000	97.41
48.5	7,270		0.0000	1.0000	97.41
49.5	7,291		0.0000	1.0000	97.41
50.5	7,466	2,005	0.2686	0.7314	97.41
51.5	5,143		0.0000	1.0000	71.25
52.5	5,191		0.0000	1.0000	71.25
53.5	5,191	353	0.0680	0.9320	71.25
54.5	4,838		0.0000	1.0000	66.40
55.5	4,768		0.0000	1.0000	66.40
56.5	4,768		0.0000	1.0000	66.40
57.5	8,449	111	0.0131	0.9869	66.40
58.5	10,057		0.0000	1.0000	65.53
59.5	10,057		0.0000	1.0000	65.53
60.5	10,057	217	0.0216	0.9784	65.53
61.5	9,840		0.0000	1.0000	64.12
62.5	9,840		0.0000	1.0000	64.12
63.5	9,840		0.0000	1.0000	64.12
64.5	9,068	71	0.0078	0.9922	64.12
65.5	8,997		0.0000	1.0000	63.61
66.5	8,997	24	0.0027	0.9973	63.61
67.5	8,973	7	0.0008	0.9992	63.44
68.5	5,534		0.0000	1.0000	63.40
69.5	5,534	89	0.0161	0.9839	63.40
70.5	5,445		0.0000	1.0000	62.38
71.5	5,445	24	0.0044	0.9956	62.38
72.5	5,421		0.0000	1.0000	62.10
73.5	5,421		0.0000	1.0000	62.10
74.5	5,421		0.0000	1.0000	62.10
75.5	5,421		0.0000	1.0000	62.10
76.5	5,421	3,681	0.6790	0.3210	62.10
77.5	1,740		0.0000	1.0000	19.93
78.5	1,740		0.0000	1.0000	19.93

ROCKLAND ELECTRIC COMPANY

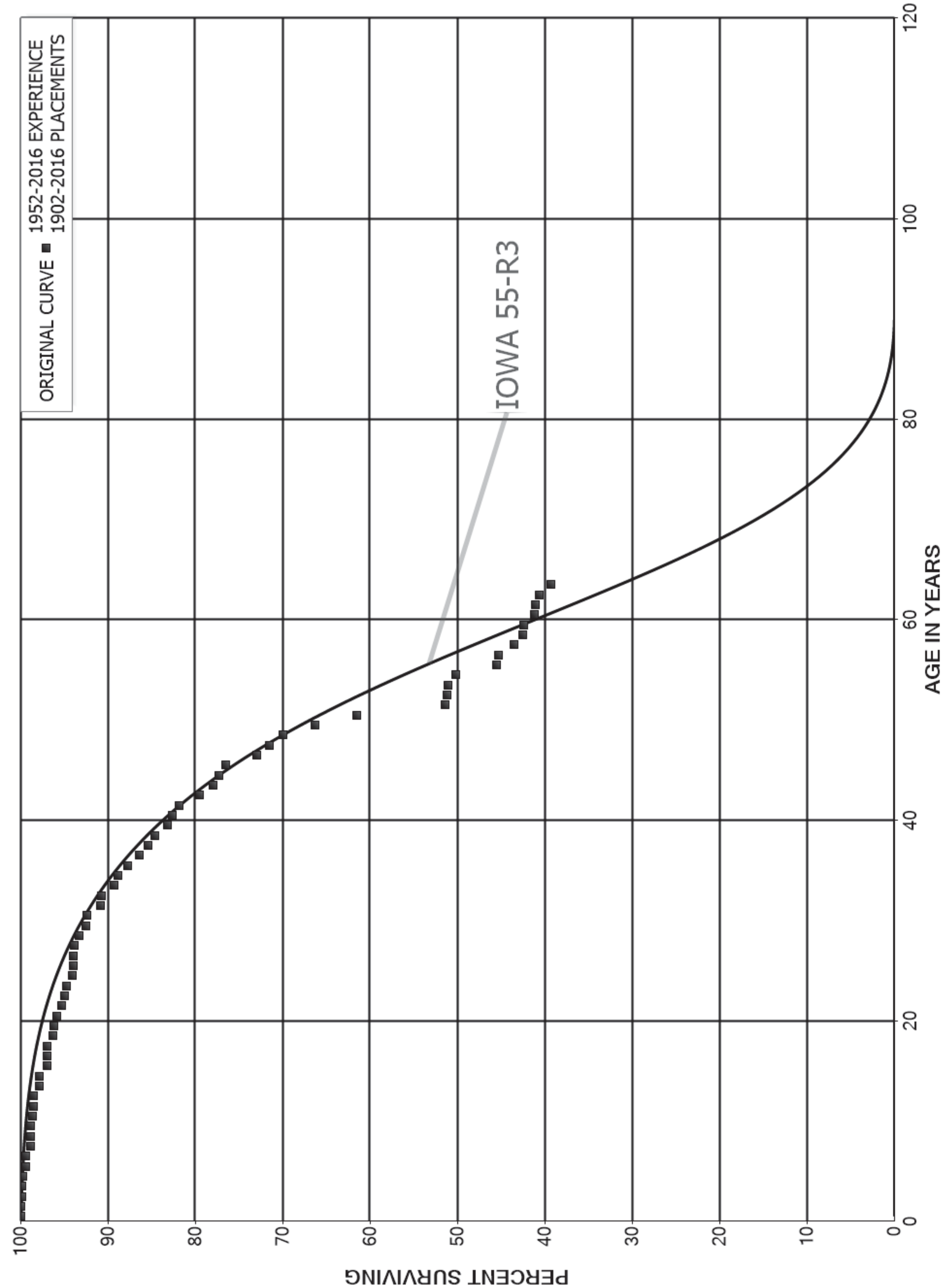
ACCOUNT 359.00 ROADS AND TRAILS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1902-2011 EXPERIENCE BAND 1987-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	1,719		0.0000	1.0000	19.93
80.5	1,719		0.0000	1.0000	19.93
81.5	1,719		0.0000	1.0000	19.93
82.5	1,719		0.0000	1.0000	19.93
83.5	1,719		0.0000	1.0000	19.93
84.5	4,414		0.0000	1.0000	19.93
85.5	4,414		0.0000	1.0000	19.93
86.5	4,414		0.0000	1.0000	19.93
87.5	4,414	2,695	0.6105	0.3895	19.93
88.5					7.76

ROCKLAND ELECTRIC COMPANY
ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



ROCKLAND ELECTRIC COMPANY

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1902-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	19,767,431		0.0000	1.0000	100.00
0.5	19,435,547		0.0000	1.0000	100.00
1.5	19,418,060	29,489	0.0015	0.9985	100.00
2.5	18,761,146	3,278	0.0002	0.9998	99.85
3.5	18,134,113	15,919	0.0009	0.9991	99.83
4.5	15,583,746	45,880	0.0029	0.9971	99.74
5.5	12,751,099	6,260	0.0005	0.9995	99.45
6.5	12,074,969	63,314	0.0052	0.9948	99.40
7.5	11,715,077	4,607	0.0004	0.9996	98.88
8.5	11,092,112	4,255	0.0004	0.9996	98.84
9.5	10,445,922	17,246	0.0017	0.9983	98.80
10.5	10,155,545	14,309	0.0014	0.9986	98.64
11.5	8,973,253	2,918	0.0003	0.9997	98.50
12.5	7,180,625	43,945	0.0061	0.9939	98.47
13.5	6,159,561	5,026	0.0008	0.9992	97.87
14.5	5,395,894	45,018	0.0083	0.9917	97.79
15.5	5,228,333	801	0.0002	0.9998	96.97
16.5	5,068,920	2,225	0.0004	0.9996	96.96
17.5	4,843,207	33,046	0.0068	0.9932	96.91
18.5	4,763,210	2,069	0.0004	0.9996	96.25
19.5	4,566,139	19,796	0.0043	0.9957	96.21
20.5	4,503,342	24,377	0.0054	0.9946	95.79
21.5	4,124,087	13,526	0.0033	0.9967	95.27
22.5	4,013,037	11,724	0.0029	0.9971	94.96
23.5	3,993,949	28,141	0.0070	0.9930	94.68
24.5	3,653,672	3,014	0.0008	0.9992	94.02
25.5	3,070,393	656	0.0002	0.9998	93.94
26.5	2,437,277	1,973	0.0008	0.9992	93.92
27.5	2,253,875	12,586	0.0056	0.9944	93.84
28.5	2,206,292	18,059	0.0082	0.9918	93.32
29.5	2,182,025	3,739	0.0017	0.9983	92.56
30.5	2,173,582	35,858	0.0165	0.9835	92.40
31.5	2,049,270	3,702	0.0018	0.9982	90.87
32.5	2,047,328	32,489	0.0159	0.9841	90.71
33.5	2,014,866	10,692	0.0053	0.9947	89.27
34.5	1,993,065	23,188	0.0116	0.9884	88.80
35.5	1,876,785	29,963	0.0160	0.9840	87.76
36.5	1,609,849	17,413	0.0108	0.9892	86.36
37.5	1,592,912	15,787	0.0099	0.9901	85.43
38.5	1,565,035	26,636	0.0170	0.9830	84.58

ROCKLAND ELECTRIC COMPANY

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1902-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,538,837	9,912	0.0064	0.9936	83.14
40.5	1,409,825	13,082	0.0093	0.9907	82.61
41.5	1,390,311	39,797	0.0286	0.9714	81.84
42.5	1,216,183	22,872	0.0188	0.9812	79.50
43.5	907,452	7,851	0.0087	0.9913	78.00
44.5	726,139	7,515	0.0103	0.9897	77.33
45.5	641,222	30,117	0.0470	0.9530	76.53
46.5	611,121	11,772	0.0193	0.9807	72.93
47.5	577,174	12,298	0.0213	0.9787	71.53
48.5	489,996	25,998	0.0531	0.9469	70.00
49.5	467,316	33,367	0.0714	0.9286	66.29
50.5	433,160	71,685	0.1655	0.8345	61.56
51.5	359,259	1,658	0.0046	0.9954	51.37
52.5	244,857	261	0.0011	0.9989	51.13
53.5	231,160	3,992	0.0173	0.9827	51.08
54.5	214,571	19,948	0.0930	0.9070	50.19
55.5	183,468	1,034	0.0056	0.9944	45.53
56.5	178,141	7,001	0.0393	0.9607	45.27
57.5	171,099	3,695	0.0216	0.9784	43.49
58.5	166,954	698	0.0042	0.9958	42.55
59.5	165,533	4,639	0.0280	0.9720	42.38
60.5	146,239	352	0.0024	0.9976	41.19
61.5	105,235	1,305	0.0124	0.9876	41.09
62.5	103,824	3,348	0.0322	0.9678	40.58
63.5	99,608	5,454	0.0548	0.9452	39.27
64.5	84,939	4,913	0.0578	0.9422	37.12
65.5	66,684	2,916	0.0437	0.9563	34.97
66.5	61,872	3,893	0.0629	0.9371	33.44
67.5	55,884	30	0.0005	0.9995	31.34
68.5	55,854	248	0.0044	0.9956	31.32
69.5	55,606	708	0.0127	0.9873	31.18
70.5	53,720	1,790	0.0333	0.9667	30.79
71.5	51,930	12,120	0.2334	0.7666	29.76
72.5	39,682	119	0.0030	0.9970	22.81
73.5	39,563	3,141	0.0794	0.9206	22.75
74.5	36,422	8,754	0.2404	0.7596	20.94
75.5	26,578	1,219	0.0459	0.9541	15.91
76.5	25,359	1,376	0.0543	0.9457	15.18
77.5	23,983	1,122	0.0468	0.9532	14.35
78.5	22,861	807	0.0353	0.9647	13.68

ROCKLAND ELECTRIC COMPANY

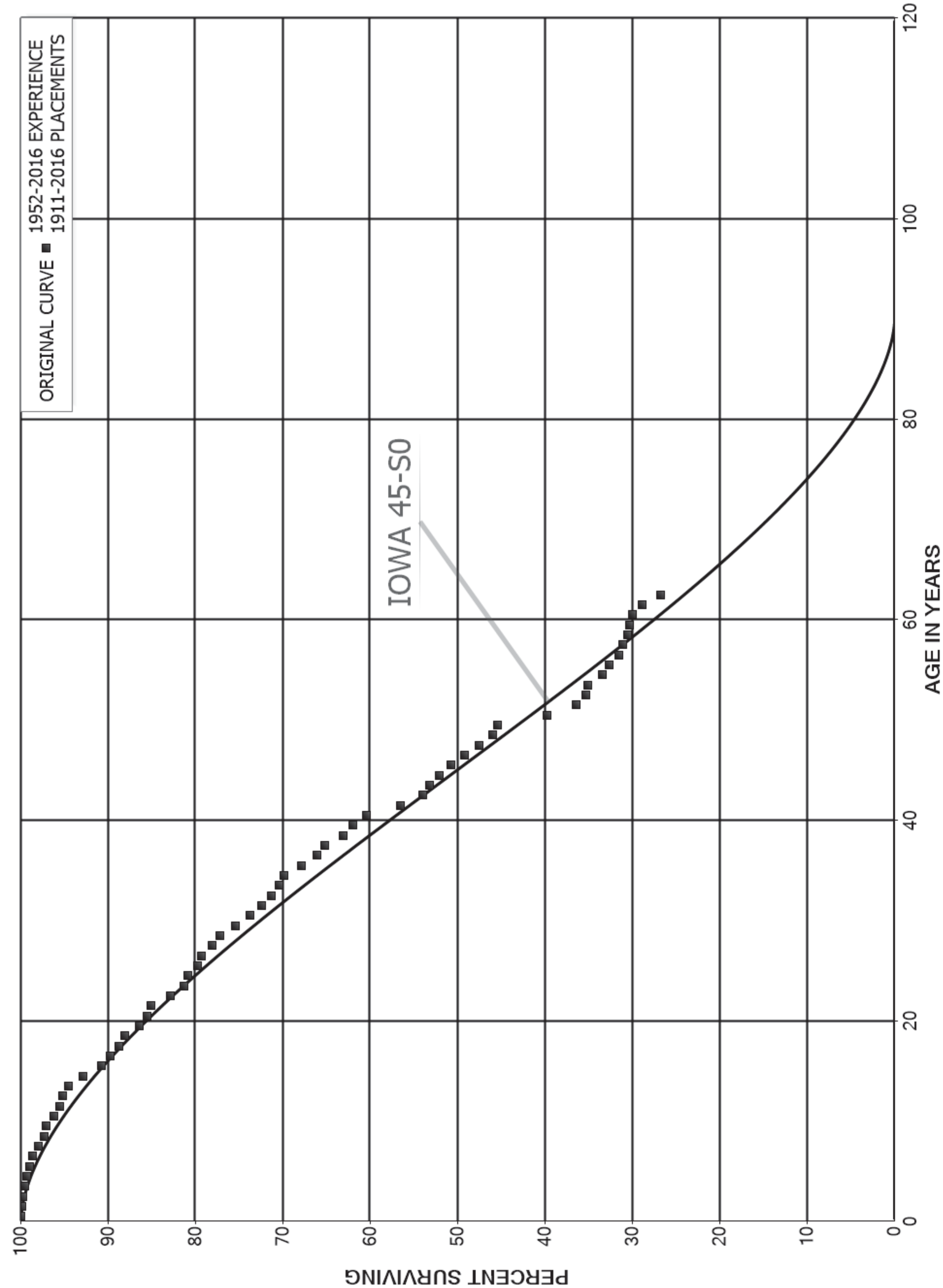
ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1902-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	21,959	452	0.0206	0.9794	13.20
80.5	21,507	593	0.0276	0.9724	12.93
81.5	20,914	1,369	0.0655	0.9345	12.57
82.5	19,545	4,701	0.2405	0.7595	11.75
83.5	14,844	1,099	0.0740	0.9260	8.92
84.5	13,547	16	0.0012	0.9988	8.26
85.5	13,529		0.0000	1.0000	8.25
86.5	13,205		0.0000	1.0000	8.25
87.5	7,868		0.0000	1.0000	8.25
88.5	7,599		0.0000	1.0000	8.25
89.5	4,889		0.0000	1.0000	8.25
90.5	4,481		0.0000	1.0000	8.25
91.5	4,481		0.0000	1.0000	8.25
92.5	4,481		0.0000	1.0000	8.25
93.5	2,750		0.0000	1.0000	8.25
94.5					8.25

ROCKLAND ELECTRIC COMPANY
ACCOUNT 362.00 STATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



ROCKLAND ELECTRIC COMPANY

ACCOUNT 362.00 STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1911-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	262,589,038	4,701	0.0000	1.0000	100.00
0.5	225,085,951	357,761	0.0016	0.9984	100.00
1.5	221,181,802	311,316	0.0014	0.9986	99.84
2.5	200,036,825	319,576	0.0016	0.9984	99.70
3.5	193,079,011	488,390	0.0025	0.9975	99.54
4.5	171,848,926	569,427	0.0033	0.9967	99.29
5.5	164,486,274	605,556	0.0037	0.9963	98.96
6.5	160,662,409	1,045,954	0.0065	0.9935	98.59
7.5	154,427,046	1,051,532	0.0068	0.9932	97.95
8.5	143,346,676	343,480	0.0024	0.9976	97.29
9.5	133,178,473	1,148,087	0.0086	0.9914	97.05
10.5	125,734,661	959,251	0.0076	0.9924	96.22
11.5	114,477,746	384,285	0.0034	0.9966	95.48
12.5	98,284,464	653,871	0.0067	0.9933	95.16
13.5	88,520,080	1,587,014	0.0179	0.9821	94.53
14.5	77,110,317	1,740,922	0.0226	0.9774	92.83
15.5	74,703,432	858,219	0.0115	0.9885	90.74
16.5	72,052,696	821,412	0.0114	0.9886	89.70
17.5	68,642,307	465,699	0.0068	0.9932	88.67
18.5	67,183,371	1,289,444	0.0192	0.9808	88.07
19.5	60,870,754	587,979	0.0097	0.9903	86.38
20.5	58,460,287	335,360	0.0057	0.9943	85.55
21.5	53,617,683	1,422,880	0.0265	0.9735	85.06
22.5	51,440,635	954,038	0.0185	0.9815	82.80
23.5	49,741,901	236,895	0.0048	0.9952	81.26
24.5	45,676,289	679,865	0.0149	0.9851	80.88
25.5	40,840,037	222,344	0.0054	0.9946	79.67
26.5	34,456,466	500,017	0.0145	0.9855	79.24
27.5	31,667,223	374,343	0.0118	0.9882	78.09
28.5	29,550,327	688,550	0.0233	0.9767	77.17
29.5	28,304,252	610,696	0.0216	0.9784	75.37
30.5	26,794,433	484,987	0.0181	0.9819	73.74
31.5	25,781,342	382,921	0.0149	0.9851	72.41
32.5	25,266,702	343,278	0.0136	0.9864	71.33
33.5	24,843,495	182,458	0.0073	0.9927	70.36
34.5	24,419,386	698,553	0.0286	0.9714	69.84
35.5	21,184,948	566,743	0.0268	0.9732	67.85
36.5	17,460,501	223,293	0.0128	0.9872	66.03
37.5	17,185,393	552,437	0.0321	0.9679	65.19
38.5	16,205,463	293,923	0.0181	0.9819	63.09

ROCKLAND ELECTRIC COMPANY

ACCOUNT 362.00 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1911-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	15,762,869	384,769	0.0244	0.9756	61.95
40.5	13,293,381	867,162	0.0652	0.9348	60.44
41.5	11,976,584	541,258	0.0452	0.9548	56.49
42.5	9,585,893	126,236	0.0132	0.9868	53.94
43.5	7,320,849	161,500	0.0221	0.9779	53.23
44.5	6,131,438	152,702	0.0249	0.9751	52.06
45.5	4,584,096	138,732	0.0303	0.9697	50.76
46.5	4,286,645	152,356	0.0355	0.9645	49.22
47.5	3,675,339	119,041	0.0324	0.9676	47.47
48.5	3,095,690	38,588	0.0125	0.9875	45.94
49.5	2,805,394	345,880	0.1233	0.8767	45.36
50.5	2,435,330	205,138	0.0842	0.9158	39.77
51.5	2,205,137	67,869	0.0308	0.9692	36.42
52.5	1,844,081	13,211	0.0072	0.9928	35.30
53.5	1,714,847	80,574	0.0470	0.9530	35.05
54.5	1,444,065	34,230	0.0237	0.9763	33.40
55.5	1,317,145	43,667	0.0332	0.9668	32.61
56.5	1,268,472	17,391	0.0137	0.9863	31.53
57.5	903,217	17,192	0.0190	0.9810	31.09
58.5	881,507	6,579	0.0075	0.9925	30.50
59.5	815,743	7,312	0.0090	0.9910	30.28
60.5	778,250	30,088	0.0387	0.9613	30.00
61.5	734,506	55,126	0.0751	0.9249	28.84
62.5	471,662	10,152	0.0215	0.9785	26.68
63.5	443,186	23,652	0.0534	0.9466	26.10
64.5	375,424	19,543	0.0521	0.9479	24.71
65.5	328,514	9,661	0.0294	0.9706	23.43
66.5	277,389	2,460	0.0089	0.9911	22.74
67.5	269,565	4,846	0.0180	0.9820	22.53
68.5	264,719	11,094	0.0419	0.9581	22.13
69.5	252,661	342	0.0014	0.9986	21.20
70.5	246,720	1,396	0.0057	0.9943	21.17
71.5	244,716	7,390	0.0302	0.9698	21.05
72.5	237,143	4,130	0.0174	0.9826	20.42
73.5	233,013	63,785	0.2737	0.7263	20.06
74.5	168,139	4,260	0.0253	0.9747	14.57
75.5	163,193	22,729	0.1393	0.8607	14.20
76.5	140,239	151	0.0011	0.9989	12.22
77.5	137,921	1,146	0.0083	0.9917	12.21
78.5	136,775	207	0.0015	0.9985	12.11

ROCKLAND ELECTRIC COMPANY

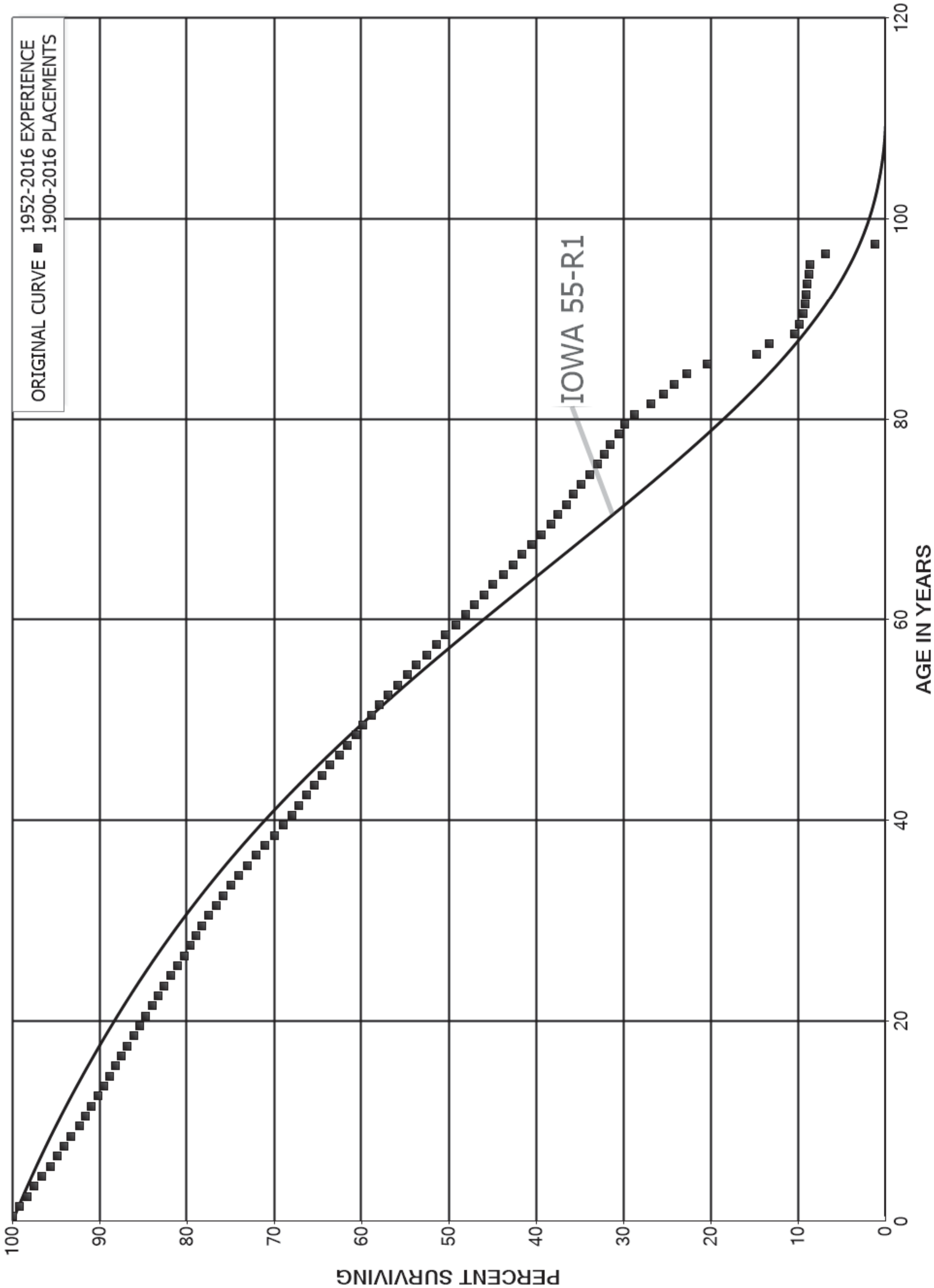
ACCOUNT 362.00 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1911-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	136,300	13	0.0001	0.9999	12.09
80.5	136,287	4,271	0.0313	0.9687	12.09
81.5	131,930		0.0000	1.0000	11.71
82.5	131,930	1,768	0.0134	0.9866	11.71
83.5	130,163	3,908	0.0300	0.9700	11.55
84.5	126,223		0.0000	1.0000	11.21
85.5	125,727		0.0000	1.0000	11.21
86.5	111,989	1,228	0.0110	0.9890	11.21
87.5	98,693		0.0000	1.0000	11.08
88.5	85,570		0.0000	1.0000	11.08
89.5	1,587		0.0000	1.0000	11.08
90.5	1,587		0.0000	1.0000	11.08
91.5	1,587		0.0000	1.0000	11.08
92.5	182		0.0000	1.0000	11.08
93.5	134		0.0000	1.0000	11.08
94.5	134		0.0000	1.0000	11.08
95.5	134		0.0000	1.0000	11.08
96.5	134		0.0000	1.0000	11.08
97.5	134		0.0000	1.0000	11.08
98.5	134		0.0000	1.0000	11.08
99.5	134		0.0000	1.0000	11.08
100.5	134		0.0000	1.0000	11.08
101.5	134		0.0000	1.0000	11.08
102.5					11.08

ROCKLAND ELECTRIC COMPANY
ACCOUNT 364.00 POLES, TOWERS AND FIXTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES



ROCKLAND ELECTRIC COMPANY

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1900-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	243,103,192	111,537	0.0005	0.9995	100.00
0.5	235,146,684	1,848,771	0.0079	0.9921	99.95
1.5	222,522,388	2,040,759	0.0092	0.9908	99.17
2.5	211,288,093	1,646,620	0.0078	0.9922	98.26
3.5	198,219,175	1,724,608	0.0087	0.9913	97.49
4.5	170,565,246	1,760,371	0.0103	0.9897	96.64
5.5	160,927,384	1,332,423	0.0083	0.9917	95.65
6.5	151,023,205	1,256,015	0.0083	0.9917	94.86
7.5	142,159,196	1,217,946	0.0086	0.9914	94.07
8.5	131,913,585	1,342,954	0.0102	0.9898	93.26
9.5	124,106,201	909,071	0.0073	0.9927	92.31
10.5	117,379,927	891,342	0.0076	0.9924	91.63
11.5	110,605,921	869,576	0.0079	0.9921	90.94
12.5	105,370,438	891,123	0.0085	0.9915	90.22
13.5	101,084,132	750,226	0.0074	0.9926	89.46
14.5	97,109,304	692,786	0.0071	0.9929	88.80
15.5	93,321,565	723,092	0.0077	0.9923	88.16
16.5	89,978,155	672,080	0.0075	0.9925	87.48
17.5	85,031,562	712,389	0.0084	0.9916	86.83
18.5	82,062,024	663,399	0.0081	0.9919	86.10
19.5	79,255,550	661,490	0.0083	0.9917	85.40
20.5	76,355,680	626,519	0.0082	0.9918	84.69
21.5	72,612,314	574,615	0.0079	0.9921	84.00
22.5	69,681,909	637,763	0.0092	0.9908	83.33
23.5	66,099,990	587,424	0.0089	0.9911	82.57
24.5	62,761,862	553,144	0.0088	0.9912	81.83
25.5	59,135,729	578,578	0.0098	0.9902	81.11
26.5	53,925,854	445,956	0.0083	0.9917	80.32
27.5	48,650,426	447,431	0.0092	0.9908	79.66
28.5	46,042,725	404,231	0.0088	0.9912	78.92
29.5	43,211,939	416,746	0.0096	0.9904	78.23
30.5	40,927,760	427,967	0.0105	0.9895	77.48
31.5	39,055,602	425,097	0.0109	0.9891	76.67
32.5	37,087,650	425,411	0.0115	0.9885	75.83
33.5	35,160,937	408,867	0.0116	0.9884	74.96
34.5	33,423,127	439,524	0.0132	0.9868	74.09
35.5	31,122,592	459,565	0.0148	0.9852	73.12
36.5	29,431,687	412,301	0.0140	0.9860	72.04
37.5	27,738,511	408,306	0.0147	0.9853	71.03
38.5	26,009,869	362,644	0.0139	0.9861	69.98

ROCKLAND ELECTRIC COMPANY

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	24,283,384	355,293	0.0146	0.9854	69.01
40.5	22,658,273	289,836	0.0128	0.9872	68.00
41.5	20,478,962	269,698	0.0132	0.9868	67.13
42.5	17,385,225	214,433	0.0123	0.9877	66.24
43.5	13,972,593	188,106	0.0135	0.9865	65.42
44.5	11,411,077	157,863	0.0138	0.9862	64.54
45.5	9,724,225	175,958	0.0181	0.9819	63.65
46.5	8,401,467	122,687	0.0146	0.9854	62.50
47.5	7,532,925	113,732	0.0151	0.9849	61.59
48.5	6,668,852	93,224	0.0140	0.9860	60.66
49.5	6,026,662	96,170	0.0160	0.9840	59.81
50.5	5,264,906	79,508	0.0151	0.9849	58.85
51.5	4,682,473	79,525	0.0170	0.9830	57.97
52.5	4,027,567	77,679	0.0193	0.9807	56.98
53.5	3,548,374	72,425	0.0204	0.9796	55.88
54.5	3,088,611	57,020	0.0185	0.9815	54.74
55.5	2,713,767	60,765	0.0224	0.9776	53.73
56.5	2,341,510	48,367	0.0207	0.9793	52.53
57.5	2,014,896	42,738	0.0212	0.9788	51.44
58.5	1,788,127	43,658	0.0244	0.9756	50.35
59.5	1,529,643	31,933	0.0209	0.9791	49.12
60.5	1,288,272	28,742	0.0223	0.9777	48.10
61.5	1,112,342	26,722	0.0240	0.9760	47.02
62.5	958,151	20,633	0.0215	0.9785	45.89
63.5	773,075	20,644	0.0267	0.9733	44.91
64.5	665,380	16,403	0.0247	0.9753	43.71
65.5	563,486	13,173	0.0234	0.9766	42.63
66.5	443,377	12,191	0.0275	0.9725	41.63
67.5	380,775	10,771	0.0283	0.9717	40.49
68.5	330,271	8,951	0.0271	0.9729	39.34
69.5	297,150	5,960	0.0201	0.9799	38.28
70.5	273,728	7,361	0.0269	0.9731	37.51
71.5	256,334	5,298	0.0207	0.9793	36.50
72.5	238,242	6,017	0.0253	0.9747	35.75
73.5	219,997	6,388	0.0290	0.9710	34.84
74.5	197,529	5,241	0.0265	0.9735	33.83
75.5	177,265	3,846	0.0217	0.9783	32.93
76.5	157,230	3,505	0.0223	0.9777	32.22
77.5	138,583	4,400	0.0318	0.9682	31.50
78.5	123,701	2,864	0.0232	0.9768	30.50

ROCKLAND ELECTRIC COMPANY

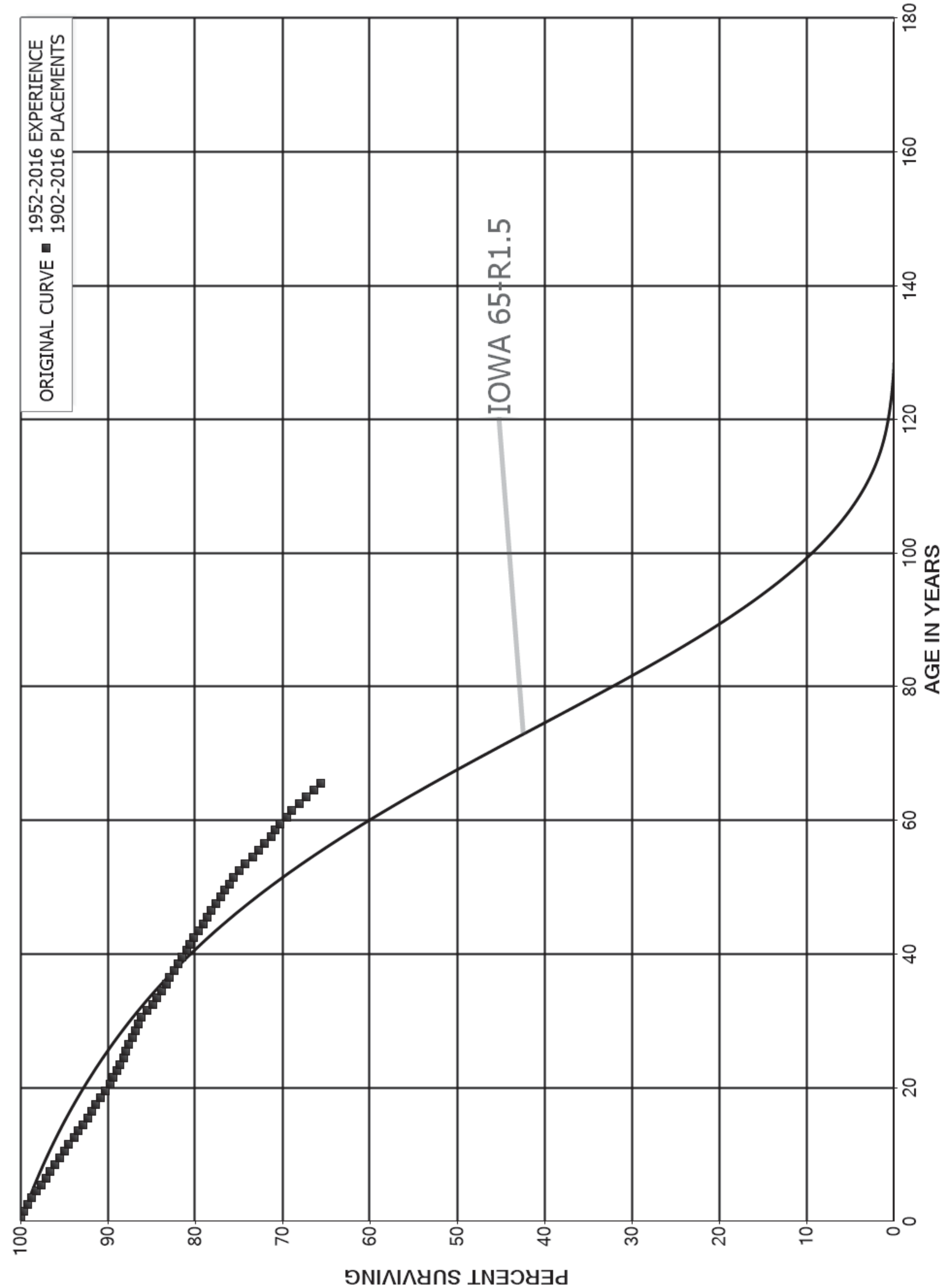
ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	110,194	3,777	0.0343	0.9657	29.79
80.5	95,983	6,428	0.0670	0.9330	28.77
81.5	82,593	4,544	0.0550	0.9450	26.85
82.5	72,637	3,535	0.0487	0.9513	25.37
83.5	63,461	3,764	0.0593	0.9407	24.13
84.5	54,311	5,632	0.1037	0.8963	22.70
85.5	45,519	12,514	0.2749	0.7251	20.35
86.5	30,370	2,951	0.0972	0.9028	14.75
87.5	19,932	4,382	0.2198	0.7802	13.32
88.5	12,879	666	0.0517	0.9483	10.39
89.5	8,579	359	0.0418	0.9582	9.85
90.5	8,049	260	0.0323	0.9677	9.44
91.5	7,492	88	0.0117	0.9883	9.14
92.5	7,404	61	0.0082	0.9918	9.03
93.5	7,232	150	0.0208	0.9792	8.96
94.5	6,972	112	0.0160	0.9840	8.77
95.5	6,860	1,424	0.2076	0.7924	8.63
96.5	5,400	4,452	0.8244	0.1756	6.84
97.5	948	428	0.4517	0.5483	1.20
98.5	520	77	0.1489	0.8511	0.66
99.5	422	56	0.1332	0.8668	0.56
100.5	355	24	0.0687	0.9313	0.49
101.5	331	15	0.0454	0.9546	0.45
102.5	254	21	0.0842	0.9158	0.43
103.5	209	6	0.0283	0.9717	0.40
104.5	203	54	0.2659	0.7341	0.38
105.5	149	21	0.1402	0.8598	0.28
106.5	128	31	0.2407	0.7593	0.24
107.5	97	66	0.6767	0.3233	0.18
108.5	32	17	0.5238	0.4762	0.06
109.5	15		0.0000	1.0000	0.03
110.5	15		0.0000	1.0000	0.03
111.5					0.03

ROCKLAND ELECTRIC COMPANY
ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



ROCKLAND ELECTRIC COMPANY

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1902-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	250,437,154	45,193	0.0002	0.9998	100.00
0.5	240,022,685	793,982	0.0033	0.9967	99.98
1.5	225,763,802	1,018,970	0.0045	0.9955	99.65
2.5	213,864,994	1,139,763	0.0053	0.9947	99.20
3.5	200,902,021	951,906	0.0047	0.9953	98.67
4.5	188,095,231	1,116,755	0.0059	0.9941	98.21
5.5	177,849,361	952,887	0.0054	0.9946	97.62
6.5	164,853,236	879,194	0.0053	0.9947	97.10
7.5	154,435,714	872,901	0.0057	0.9943	96.58
8.5	142,365,436	791,830	0.0056	0.9944	96.04
9.5	134,483,945	803,151	0.0060	0.9940	95.50
10.5	127,173,214	619,772	0.0049	0.9951	94.93
11.5	120,191,238	760,365	0.0063	0.9937	94.47
12.5	114,382,693	622,898	0.0054	0.9946	93.87
13.5	109,680,814	570,583	0.0052	0.9948	93.36
14.5	105,229,473	724,246	0.0069	0.9931	92.87
15.5	100,656,620	484,718	0.0048	0.9952	92.23
16.5	96,284,041	429,844	0.0045	0.9955	91.79
17.5	89,882,224	524,048	0.0058	0.9942	91.38
18.5	86,153,719	565,280	0.0066	0.9934	90.85
19.5	83,006,980	449,042	0.0054	0.9946	90.25
20.5	79,418,747	336,633	0.0042	0.9958	89.76
21.5	74,614,482	341,920	0.0046	0.9954	89.38
22.5	70,410,780	272,130	0.0039	0.9961	88.97
23.5	66,343,882	301,497	0.0045	0.9955	88.63
24.5	62,311,110	200,595	0.0032	0.9968	88.23
25.5	58,907,639	221,168	0.0038	0.9962	87.94
26.5	53,835,667	250,011	0.0046	0.9954	87.61
27.5	48,218,894	185,099	0.0038	0.9962	87.21
28.5	46,340,122	188,025	0.0041	0.9959	86.87
29.5	44,203,753	175,082	0.0040	0.9960	86.52
30.5	42,315,967	352,543	0.0083	0.9917	86.18
31.5	40,656,251	276,447	0.0068	0.9932	85.46
32.5	39,133,277	238,025	0.0061	0.9939	84.88
33.5	37,598,514	225,940	0.0060	0.9940	84.36
34.5	36,008,716	237,671	0.0066	0.9934	83.85
35.5	33,826,703	148,626	0.0044	0.9956	83.30
36.5	32,412,288	198,545	0.0061	0.9939	82.93
37.5	30,918,472	161,799	0.0052	0.9948	82.43
38.5	29,525,399	181,653	0.0062	0.9938	81.99

ROCKLAND ELECTRIC COMPANY

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1902-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	27,763,008	166,486	0.0060	0.9940	81.49
40.5	26,279,724	141,489	0.0054	0.9946	81.00
41.5	24,206,583	115,175	0.0048	0.9952	80.57
42.5	21,044,642	162,692	0.0077	0.9923	80.18
43.5	17,661,224	121,441	0.0069	0.9931	79.56
44.5	14,743,501	71,209	0.0048	0.9952	79.02
45.5	12,872,570	79,622	0.0062	0.9938	78.63
46.5	10,970,316	74,568	0.0068	0.9932	78.15
47.5	9,982,484	71,563	0.0072	0.9928	77.62
48.5	8,833,960	56,449	0.0064	0.9936	77.06
49.5	8,161,415	55,211	0.0068	0.9932	76.57
50.5	7,121,970	45,578	0.0064	0.9936	76.05
51.5	6,459,240	50,304	0.0078	0.9922	75.56
52.5	5,748,819	52,754	0.0092	0.9908	74.97
53.5	5,177,685	64,834	0.0125	0.9875	74.29
54.5	4,597,979	40,094	0.0087	0.9913	73.36
55.5	4,103,861	38,577	0.0094	0.9906	72.72
56.5	3,604,700	36,895	0.0102	0.9898	72.03
57.5	3,188,715	22,660	0.0071	0.9929	71.30
58.5	2,799,204	21,257	0.0076	0.9924	70.79
59.5	2,411,934	26,731	0.0111	0.9889	70.25
60.5	2,015,203	15,720	0.0078	0.9922	69.47
61.5	1,765,752	22,117	0.0125	0.9875	68.93
62.5	1,547,966	17,044	0.0110	0.9890	68.07
63.5	1,172,368	15,972	0.0136	0.9864	67.32
64.5	1,080,449	13,102	0.0121	0.9879	66.40
65.5	944,480	10,452	0.0111	0.9889	65.60
66.5	804,693	13,778	0.0171	0.9829	64.87
67.5	715,608	13,921	0.0195	0.9805	63.76
68.5	635,593	6,991	0.0110	0.9890	62.52
69.5	581,424	8,354	0.0144	0.9856	61.83
70.5	544,543	6,982	0.0128	0.9872	60.94
71.5	527,601	6,887	0.0131	0.9869	60.16
72.5	517,011	8,542	0.0165	0.9835	59.38
73.5	506,675	5,144	0.0102	0.9898	58.39
74.5	483,879	2,939	0.0061	0.9939	57.80
75.5	458,395	4,419	0.0096	0.9904	57.45
76.5	431,495	3,267	0.0076	0.9924	56.90
77.5	399,765	4,307	0.0108	0.9892	56.47
78.5	369,694	3,038	0.0082	0.9918	55.86

ROCKLAND ELECTRIC COMPANY

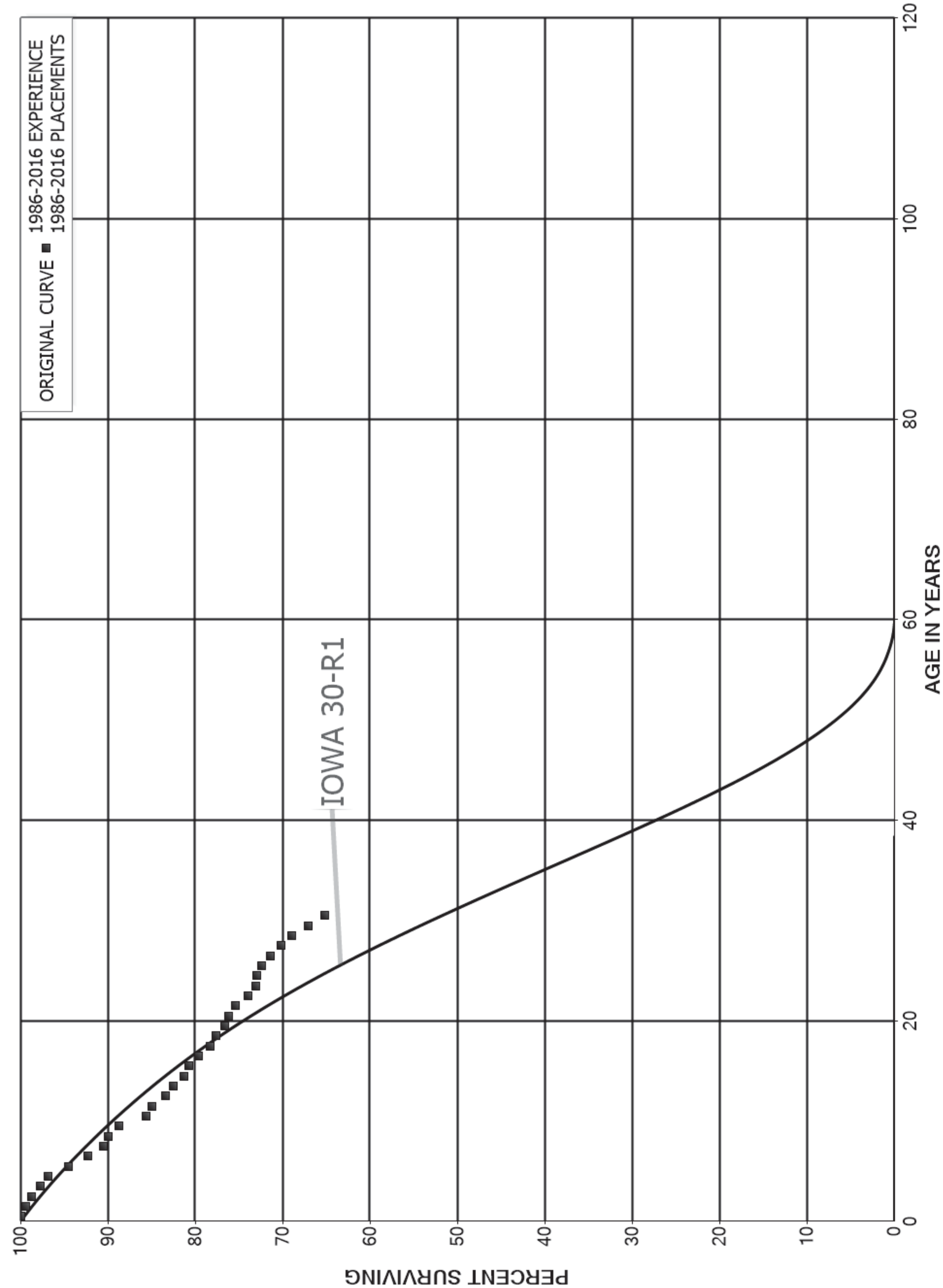
ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1902-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	332,358	5,198	0.0156	0.9844	55.40
80.5	301,874	4,271	0.0141	0.9859	54.53
81.5	285,198	2,940	0.0103	0.9897	53.76
82.5	268,784	1,992	0.0074	0.9926	53.21
83.5	250,105	3,446	0.0138	0.9862	52.81
84.5	227,098	1,898	0.0084	0.9916	52.09
85.5	207,255	1,555	0.0075	0.9925	51.65
86.5	173,861	1,462	0.0084	0.9916	51.26
87.5	129,304	734	0.0057	0.9943	50.83
88.5	104,700	920	0.0088	0.9912	50.54
89.5	74,634	945	0.0127	0.9873	50.10
90.5	54,266	506	0.0093	0.9907	49.46
91.5	38,328	163	0.0043	0.9957	49.00
92.5	32,816	54	0.0017	0.9983	48.79
93.5	15,031	40	0.0027	0.9973	48.71
94.5	11,099	125	0.0112	0.9888	48.58
95.5	10,063	76	0.0075	0.9925	48.04
96.5	9,677	90	0.0093	0.9907	47.68
97.5	9,355	141	0.0151	0.9849	47.23
98.5	7,690	27	0.0036	0.9964	46.52
99.5	6,515	126	0.0193	0.9807	46.36
100.5	5,851	83	0.0141	0.9859	45.46
101.5	5,452	34	0.0063	0.9937	44.82
102.5	5,062	35	0.0069	0.9931	44.54
103.5	4,384	5	0.0012	0.9988	44.23
104.5	3,704	67	0.0180	0.9820	44.18
105.5	3,508	3	0.0009	0.9991	43.39
106.5	2,525		0.0000	1.0000	43.35
107.5	2,117	95	0.0450	0.9550	43.35
108.5	1,897	7	0.0039	0.9961	41.40
109.5	1,890	105	0.0557	0.9443	41.24
110.5	1,785	368	0.2064	0.7936	38.94
111.5	1,416		0.0000	1.0000	30.90
112.5	1,416		0.0000	1.0000	30.90
113.5	1,416		0.0000	1.0000	30.90
114.5					30.90

ROCKLAND ELECTRIC COMPANY
ACCOUNT 365.10 OVERHEAD CONDUCTORS AND DEVICES - CAPACITORS
ORIGINAL AND SMOOTH SURVIVOR CURVES



ROCKLAND ELECTRIC COMPANY

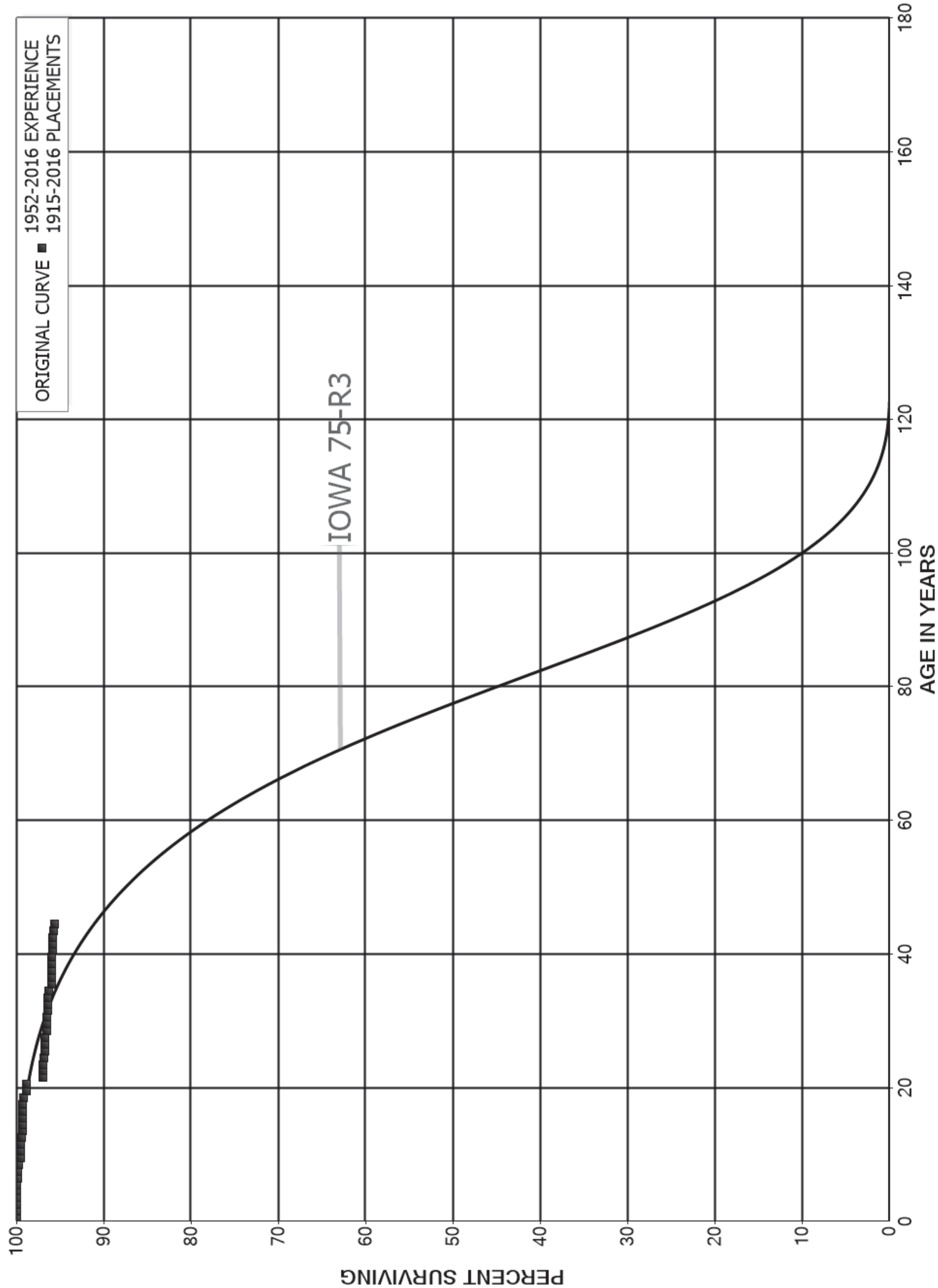
ACCOUNT 365.10 OVERHEAD CONDUCTORS AND DEVICES - CAPACITORS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1986-2016 EXPERIENCE BAND 1986-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	6,810,950		0.0000	1.0000	100.00
0.5	6,431,369	39,253	0.0061	0.9939	100.00
1.5	5,990,824	38,007	0.0063	0.9937	99.39
2.5	5,789,966	58,773	0.0102	0.9898	98.76
3.5	5,319,328	49,382	0.0093	0.9907	97.76
4.5	4,653,267	115,220	0.0248	0.9752	96.85
5.5	4,289,568	99,682	0.0232	0.9768	94.45
6.5	3,724,172	68,958	0.0185	0.9815	92.26
7.5	3,410,161	21,860	0.0064	0.9936	90.55
8.5	3,033,214	41,698	0.0137	0.9863	89.97
9.5	2,855,907	98,598	0.0345	0.9655	88.73
10.5	2,642,706	22,583	0.0085	0.9915	85.67
11.5	2,520,916	45,639	0.0181	0.9819	84.94
12.5	2,438,083	26,370	0.0108	0.9892	83.40
13.5	2,360,255	35,991	0.0152	0.9848	82.50
14.5	2,220,669	15,064	0.0068	0.9932	81.24
15.5	2,177,608	28,916	0.0133	0.9867	80.69
16.5	2,119,878	36,156	0.0171	0.9829	79.62
17.5	2,060,922	15,593	0.0076	0.9924	78.26
18.5	1,942,516	26,418	0.0136	0.9864	77.67
19.5	1,907,606	10,583	0.0055	0.9945	76.61
20.5	1,845,226	19,632	0.0106	0.9894	76.18
21.5	1,811,401	34,959	0.0193	0.9807	75.37
22.5	1,734,973	20,865	0.0120	0.9880	73.92
23.5	1,652,312	2,984	0.0018	0.9982	73.03
24.5	1,589,065	10,313	0.0065	0.9935	72.90
25.5	1,217,615	17,807	0.0146	0.9854	72.42
26.5	1,028,785	17,237	0.0168	0.9832	71.37
27.5	678,339	12,217	0.0180	0.9820	70.17
28.5	521,666	13,743	0.0263	0.9737	68.91
29.5	507,923	14,834	0.0292	0.9708	67.09
30.5					65.13

ROCKLAND ELECTRIC COMPANY
ACCOUNT 366.00 UNDERGROUND CONDUIT
ORIGINAL AND SMOOTH SURVIVOR CURVES



ROCKLAND ELECTRIC COMPANY

ACCOUNT 366.00 UNDERGROUND CONDUIT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1915-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	44,939,290		0.0000	1.0000	100.00
0.5	41,521,626	8,116	0.0002	0.9998	100.00
1.5	40,247,348	16,202	0.0004	0.9996	99.98
2.5	36,441,825	8,272	0.0002	0.9998	99.94
3.5	35,685,844	3,952	0.0001	0.9999	99.92
4.5	34,715,956	2,556	0.0001	0.9999	99.91
5.5	32,480,997	12,036	0.0004	0.9996	99.90
6.5	31,639,668	23,426	0.0007	0.9993	99.86
7.5	30,192,673	21,394	0.0007	0.9993	99.79
8.5	28,002,553	46,933	0.0017	0.9983	99.72
9.5	26,663,371	10,781	0.0004	0.9996	99.55
10.5	25,653,400	15,126	0.0006	0.9994	99.51
11.5	25,009,430	18,851	0.0008	0.9992	99.45
12.5	23,882,834	12,659	0.0005	0.9995	99.38
13.5	21,309,068	6,376	0.0003	0.9997	99.32
14.5	20,820,559	1,143	0.0001	0.9999	99.29
15.5	20,569,200	4,808	0.0002	0.9998	99.29
16.5	20,119,446	829	0.0000	1.0000	99.27
17.5	19,612,859	12,377	0.0006	0.9994	99.26
18.5	18,451,613	58,050	0.0031	0.9969	99.20
19.5	18,162,512	8,561	0.0005	0.9995	98.89
20.5	17,726,177	343,789	0.0194	0.9806	98.84
21.5	16,556,427	1,520	0.0001	0.9999	96.92
22.5	16,195,244	1,020	0.0001	0.9999	96.91
23.5	15,338,371	4,498	0.0003	0.9997	96.91
24.5	14,441,064	17,871	0.0012	0.9988	96.88
25.5	10,922,636	452	0.0000	1.0000	96.76
26.5	9,527,897	1,465	0.0002	0.9998	96.76
27.5	8,545,979	20,459	0.0024	0.9976	96.74
28.5	8,029,508	464	0.0001	0.9999	96.51
29.5	8,029,448	3,677	0.0005	0.9995	96.50
30.5	7,227,307	1,019	0.0001	0.9999	96.46
31.5	6,778,541	2,681	0.0004	0.9996	96.45
32.5	6,458,416	4,517	0.0007	0.9993	96.41
33.5	6,124,992	322	0.0001	0.9999	96.34
34.5	5,795,630	24,122	0.0042	0.9958	96.34
35.5	5,177,725	140	0.0000	1.0000	95.93
36.5	4,878,585	582	0.0001	0.9999	95.93
37.5	4,680,551		0.0000	1.0000	95.92
38.5	4,397,025	148	0.0000	1.0000	95.92

ROCKLAND ELECTRIC COMPANY

ACCOUNT 366.00 UNDERGROUND CONDUIT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1915-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	4,081,813	3,613	0.0009	0.9991	95.92
40.5	2,223,528	1	0.0000	1.0000	95.83
41.5	2,142,979	129	0.0001	0.9999	95.83
42.5	1,758,653	1,666	0.0009	0.9991	95.83
43.5	977,697	824	0.0008	0.9992	95.74
44.5	274,954	815	0.0030	0.9970	95.65
45.5	227,538	1	0.0000	1.0000	95.37
46.5	231,189		0.0000	1.0000	95.37
47.5	143,620		0.0000	1.0000	95.37
48.5	132,741		0.0000	1.0000	95.37
49.5	89,175		0.0000	1.0000	95.37
50.5	80,085		0.0000	1.0000	95.37
51.5	71,395		0.0000	1.0000	95.37
52.5	64,336		0.0000	1.0000	95.37
53.5	61,624		0.0000	1.0000	95.37
54.5	61,624	1	0.0000	1.0000	95.37
55.5	57,519		0.0000	1.0000	95.37
56.5	57,519		0.0000	1.0000	95.37
57.5	54,397		0.0000	1.0000	95.37
58.5	49,625		0.0000	1.0000	95.37
59.5	44,157	21	0.0005	0.9995	95.37
60.5	41,409		0.0000	1.0000	95.32
61.5	23,738		0.0000	1.0000	95.32
62.5	23,361		0.0000	1.0000	95.32
63.5	4,033		0.0000	1.0000	95.32
64.5	2,867		0.0000	1.0000	95.32
65.5	2,867		0.0000	1.0000	95.32
66.5	2,867		0.0000	1.0000	95.32
67.5	1,944		0.0000	1.0000	95.32
68.5	1,944		0.0000	1.0000	95.32
69.5	1,944		0.0000	1.0000	95.32
70.5	1,944		0.0000	1.0000	95.32
71.5	1,944		0.0000	1.0000	95.32
72.5	1,944		0.0000	1.0000	95.32
73.5	1,944		0.0000	1.0000	95.32
74.5	1,944		0.0000	1.0000	95.32
75.5	1,944		0.0000	1.0000	95.32
76.5	1,944		0.0000	1.0000	95.32
77.5	1,944		0.0000	1.0000	95.32
78.5	1,944		0.0000	1.0000	95.32

ROCKLAND ELECTRIC COMPANY

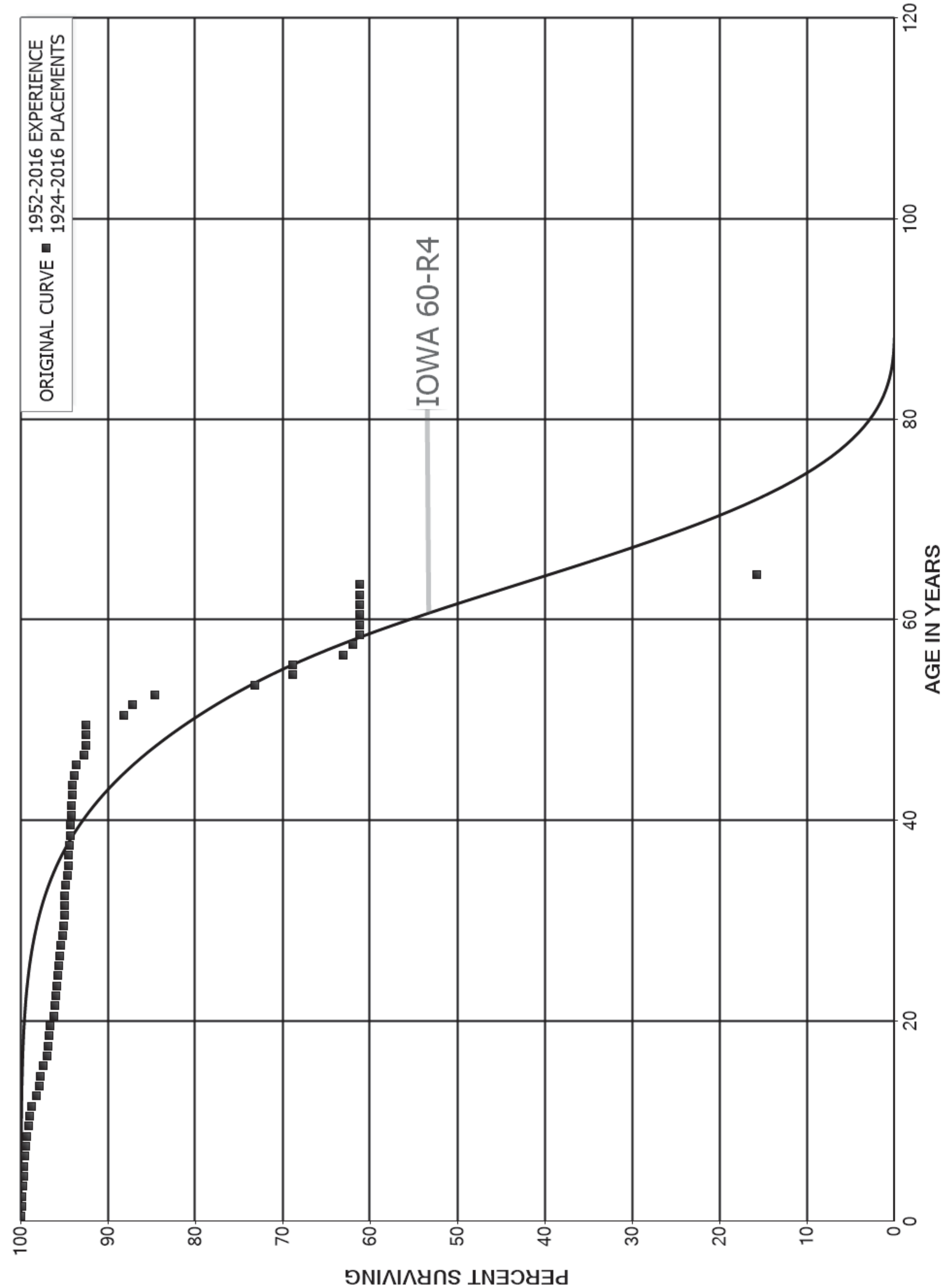
ACCOUNT 366.00 UNDERGROUND CONDUIT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1915-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	1,944		0.0000	1.0000	95.32
80.5	1,944		0.0000	1.0000	95.32
81.5	1,944		0.0000	1.0000	95.32
82.5	1,944		0.0000	1.0000	95.32
83.5	1,944		0.0000	1.0000	95.32
84.5	1,944		0.0000	1.0000	95.32
85.5	1,944		0.0000	1.0000	95.32
86.5	1,944		0.0000	1.0000	95.32
87.5	1,944		0.0000	1.0000	95.32
88.5	1,944		0.0000	1.0000	95.32
89.5	1,944		0.0000	1.0000	95.32
90.5	1,944		0.0000	1.0000	95.32
91.5	1,944		0.0000	1.0000	95.32
92.5	1,944		0.0000	1.0000	95.32
93.5	1,944		0.0000	1.0000	95.32
94.5	1,944		0.0000	1.0000	95.32
95.5	1,944		0.0000	1.0000	95.32
96.5	1,944		0.0000	1.0000	95.32
97.5	1,944		0.0000	1.0000	95.32
98.5	1,944		0.0000	1.0000	95.32
99.5	1,944		0.0000	1.0000	95.32
100.5	1,944		0.0000	1.0000	95.32
101.5					95.32

ROCKLAND ELECTRIC COMPANY
ACCOUNT 367.00 AND 367.10 UNDERGROUND CONDUCTORS AND DEVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



ROCKLAND ELECTRIC COMPANY

ACCOUNT 367.00 AND 367.10 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1924-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	185,438,935	944	0.0000	1.0000	100.00
0.5	169,795,555	212,746	0.0013	0.9987	100.00
1.5	159,781,196	72,146	0.0005	0.9995	99.87
2.5	149,216,851	147,843	0.0010	0.9990	99.83
3.5	142,973,146	95,983	0.0007	0.9993	99.73
4.5	135,737,170	90,283	0.0007	0.9993	99.66
5.5	127,436,477	71,218	0.0006	0.9994	99.60
6.5	120,181,587	147,978	0.0012	0.9988	99.54
7.5	113,834,198	212,780	0.0019	0.9981	99.42
8.5	106,973,342	233,380	0.0022	0.9978	99.23
9.5	101,423,645	91,837	0.0009	0.9991	99.02
10.5	97,204,440	245,515	0.0025	0.9975	98.93
11.5	92,116,564	486,512	0.0053	0.9947	98.68
12.5	83,433,860	231,263	0.0028	0.9972	98.16
13.5	79,493,929	107,887	0.0014	0.9986	97.88
14.5	75,812,824	279,226	0.0037	0.9963	97.75
15.5	72,140,421	339,584	0.0047	0.9953	97.39
16.5	68,042,568	72,816	0.0011	0.9989	96.93
17.5	64,872,904	76,977	0.0012	0.9988	96.83
18.5	61,001,152	79,243	0.0013	0.9987	96.71
19.5	58,498,385	246,254	0.0042	0.9958	96.59
20.5	55,812,146	98,478	0.0018	0.9982	96.18
21.5	52,219,790	50,332	0.0010	0.9990	96.01
22.5	48,651,992	57,790	0.0012	0.9988	95.92
23.5	46,193,632	38,787	0.0008	0.9992	95.81
24.5	42,484,751	40,931	0.0010	0.9990	95.72
25.5	36,267,382	52,024	0.0014	0.9986	95.63
26.5	30,610,985	29,885	0.0010	0.9990	95.50
27.5	23,855,439	57,888	0.0024	0.9976	95.40
28.5	21,960,942	24,580	0.0011	0.9989	95.17
29.5	21,812,810	19,354	0.0009	0.9991	95.06
30.5	18,984,008	11,154	0.0006	0.9994	94.98
31.5	17,707,623	2,990	0.0002	0.9998	94.92
32.5	16,792,086	13,562	0.0008	0.9992	94.91
33.5	15,867,839	44,462	0.0028	0.9972	94.83
34.5	14,244,361	5,618	0.0004	0.9996	94.57
35.5	12,165,356	531	0.0000	1.0000	94.53
36.5	11,475,152	16,399	0.0014	0.9986	94.52
37.5	10,883,364	7,282	0.0007	0.9993	94.39
38.5	9,773,388	4,824	0.0005	0.9995	94.33

ROCKLAND ELECTRIC COMPANY

ACCOUNT 367.00 AND 367.10 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1924-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	8,778,816	6,921	0.0008	0.9992	94.28
40.5	7,129,120	4,109	0.0006	0.9994	94.21
41.5	6,426,074	4,645	0.0007	0.9993	94.15
42.5	4,923,666	2,692	0.0005	0.9995	94.08
43.5	2,731,427	5,640	0.0021	0.9979	94.03
44.5	2,020,780	4,627	0.0023	0.9977	93.84
45.5	1,470,193	14,008	0.0095	0.9905	93.62
46.5	1,045,834	2,677	0.0026	0.9974	92.73
47.5	735,181		0.0000	1.0000	92.49
48.5	520,722		0.0000	1.0000	92.49
49.5	304,792	14,136	0.0464	0.9536	92.49
50.5	134,877	1,529	0.0113	0.9887	88.20
51.5	89,513	2,650	0.0296	0.9704	87.20
52.5	65,512	8,826	0.1347	0.8653	84.62
53.5	43,391	2,571	0.0592	0.9408	73.22
54.5	39,223	3	0.0001	0.9999	68.88
55.5	33,416	2,810	0.0841	0.9159	68.88
56.5	30,178	542	0.0180	0.9820	63.09
57.5	27,572	337	0.0122	0.9878	61.95
58.5	22,021	1	0.0000	1.0000	61.20
59.5	22,020	24	0.0011	0.9989	61.19
60.5	21,995		0.0000	1.0000	61.13
61.5	6,802		0.0000	1.0000	61.13
62.5	6,802		0.0000	1.0000	61.13
63.5	3,875	2,880	0.7433	0.2567	61.13
64.5	995		0.0000	1.0000	15.69
65.5	995		0.0000	1.0000	15.69
66.5	995		0.0000	1.0000	15.69
67.5	995		0.0000	1.0000	15.69
68.5	995		0.0000	1.0000	15.69
69.5	995		0.0000	1.0000	15.69
70.5	995		0.0000	1.0000	15.69
71.5	995		0.0000	1.0000	15.69
72.5	779		0.0000	1.0000	15.69
73.5	779		0.0000	1.0000	15.69
74.5	779		0.0000	1.0000	15.69
75.5	779		0.0000	1.0000	15.69
76.5	779		0.0000	1.0000	15.69
77.5	779		0.0000	1.0000	15.69
78.5	779		0.0000	1.0000	15.69

ROCKLAND ELECTRIC COMPANY

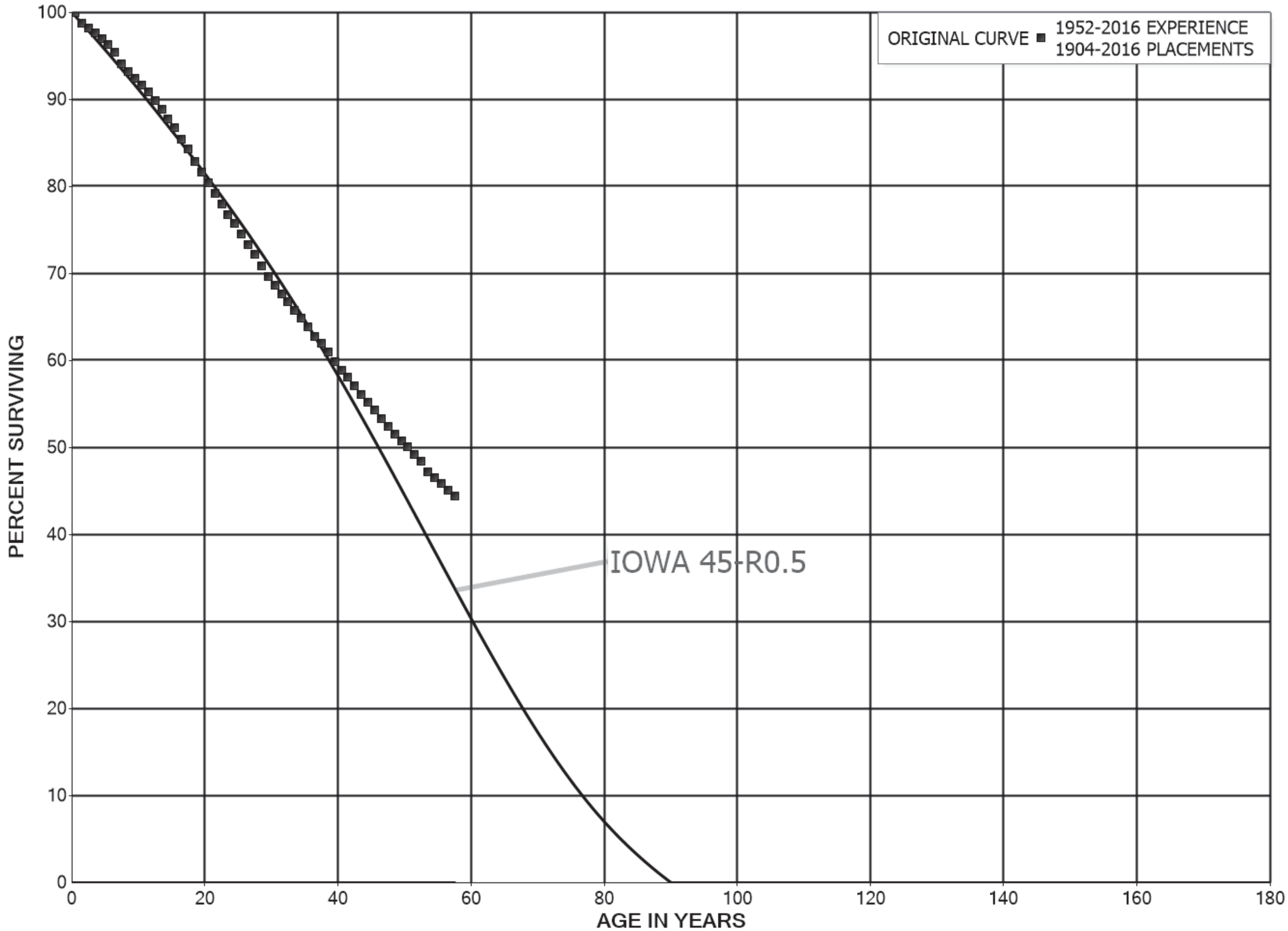
ACCOUNT 367.00 AND 367.10 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1924-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	779		0.0000	1.0000	15.69
80.5	779		0.0000	1.0000	15.69
81.5	779	1	0.0013	0.9987	15.69
82.5	778		0.0000	1.0000	15.67
83.5	778		0.0000	1.0000	15.67
84.5	778		0.0000	1.0000	15.67
85.5	778		0.0000	1.0000	15.67
86.5	778		0.0000	1.0000	15.67
87.5	778		0.0000	1.0000	15.67
88.5	778		0.0000	1.0000	15.67
89.5	778		0.0000	1.0000	15.67
90.5	778		0.0000	1.0000	15.67
91.5	778		0.0000	1.0000	15.67
92.5					15.67

ROCKLAND ELECTRIC COMPANY
ACCOUNTS 368.10, 368.20, 368.30 AND 368.40 LINE TRANSFORMERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



ROCKLAND ELECTRIC COMPANY

ACCOUNTS 368.10, 368.20, 368.30 AND 368.40 LINE TRANSFORMERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1904-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	200,143,056	174,999	0.0009	0.9991	100.00
0.5	192,105,203	2,207,817	0.0115	0.9885	99.91
1.5	184,943,806	1,165,290	0.0063	0.9937	98.76
2.5	174,376,944	1,009,549	0.0058	0.9942	98.14
3.5	164,250,814	990,732	0.0060	0.9940	97.57
4.5	159,255,203	1,066,961	0.0067	0.9933	96.99
5.5	152,377,386	1,430,816	0.0094	0.9906	96.34
6.5	145,239,943	2,097,872	0.0144	0.9856	95.43
7.5	134,605,686	1,235,273	0.0092	0.9908	94.05
8.5	122,774,116	1,036,268	0.0084	0.9916	93.19
9.5	115,295,387	972,568	0.0084	0.9916	92.40
10.5	107,549,201	880,405	0.0082	0.9918	91.62
11.5	102,279,736	1,173,419	0.0115	0.9885	90.87
12.5	97,349,867	1,112,731	0.0114	0.9886	89.83
13.5	93,617,768	1,119,976	0.0120	0.9880	88.80
14.5	88,227,178	1,071,634	0.0121	0.9879	87.74
15.5	84,798,585	1,227,980	0.0145	0.9855	86.68
16.5	80,112,865	1,098,741	0.0137	0.9863	85.42
17.5	77,139,856	1,316,091	0.0171	0.9829	84.25
18.5	73,841,907	1,066,717	0.0144	0.9856	82.81
19.5	70,901,136	1,026,164	0.0145	0.9855	81.62
20.5	68,227,223	1,057,988	0.0155	0.9845	80.43
21.5	64,981,142	1,030,912	0.0159	0.9841	79.19
22.5	61,238,072	922,858	0.0151	0.9849	77.93
23.5	58,370,188	813,494	0.0139	0.9861	76.76
24.5	55,091,309	858,327	0.0156	0.9844	75.69
25.5	51,935,937	819,595	0.0158	0.9842	74.51
26.5	48,602,812	793,429	0.0163	0.9837	73.33
27.5	45,476,354	787,704	0.0173	0.9827	72.13
28.5	42,039,795	753,020	0.0179	0.9821	70.88
29.5	38,346,152	563,464	0.0147	0.9853	69.62
30.5	35,390,995	514,582	0.0145	0.9855	68.59
31.5	32,794,733	432,272	0.0132	0.9868	67.59
32.5	30,965,997	448,465	0.0145	0.9855	66.70
33.5	29,445,666	421,332	0.0143	0.9857	65.74
34.5	28,079,221	427,921	0.0152	0.9848	64.80
35.5	26,381,135	426,256	0.0162	0.9838	63.81
36.5	24,756,429	337,254	0.0136	0.9864	62.78
37.5	23,582,304	389,616	0.0165	0.9835	61.92
38.5	22,517,629	403,632	0.0179	0.9821	60.90

ROCKLAND ELECTRIC COMPANY

ACCOUNTS 368.10, 368.20, 368.30 AND 368.40 LINE TRANSFORMERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1904-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	21,460,579	348,556	0.0162	0.9838	59.81
40.5	20,664,348	278,535	0.0135	0.9865	58.84
41.5	19,827,415	347,703	0.0175	0.9825	58.04
42.5	16,307,865	271,444	0.0166	0.9834	57.03
43.5	12,277,804	204,427	0.0167	0.9833	56.08
44.5	10,024,794	160,604	0.0160	0.9840	55.14
45.5	8,451,396	157,056	0.0186	0.9814	54.26
46.5	6,820,532	107,051	0.0157	0.9843	53.25
47.5	5,453,017	96,765	0.0177	0.9823	52.42
48.5	4,676,020	71,255	0.0152	0.9848	51.49
49.5	3,466,337	44,380	0.0128	0.9872	50.70
50.5	2,558,904	42,239	0.0165	0.9835	50.05
51.5	2,099,615	35,041	0.0167	0.9833	49.23
52.5	1,826,592	44,564	0.0244	0.9756	48.40
53.5	1,589,514	22,771	0.0143	0.9857	47.22
54.5	1,400,439	22,751	0.0162	0.9838	46.55
55.5	1,232,737	18,803	0.0153	0.9847	45.79
56.5	1,073,827	16,030	0.0149	0.9851	45.09
57.5	916,204	16,157	0.0176	0.9824	44.42
58.5	811,728	22,382	0.0276	0.9724	43.64
59.5	674,719	13,054	0.0193	0.9807	42.43
60.5	559,784	13,395	0.0239	0.9761	41.61
61.5	444,444	7,694	0.0173	0.9827	40.62
62.5	373,613	4,505	0.0121	0.9879	39.91
63.5	305,051	3,362	0.0110	0.9890	39.43
64.5	272,852	4,736	0.0174	0.9826	39.00
65.5	231,211	2,658	0.0115	0.9885	38.32
66.5	186,501	1,947	0.0104	0.9896	37.88
67.5	158,427	1,551	0.0098	0.9902	37.48
68.5	114,519	2,065	0.0180	0.9820	37.12
69.5	96,166	932	0.0097	0.9903	36.45
70.5	80,529	152	0.0019	0.9981	36.09
71.5	74,610	1,898	0.0254	0.9746	36.03
72.5	70,616	47	0.0007	0.9993	35.11
73.5	68,484	238	0.0035	0.9965	35.09
74.5	65,662	702	0.0107	0.9893	34.96
75.5	60,543	281	0.0046	0.9954	34.59
76.5	56,331	72	0.0013	0.9987	34.43
77.5	51,694	49	0.0009	0.9991	34.39
78.5	48,645	73	0.0015	0.9985	34.35

ROCKLAND ELECTRIC COMPANY

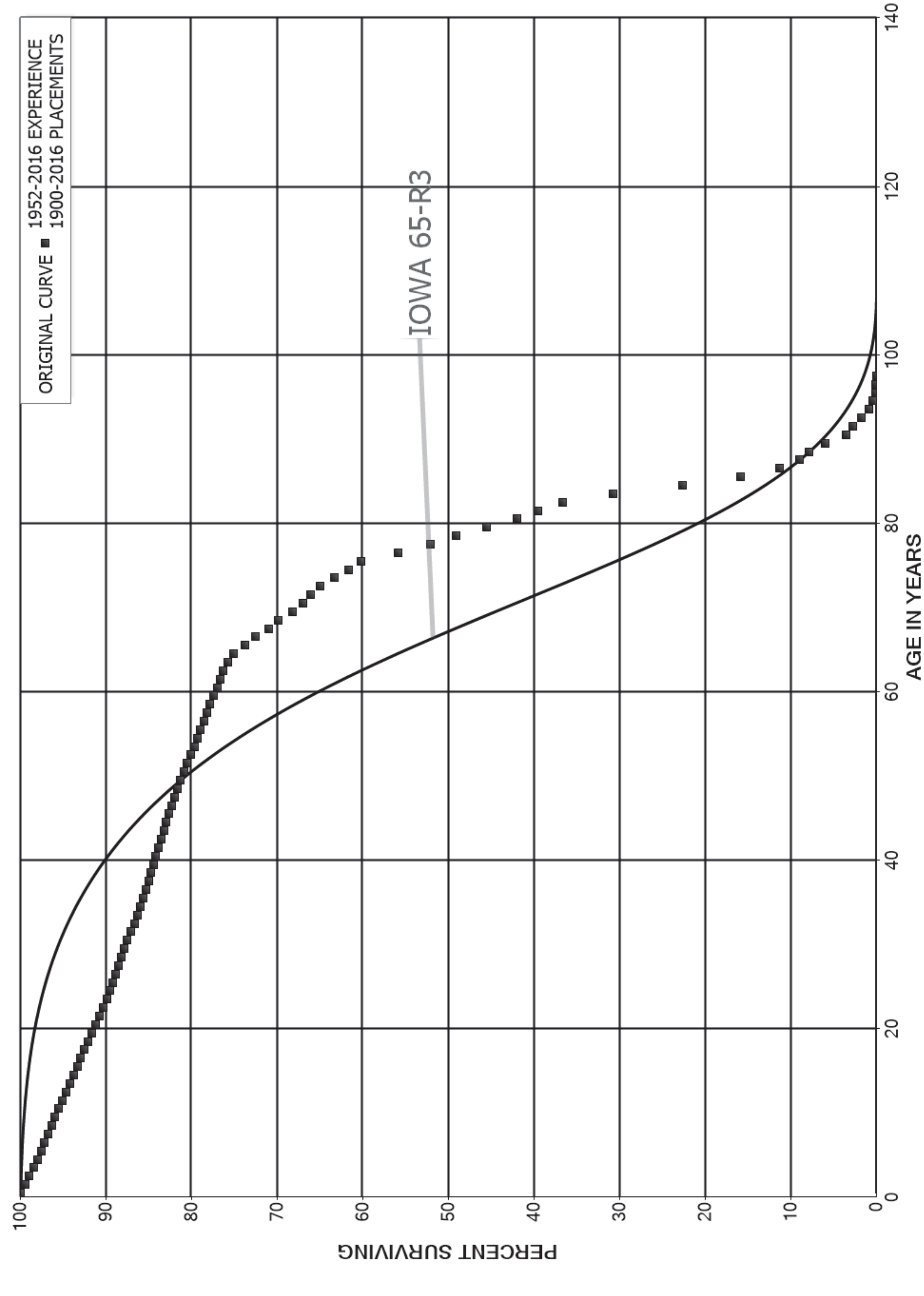
ACCOUNTS 368.10, 368.20, 368.30 AND 368.40 LINE TRANSFORMERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1904-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	43,592	245	0.0056	0.9944	34.30
80.5	38,640	179	0.0046	0.9954	34.11
81.5	37,260	328	0.0088	0.9912	33.95
82.5	36,197	155	0.0043	0.9957	33.65
83.5	35,459	38	0.0011	0.9989	33.51
84.5	35,046		0.0000	1.0000	33.47
85.5	32,704	90	0.0027	0.9973	33.47
86.5	27,869		0.0000	1.0000	33.38
87.5	24,596	98	0.0040	0.9960	33.38
88.5	21,344	1	0.0000	1.0000	33.25
89.5	18,704		0.0000	1.0000	33.25
90.5	14,372		0.0000	1.0000	33.25
91.5	10,314		0.0000	1.0000	33.25
92.5	8,706	20	0.0023	0.9977	33.25
93.5	6,917		0.0000	1.0000	33.17
94.5	5,616		0.0000	1.0000	33.17
95.5	4,641		0.0000	1.0000	33.17
96.5	3,321	74	0.0223	0.9777	33.17
97.5	3,083		0.0000	1.0000	32.43
98.5	2,260		0.0000	1.0000	32.43
99.5	1,151	2	0.0017	0.9983	32.43
100.5	812		0.0000	1.0000	32.37
101.5	569		0.0000	1.0000	32.37
102.5	569	268	0.4709	0.5291	32.37
103.5	90	50	0.5534	0.4466	17.13
104.5	40		0.0000	1.0000	7.65
105.5	40		0.0000	1.0000	7.65
106.5	40	40	1.0000		7.65
107.5					

ROCKLAND ELECTRIC COMPANY
ACCOUNT 369.10 SERVICES - OVERHEAD
ORIGINAL AND SMOOTH SURVIVOR CURVES



ROCKLAND ELECTRIC COMPANY

ACCOUNT 369.10 SERVICES - OVERHEAD

ORIGINAL LIFE TABLE

PLACEMENT BAND 1900-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	24,496,223	14,530	0.0006	0.9994	100.00
0.5	24,007,964	137,928	0.0057	0.9943	99.94
1.5	23,422,037	108,004	0.0046	0.9954	99.37
2.5	22,985,361	107,349	0.0047	0.9953	98.91
3.5	22,466,345	101,051	0.0045	0.9955	98.45
4.5	22,045,189	100,128	0.0045	0.9955	98.00
5.5	21,653,965	94,620	0.0044	0.9956	97.56
6.5	21,213,272	85,377	0.0040	0.9960	97.13
7.5	20,807,397	90,439	0.0043	0.9957	96.74
8.5	20,348,381	86,948	0.0043	0.9957	96.32
9.5	19,901,954	89,043	0.0045	0.9955	95.91
10.5	19,555,498	89,164	0.0046	0.9954	95.48
11.5	19,180,701	85,441	0.0045	0.9955	95.04
12.5	18,842,959	79,998	0.0042	0.9958	94.62
13.5	18,525,740	88,831	0.0048	0.9952	94.22
14.5	18,207,944	85,270	0.0047	0.9953	93.77
15.5	17,917,133	77,394	0.0043	0.9957	93.33
16.5	17,663,290	88,136	0.0050	0.9950	92.93
17.5	17,410,566	79,064	0.0045	0.9955	92.46
18.5	17,126,531	87,042	0.0051	0.9949	92.04
19.5	16,798,783	75,551	0.0045	0.9955	91.57
20.5	16,493,934	85,544	0.0052	0.9948	91.16
21.5	16,143,760	70,466	0.0044	0.9956	90.69
22.5	15,744,509	71,881	0.0046	0.9954	90.29
23.5	15,352,408	59,049	0.0038	0.9962	89.88
24.5	14,938,547	59,646	0.0040	0.9960	89.54
25.5	14,255,017	55,307	0.0039	0.9961	89.18
26.5	13,342,481	52,226	0.0039	0.9961	88.83
27.5	12,336,785	46,764	0.0038	0.9962	88.48
28.5	11,530,957	44,793	0.0039	0.9961	88.15
29.5	10,583,175	40,702	0.0038	0.9962	87.81
30.5	9,875,175	45,823	0.0046	0.9954	87.47
31.5	9,263,116	45,241	0.0049	0.9951	87.06
32.5	8,743,243	34,271	0.0039	0.9961	86.64
33.5	8,313,377	32,931	0.0040	0.9960	86.30
34.5	7,925,457	30,616	0.0039	0.9961	85.96
35.5	7,577,236	29,294	0.0039	0.9961	85.62
36.5	7,177,326	25,495	0.0036	0.9964	85.29
37.5	6,818,422	22,584	0.0033	0.9967	84.99
38.5	6,497,749	22,796	0.0035	0.9965	84.71

ROCKLAND ELECTRIC COMPANY

ACCOUNT 369.10 SERVICES - OVERHEAD

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	6,158,897	21,117	0.0034	0.9966	84.41
40.5	5,823,407	20,888	0.0036	0.9964	84.12
41.5	5,445,500	19,313	0.0035	0.9965	83.82
42.5	5,023,914	18,866	0.0038	0.9962	83.52
43.5	4,503,264	15,041	0.0033	0.9967	83.21
44.5	4,078,269	15,137	0.0037	0.9963	82.93
45.5	3,739,352	15,090	0.0040	0.9960	82.62
46.5	3,361,601	13,620	0.0041	0.9959	82.29
47.5	3,079,560	12,100	0.0039	0.9961	81.96
48.5	2,799,345	11,566	0.0041	0.9959	81.64
49.5	2,553,215	12,831	0.0050	0.9950	81.30
50.5	2,287,290	10,297	0.0045	0.9955	80.89
51.5	2,030,940	10,276	0.0051	0.9949	80.53
52.5	1,811,110	10,633	0.0059	0.9941	80.12
53.5	1,608,963	7,215	0.0045	0.9955	79.65
54.5	1,382,379	6,531	0.0047	0.9953	79.29
55.5	1,166,436	5,981	0.0051	0.9949	78.92
56.5	956,016	4,273	0.0045	0.9955	78.51
57.5	762,846	3,660	0.0048	0.9952	78.16
58.5	605,645	2,721	0.0045	0.9955	77.78
59.5	449,068	2,681	0.0060	0.9940	77.44
60.5	338,242	1,489	0.0044	0.9956	76.97
61.5	276,117	1,449	0.0052	0.9948	76.63
62.5	227,761	1,366	0.0060	0.9940	76.23
63.5	167,741	1,644	0.0098	0.9902	75.78
64.5	145,837	2,510	0.0172	0.9828	75.03
65.5	121,364	2,025	0.0167	0.9833	73.74
66.5	99,801	2,178	0.0218	0.9782	72.51
67.5	82,632	1,210	0.0146	0.9854	70.93
68.5	69,469	1,653	0.0238	0.9762	69.89
69.5	57,795	1,097	0.0190	0.9810	68.23
70.5	50,659	696	0.0137	0.9863	66.93
71.5	47,943	801	0.0167	0.9833	66.01
72.5	46,258	1,131	0.0244	0.9756	64.91
73.5	44,655	1,181	0.0265	0.9735	63.32
74.5	41,692	992	0.0238	0.9762	61.65
75.5	37,508	2,677	0.0714	0.9286	60.18
76.5	32,314	2,184	0.0676	0.9324	55.88
77.5	28,214	1,673	0.0593	0.9407	52.11
78.5	24,163	1,727	0.0715	0.9285	49.02

ROCKLAND ELECTRIC COMPANY

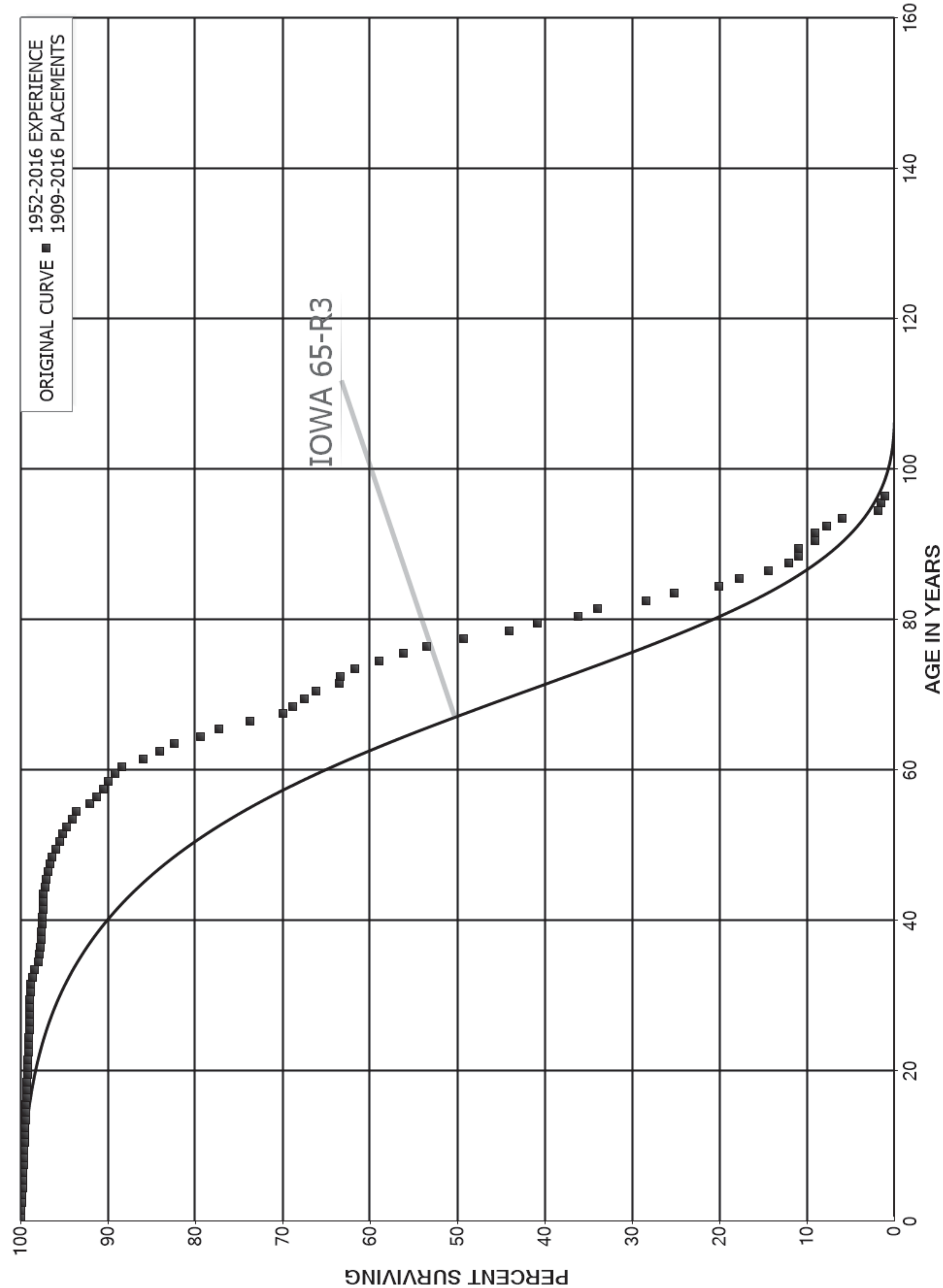
ACCOUNT 369.10 SERVICES - OVERHEAD

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	20,250	1,576	0.0778	0.9222	45.51
80.5	16,937	1,003	0.0592	0.9408	41.97
81.5	14,305	1,022	0.0715	0.9285	39.48
82.5	12,005	1,936	0.1613	0.8387	36.66
83.5	9,718	2,570	0.2644	0.7356	30.75
84.5	6,929	2,070	0.2988	0.7012	22.62
85.5	4,851	1,390	0.2866	0.7134	15.86
86.5	3,236	675	0.2085	0.7915	11.31
87.5	2,347	307	0.1310	0.8690	8.95
88.5	1,930	466	0.2414	0.7586	7.78
89.5	1,349	545	0.4041	0.5959	5.90
90.5	734	161	0.2195	0.7805	3.52
91.5	573	207	0.3616	0.6384	2.75
92.5	366	189	0.5171	0.4829	1.75
93.5	177	89	0.5067	0.4933	0.85
94.5	28	20	0.7138	0.2862	0.42
95.5	8	5	0.6234	0.3766	0.12
96.5	3	3	1.0000		0.04
97.5					

ROCKLAND ELECTRIC COMPANY
ACCOUNT 369.20 SERVICES - UNDERGROUND
ORIGINAL AND SMOOTH SURVIVOR CURVES



ROCKLAND ELECTRIC COMPANY

ACCOUNT 369.20 SERVICES - UNDERGROUND

ORIGINAL LIFE TABLE

PLACEMENT BAND 1909-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	37,757,976	4,060	0.0001	0.9999	100.00
0.5	36,112,978	25,400	0.0007	0.9993	99.99
1.5	34,633,235	11,464	0.0003	0.9997	99.92
2.5	32,956,100	21,362	0.0006	0.9994	99.89
3.5	31,629,810	13,639	0.0004	0.9996	99.82
4.5	30,511,247	17,188	0.0006	0.9994	99.78
5.5	29,388,862	9,260	0.0003	0.9997	99.72
6.5	28,395,415	12,356	0.0004	0.9996	99.69
7.5	27,437,345	9,134	0.0003	0.9997	99.65
8.5	26,271,073	9,962	0.0004	0.9996	99.61
9.5	25,042,462	10,417	0.0004	0.9996	99.58
10.5	23,685,154	8,651	0.0004	0.9996	99.53
11.5	22,517,009	8,393	0.0004	0.9996	99.50
12.5	21,318,227	7,572	0.0004	0.9996	99.46
13.5	20,315,718	7,741	0.0004	0.9996	99.43
14.5	19,289,135	7,585	0.0004	0.9996	99.39
15.5	18,242,648	6,015	0.0003	0.9997	99.35
16.5	17,211,755	7,436	0.0004	0.9996	99.32
17.5	16,189,253	3,905	0.0002	0.9998	99.27
18.5	15,436,324	6,206	0.0004	0.9996	99.25
19.5	14,614,707	6,846	0.0005	0.9995	99.21
20.5	13,718,482	4,937	0.0004	0.9996	99.16
21.5	12,863,044	5,242	0.0004	0.9996	99.13
22.5	11,956,750	4,742	0.0004	0.9996	99.09
23.5	11,184,393	3,157	0.0003	0.9997	99.05
24.5	10,429,555	2,173	0.0002	0.9998	99.02
25.5	9,829,054	1,261	0.0001	0.9999	99.00
26.5	9,178,313	3,567	0.0004	0.9996	98.99
27.5	8,618,218	2,479	0.0003	0.9997	98.95
28.5	8,062,106	1,154	0.0001	0.9999	98.92
29.5	7,374,252	3,050	0.0004	0.9996	98.91
30.5	6,651,479	5,098	0.0008	0.9992	98.86
31.5	5,743,199	10,045	0.0017	0.9983	98.79
32.5	4,913,966	13,266	0.0027	0.9973	98.62
33.5	4,328,032	19,483	0.0045	0.9955	98.35
34.5	3,912,509	3,386	0.0009	0.9991	97.91
35.5	3,549,406	3,125	0.0009	0.9991	97.82
36.5	3,219,862	2,954	0.0009	0.9991	97.74
37.5	2,846,444	1,652	0.0006	0.9994	97.65
38.5	2,475,699	1,476	0.0006	0.9994	97.59

ROCKLAND ELECTRIC COMPANY

ACCOUNT 369.20 SERVICES - UNDERGROUND

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1909-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	2,153,757	1,690	0.0008	0.9992	97.53
40.5	1,863,478	851	0.0005	0.9995	97.45
41.5	1,685,479	353	0.0002	0.9998	97.41
42.5	1,376,476	603	0.0004	0.9996	97.39
43.5	1,101,496	1,412	0.0013	0.9987	97.35
44.5	705,323	1,374	0.0019	0.9981	97.22
45.5	565,248	1,234	0.0022	0.9978	97.03
46.5	351,216	846	0.0024	0.9976	96.82
47.5	278,608	546	0.0020	0.9980	96.59
48.5	193,528	935	0.0048	0.9952	96.40
49.5	155,604	698	0.0045	0.9955	95.93
50.5	127,580	510	0.0040	0.9960	95.50
51.5	107,198	477	0.0044	0.9956	95.12
52.5	80,618	554	0.0069	0.9931	94.70
53.5	66,852	271	0.0041	0.9959	94.05
54.5	56,444	981	0.0174	0.9826	93.67
55.5	46,040	371	0.0081	0.9919	92.04
56.5	37,115	320	0.0086	0.9914	91.30
57.5	30,422	182	0.0060	0.9940	90.51
58.5	24,359	216	0.0089	0.9911	89.97
59.5	18,380	159	0.0086	0.9914	89.17
60.5	15,162	423	0.0279	0.9721	88.40
61.5	11,562	256	0.0222	0.9778	85.94
62.5	9,806	186	0.0190	0.9810	84.03
63.5	7,902	290	0.0367	0.9633	82.43
64.5	6,910	182	0.0264	0.9736	79.41
65.5	5,893	272	0.0461	0.9539	77.31
66.5	4,860	249	0.0512	0.9488	73.75
67.5	4,374	71	0.0163	0.9837	69.97
68.5	4,042	81	0.0200	0.9800	68.83
69.5	3,821	70	0.0183	0.9817	67.46
70.5	3,628	147	0.0404	0.9596	66.22
71.5	3,425	11	0.0031	0.9969	63.54
72.5	3,394	87	0.0256	0.9744	63.35
73.5	3,300	151	0.0457	0.9543	61.72
74.5	3,095	144	0.0465	0.9535	58.90
75.5	2,841	132	0.0465	0.9535	56.16
76.5	2,516	198	0.0787	0.9213	53.55
77.5	2,217	235	0.1059	0.8941	49.34
78.5	1,906	143	0.0751	0.9249	44.11

ROCKLAND ELECTRIC COMPANY

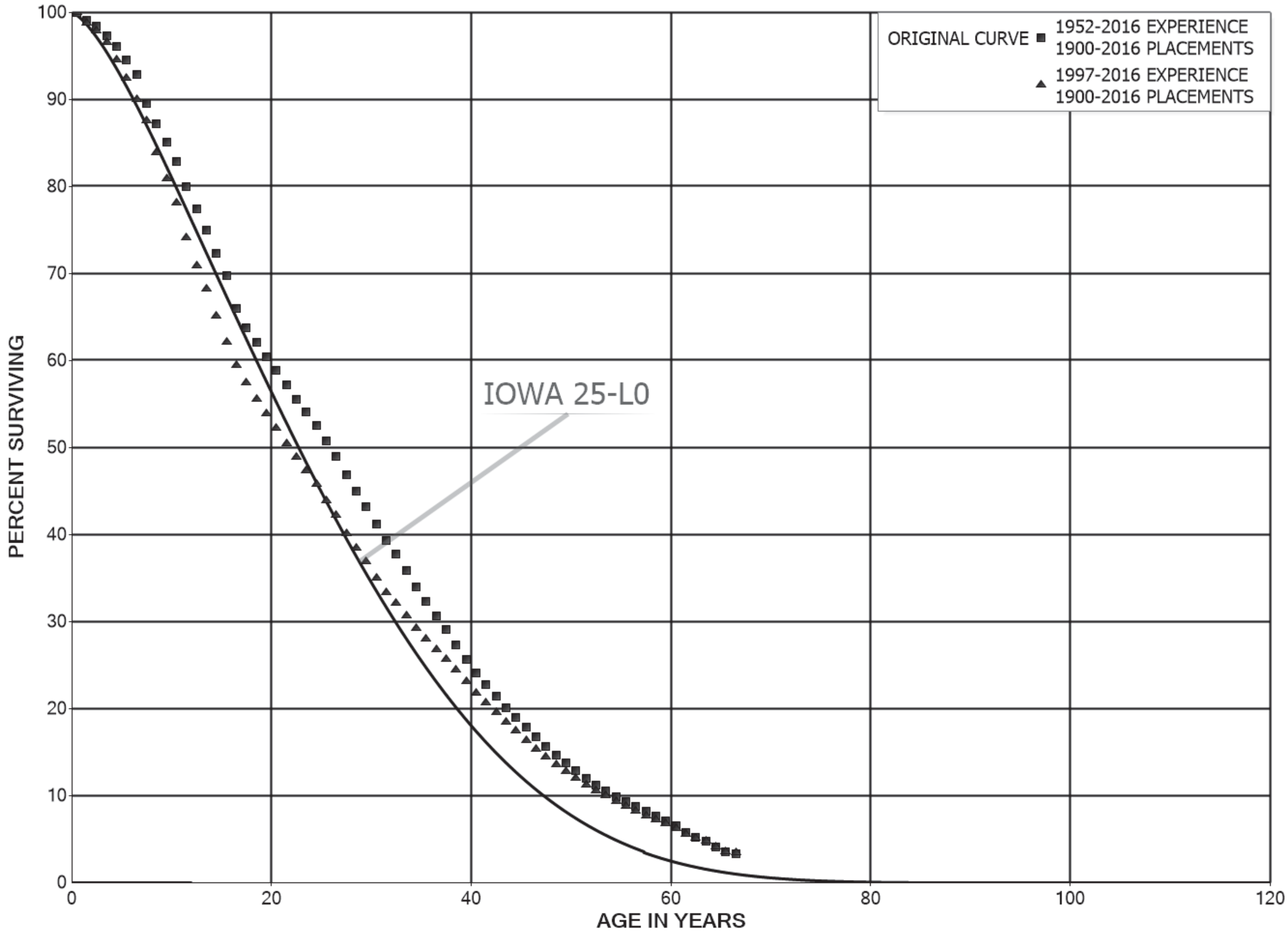
ACCOUNT 369.20 SERVICES - UNDERGROUND

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1909-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	1,542	177	0.1146	0.8854	40.80
80.5	1,286	76	0.0593	0.9407	36.12
81.5	1,101	180	0.1633	0.8367	33.98
82.5	903	103	0.1138	0.8862	28.43
83.5	665	136	0.2044	0.7956	25.19
84.5	451	53	0.1166	0.8834	20.05
85.5	287	53	0.1853	0.8147	17.71
86.5	197	32	0.1621	0.8379	14.43
87.5	130	12	0.0923	0.9077	12.09
88.5	110		0.0000	1.0000	10.97
89.5	101	18	0.1786	0.8214	10.97
90.5	83		0.0000	1.0000	9.01
91.5	83	12	0.1449	0.8551	9.01
92.5	71	16	0.2207	0.7793	7.71
93.5	55	38	0.6887	0.3113	6.01
94.5	17	3	0.1746	0.8254	1.87
95.5	14	5	0.3216	0.6784	1.54
96.5	10		0.0000	1.0000	1.05
97.5	10	5	0.4886	0.5114	1.05
98.5	5		0.0000	1.0000	0.54
99.5	5		0.0000	1.0000	0.54
100.5	5	5	1.0000		0.54
101.5					

ROCKLAND ELECTRIC COMPANY
ACCOUNTS 370.10 AND 370.20 METERS AND INSTALLATIONS - ELECTROMECHANICAL
ORIGINAL AND SMOOTH SURVIVOR CURVES



ROCKLAND ELECTRIC COMPANY

ACCOUNTS 370.10 AND 370.20 METERS AND INSTALLATIONS - ELECTROMECHANICAL

ORIGINAL LIFE TABLE

PLACEMENT BAND 1900-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	31,408,204	2,986	0.0001	0.9999	100.00
0.5	31,555,761	300,622	0.0095	0.9905	99.99
1.5	31,389,308	201,374	0.0064	0.9936	99.04
2.5	31,347,013	350,648	0.0112	0.9888	98.40
3.5	31,110,160	406,501	0.0131	0.9869	97.30
4.5	30,711,863	493,060	0.0161	0.9839	96.03
5.5	30,146,064	513,958	0.0170	0.9830	94.49
6.5	29,511,730	1,089,031	0.0369	0.9631	92.88
7.5	28,423,511	717,444	0.0252	0.9748	89.45
8.5	27,707,305	689,783	0.0249	0.9751	87.19
9.5	27,030,348	680,797	0.0252	0.9748	85.02
10.5	26,409,600	947,449	0.0359	0.9641	82.88
11.5	25,517,100	798,768	0.0313	0.9687	79.91
12.5	24,742,857	786,084	0.0318	0.9682	77.41
13.5	22,744,275	793,501	0.0349	0.9651	74.95
14.5	21,129,368	758,466	0.0359	0.9641	72.33
15.5	19,481,620	1,053,053	0.0541	0.9459	69.74
16.5	18,047,916	608,319	0.0337	0.9663	65.97
17.5	16,805,025	454,691	0.0271	0.9729	63.74
18.5	15,603,033	407,015	0.0261	0.9739	62.02
19.5	14,774,716	388,137	0.0263	0.9737	60.40
20.5	13,899,577	394,108	0.0284	0.9716	58.81
21.5	12,923,535	359,463	0.0278	0.9722	57.15
22.5	12,256,475	323,976	0.0264	0.9736	55.56
23.5	11,449,440	327,072	0.0286	0.9714	54.09
24.5	10,634,591	377,875	0.0355	0.9645	52.54
25.5	9,917,007	348,280	0.0351	0.9649	50.68
26.5	9,120,313	391,131	0.0429	0.9571	48.90
27.5	8,623,688	330,172	0.0383	0.9617	46.80
28.5	6,973,333	281,195	0.0403	0.9597	45.01
29.5	6,305,178	302,143	0.0479	0.9521	43.19
30.5	5,720,938	249,733	0.0437	0.9563	41.12
31.5	5,255,873	219,143	0.0417	0.9583	39.33
32.5	4,168,540	204,126	0.0490	0.9510	37.69
33.5	3,802,064	199,597	0.0525	0.9475	35.84
34.5	3,491,313	177,330	0.0508	0.9492	33.96
35.5	3,178,257	157,535	0.0496	0.9504	32.24
36.5	2,926,559	150,915	0.0516	0.9484	30.64
37.5	2,631,619	162,477	0.0617	0.9383	29.06
38.5	2,396,257	143,834	0.0600	0.9400	27.26

ROCKLAND ELECTRIC COMPANY

ACCOUNTS 370.10 AND 370.20 METERS AND INSTALLATIONS - ELECTROMECHANICAL

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	2,190,110	135,177	0.0617	0.9383	25.63
40.5	1,998,750	111,751	0.0559	0.9441	24.05
41.5	1,832,193	104,462	0.0570	0.9430	22.70
42.5	1,682,439	101,957	0.0606	0.9394	21.41
43.5	1,490,984	84,972	0.0570	0.9430	20.11
44.5	1,328,733	81,986	0.0617	0.9383	18.96
45.5	1,191,676	73,143	0.0614	0.9386	17.79
46.5	1,055,681	65,679	0.0622	0.9378	16.70
47.5	947,185	60,327	0.0637	0.9363	15.66
48.5	826,127	55,812	0.0676	0.9324	14.66
49.5	716,446	45,869	0.0640	0.9360	13.67
50.5	615,853	43,192	0.0701	0.9299	12.80
51.5	535,124	34,822	0.0651	0.9349	11.90
52.5	444,773	25,609	0.0576	0.9424	11.13
53.5	362,644	22,160	0.0611	0.9389	10.49
54.5	288,473	16,888	0.0585	0.9415	9.85
55.5	229,120	13,925	0.0608	0.9392	9.27
56.5	188,726	12,093	0.0641	0.9359	8.71
57.5	144,508	10,395	0.0719	0.9281	8.15
58.5	108,958	7,406	0.0680	0.9320	7.56
59.5	84,133	5,919	0.0704	0.9296	7.05
60.5	65,118	7,864	0.1208	0.8792	6.55
61.5	49,739	5,395	0.1085	0.8915	5.76
62.5	39,414	2,742	0.0696	0.9304	5.14
63.5	31,329	4,775	0.1524	0.8476	4.78
64.5	23,901	3,027	0.1266	0.8734	4.05
65.5	15,019	1,225	0.0816	0.9184	3.54
66.5	9,153	938	0.1024	0.8976	3.25
67.5	6,642	993	0.1496	0.8504	2.92
68.5	5,383	605	0.1123	0.8877	2.48
69.5	4,619	575	0.1244	0.8756	2.20
70.5	4,003	109	0.0273	0.9727	1.93
71.5	3,893	191	0.0490	0.9510	1.87
72.5	3,703	233	0.0628	0.9372	1.78
73.5	3,470	141	0.0406	0.9594	1.67
74.5	3,298	61	0.0185	0.9815	1.60
75.5	3,153	67	0.0211	0.9789	1.57
76.5	3,030	21	0.0070	0.9930	1.54
77.5	2,973	83	0.0279	0.9721	1.53
78.5	2,870	113	0.0394	0.9606	1.49

ROCKLAND ELECTRIC COMPANY

ACCOUNTS 370.10 AND 370.20 METERS AND INSTALLATIONS - ELECTROMECHANICAL

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	2,757	122	0.0443	0.9557	1.43
80.5	2,635	66	0.0250	0.9750	1.36
81.5	2,569	52	0.0202	0.9798	1.33
82.5	2,517	162	0.0644	0.9356	1.30
83.5	2,355	53	0.0225	0.9775	1.22
84.5	2,302	45	0.0195	0.9805	1.19
85.5	2,257		0.0000	1.0000	1.17
86.5	2,257		0.0000	1.0000	1.17
87.5	2,257	23	0.0102	0.9898	1.17
88.5	2,234		0.0000	1.0000	1.16
89.5	2,223		0.0000	1.0000	1.16
90.5	2,223		0.0000	1.0000	1.16
91.5	2,223		0.0000	1.0000	1.16
92.5	2,223		0.0000	1.0000	1.16
93.5	2,223		0.0000	1.0000	1.16
94.5	2,210		0.0000	1.0000	1.16
95.5	2,210		0.0000	1.0000	1.16
96.5	2,210		0.0000	1.0000	1.16
97.5	2,210	23	0.0104	0.9896	1.16
98.5	2,187		0.0000	1.0000	1.15
99.5	2,187	39	0.0178	0.9822	1.15
100.5	2,148	23	0.0107	0.9893	1.12
101.5	2,125	23	0.0108	0.9892	1.11
102.5	2,102	48	0.0228	0.9772	1.10
103.5	2,054	47	0.0229	0.9771	1.08
104.5	2,007	47	0.0234	0.9766	1.05
105.5	1,960		0.0000	1.0000	1.03
106.5	1,960		0.0000	1.0000	1.03
107.5	1,960	48	0.0244	0.9756	1.03
108.5	1,912		0.0000	1.0000	1.00
109.5	1,912	120	0.0625	0.9375	1.00
110.5	1,793	24	0.0133	0.9867	0.94
111.5	1,769	72	0.0405	0.9595	0.93
112.5	1,697	24	0.0141	0.9859	0.89
113.5	1,673	48	0.0286	0.9714	0.88
114.5	1,625		0.0000	1.0000	0.85
115.5					0.85

ROCKLAND ELECTRIC COMPANY

ACCOUNTS 370.10 AND 370.20 METERS AND INSTALLATIONS - ELECTROMECHANICAL

ORIGINAL LIFE TABLE

PLACEMENT BAND 1900-2016 EXPERIENCE BAND 1997-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	9,120,142		0.0000	1.0000	100.00
0.5	10,150,355	131,331	0.0129	0.9871	100.00
1.5	11,435,816	100,634	0.0088	0.9912	98.71
2.5	12,143,903	168,285	0.0139	0.9861	97.84
3.5	13,164,208	269,207	0.0204	0.9796	96.48
4.5	14,131,071	320,456	0.0227	0.9773	94.51
5.5	14,597,987	388,571	0.0266	0.9734	92.37
6.5	15,055,763	397,385	0.0264	0.9736	89.91
7.5	14,952,220	622,791	0.0417	0.9583	87.53
8.5	16,504,808	599,924	0.0363	0.9637	83.89
9.5	17,114,666	595,693	0.0348	0.9652	80.84
10.5	17,317,847	879,375	0.0508	0.9492	78.03
11.5	17,073,712	734,844	0.0430	0.9570	74.06
12.5	17,911,066	694,847	0.0388	0.9612	70.88
13.5	16,371,217	736,774	0.0450	0.9550	68.13
14.5	15,051,190	686,834	0.0456	0.9544	65.06
15.5	13,787,374	607,290	0.0440	0.9560	62.09
16.5	13,001,252	440,049	0.0338	0.9662	59.36
17.5	12,238,330	394,719	0.0323	0.9677	57.35
18.5	11,243,403	338,426	0.0301	0.9699	55.50
19.5	10,603,892	330,426	0.0312	0.9688	53.83
20.5	9,895,280	334,552	0.0338	0.9662	52.15
21.5	9,083,375	289,560	0.0319	0.9681	50.39
22.5	8,572,587	257,269	0.0300	0.9700	48.78
23.5	8,040,525	265,822	0.0331	0.9669	47.32
24.5	7,441,670	305,784	0.0411	0.9589	45.75
25.5	6,898,075	265,083	0.0384	0.9616	43.87
26.5	6,318,838	314,044	0.0497	0.9503	42.19
27.5	5,990,974	248,030	0.0414	0.9586	40.09
28.5	4,529,861	190,707	0.0421	0.9579	38.43
29.5	4,055,285	211,370	0.0521	0.9479	36.81
30.5	3,697,884	165,867	0.0449	0.9551	34.89
31.5	3,414,141	129,978	0.0381	0.9619	33.33
32.5	2,555,875	113,471	0.0444	0.9556	32.06
33.5	2,409,639	113,304	0.0470	0.9530	30.64
34.5	2,300,098	100,680	0.0438	0.9562	29.20
35.5	2,167,965	90,833	0.0419	0.9581	27.92
36.5	2,052,186	90,553	0.0441	0.9559	26.75
37.5	1,900,434	89,419	0.0471	0.9529	25.57
38.5	1,808,630	93,382	0.0516	0.9484	24.36

ROCKLAND ELECTRIC COMPANY

ACCOUNTS 370.10 AND 370.20 METERS AND INSTALLATIONS - ELECTROMECHANICAL

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2016 EXPERIENCE BAND 1997-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	1,714,245	101,044	0.0589	0.9411	23.11
40.5	1,617,930	80,110	0.0495	0.9505	21.74
41.5	1,528,237	82,745	0.0541	0.9459	20.67
42.5	1,431,775	83,255	0.0581	0.9419	19.55
43.5	1,294,366	73,942	0.0571	0.9429	18.41
44.5	1,162,366	71,603	0.0616	0.9384	17.36
45.5	1,069,708	65,778	0.0615	0.9385	16.29
46.5	966,949	58,469	0.0605	0.9395	15.29
47.5	877,174	49,709	0.0567	0.9433	14.36
48.5	769,380	47,425	0.0616	0.9384	13.55
49.5	670,278	40,793	0.0609	0.9391	12.72
50.5	573,342	38,387	0.0670	0.9330	11.94
51.5	497,521	29,736	0.0598	0.9402	11.14
52.5	412,256	22,744	0.0552	0.9448	10.48
53.5	333,001	19,367	0.0582	0.9418	9.90
54.5	261,927	16,003	0.0611	0.9389	9.32
55.5	204,460	12,943	0.0633	0.9367	8.75
56.5	166,136	10,884	0.0655	0.9345	8.20
57.5	123,755	7,400	0.0598	0.9402	7.66
58.5	91,549	6,016	0.0657	0.9343	7.20
59.5	68,156	5,249	0.0770	0.9230	6.73
60.5	49,810	5,361	0.1076	0.8924	6.21
61.5	36,954	3,376	0.0913	0.9087	5.54
62.5	28,649	1,696	0.0592	0.9408	5.04
63.5	21,609	2,921	0.1352	0.8648	4.74
64.5	16,042	2,146	0.1338	0.8662	4.10
65.5	8,041	326	0.0406	0.9594	3.55
66.5	3,074	349	0.1134	0.8866	3.41
67.5	1,190	89	0.0752	0.9248	3.02
68.5	835	132	0.1577	0.8423	2.79
69.5	555	61	0.1092	0.8908	2.35
70.5	453	8	0.0184	0.9816	2.10
71.5	444	16	0.0355	0.9645	2.06
72.5	429	65	0.1508	0.8492	1.98
73.5	364	28	0.0768	0.9232	1.68
74.5	318	51	0.1605	0.8395	1.56
75.5	183	26	0.1397	0.8603	1.31
76.5	101	21	0.2096	0.7904	1.12
77.5	44		0.0000	1.0000	0.89
78.5	24		0.0000	1.0000	0.89

ROCKLAND ELECTRIC COMPANY

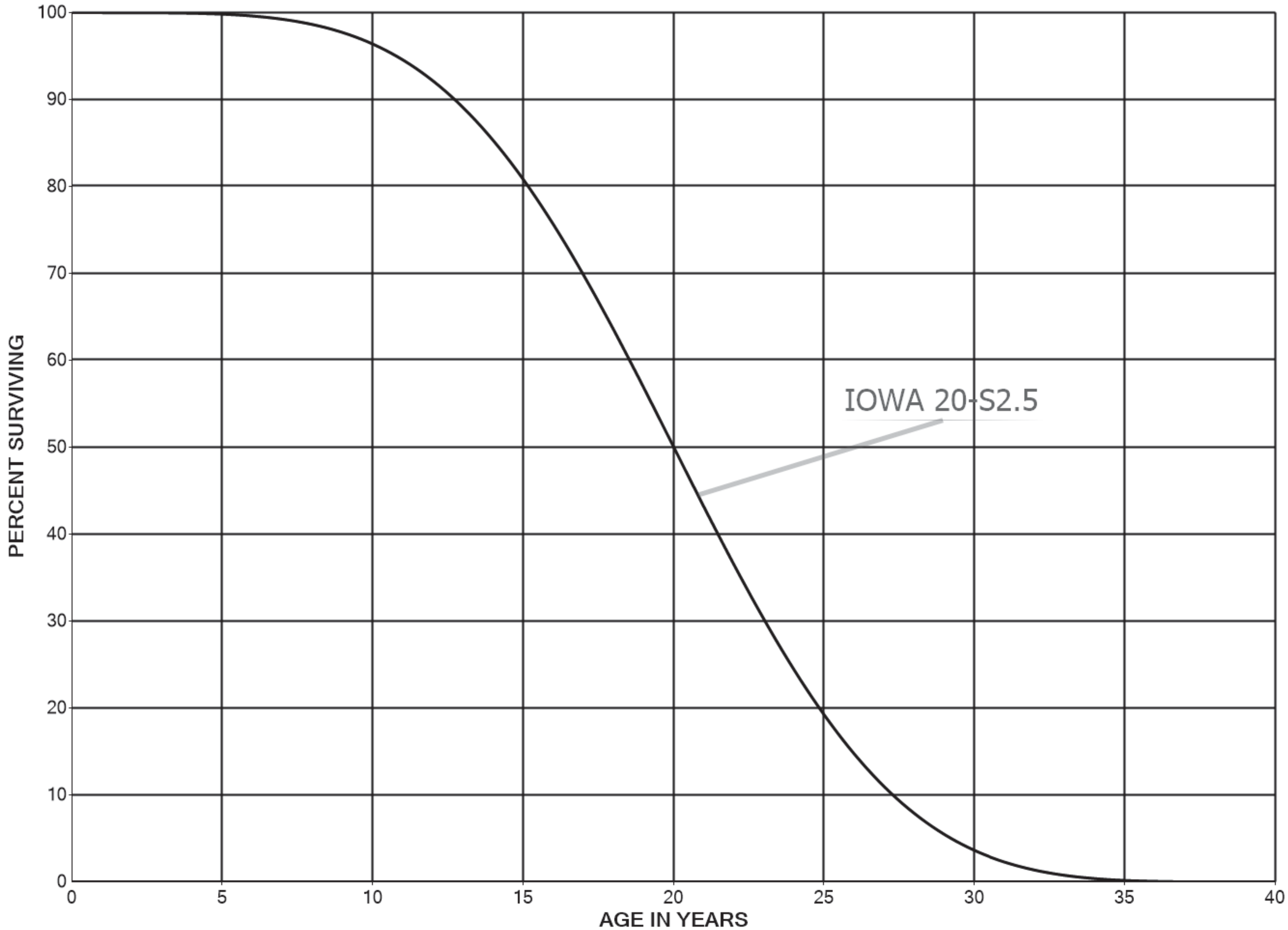
ACCOUNTS 370.10 AND 370.20 METERS AND INSTALLATIONS - ELECTROMECHANICAL

ORIGINAL LIFE TABLE, CONT.

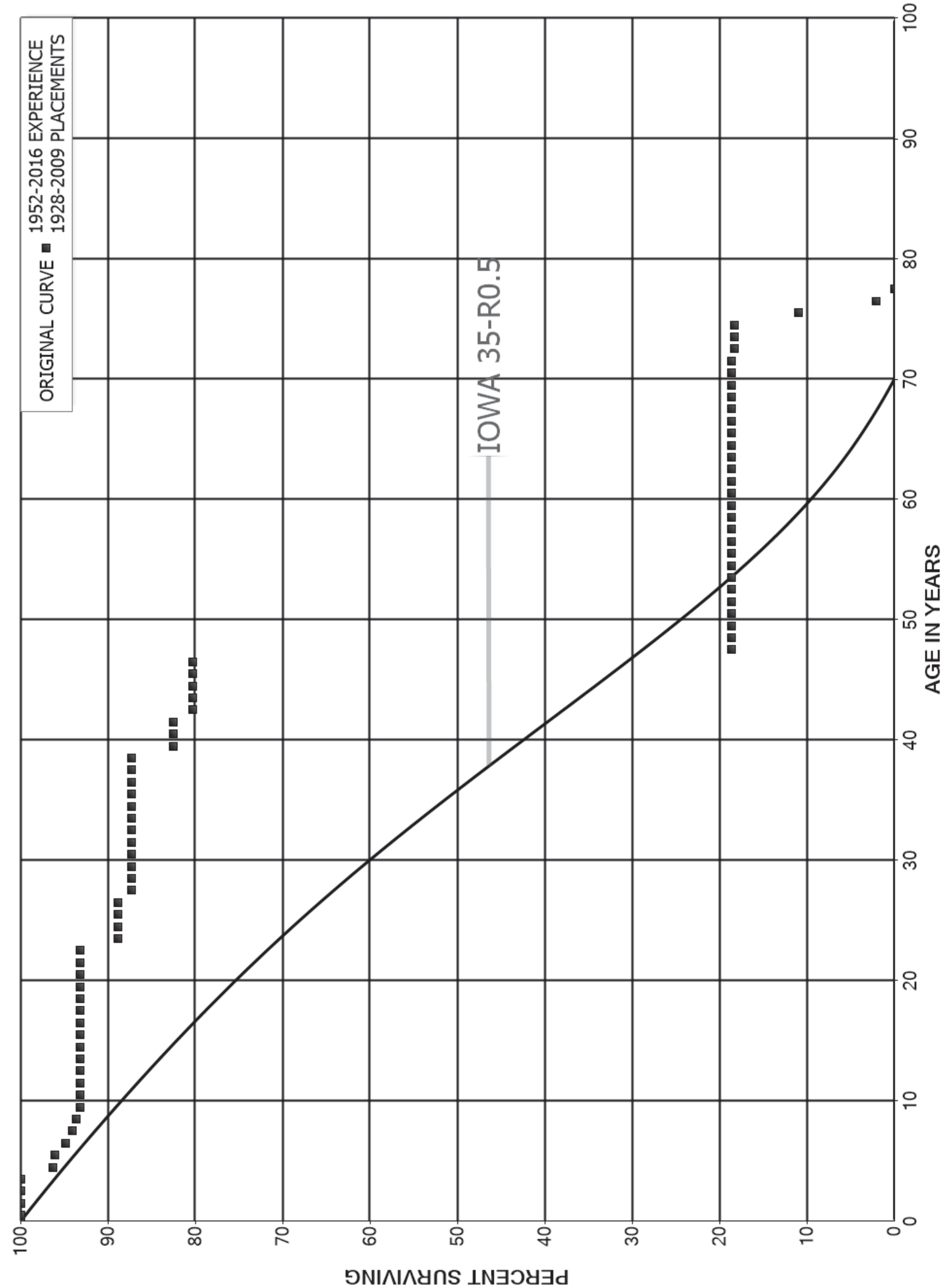
PLACEMENT BAND 1900-2016 EXPERIENCE BAND 1997-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	24		0.0000	1.0000	0.89
80.5	24		0.0000	1.0000	0.89
81.5	24		0.0000	1.0000	0.89
82.5	24		0.0000	1.0000	0.89
83.5	24		0.0000	1.0000	0.89
84.5	24		0.0000	1.0000	0.89
85.5	24		0.0000	1.0000	0.89
86.5	24		0.0000	1.0000	0.89
87.5	24		0.0000	1.0000	0.89
88.5	24		0.0000	1.0000	0.89
89.5	13		0.0000	1.0000	0.89
90.5	13		0.0000	1.0000	0.89
91.5	13		0.0000	1.0000	0.89
92.5	13		0.0000	1.0000	0.89
93.5	13		0.0000	1.0000	0.89
94.5					0.89
95.5	2,194		0.0000		
96.5	2,210		0.0000		
97.5	2,210	23	0.0104		
98.5	2,187		0.0000		
99.5	2,187	39	0.0178		
100.5	2,148	23	0.0107		
101.5	2,125	23	0.0108		
102.5	2,102	48	0.0228		
103.5	2,054	47	0.0229		
104.5	2,007	47	0.0234		
105.5	1,960		0.0000		
106.5	1,960		0.0000		
107.5	1,960	48	0.0244		
108.5	1,912		0.0000		
109.5	1,912	120	0.0625		
110.5	1,793	24	0.0133		
111.5	1,769	72	0.0405		
112.5	1,697	24	0.0141		
113.5	1,673	48	0.0286		
114.5	1,625		0.0000		
115.5					

ROCKLAND ELECTRIC COMPANY
ACCOUNTS 370.11 AND 370.21 METERS AND INSTALLATIONS - SOLID STATE
SMOOTH SURVIVOR CURVE



ROCKLAND ELECTRIC COMPANY
ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES
ORIGINAL AND SMOOTH SURVIVOR CURVES



ROCKLAND ELECTRIC COMPANY

ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1928-2009 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	1,189,398		0.0000	1.0000	100.00
0.5	1,189,398		0.0000	1.0000	100.00
1.5	1,189,398		0.0000	1.0000	100.00
2.5	1,190,843		0.0000	1.0000	100.00
3.5	1,190,843	44,453	0.0373	0.9627	100.00
4.5	1,146,390	2,867	0.0025	0.9975	96.27
5.5	1,143,523	13,963	0.0122	0.9878	96.03
6.5	1,129,560	8,909	0.0079	0.9921	94.85
7.5	1,080,576	5,359	0.0050	0.9950	94.11
8.5	1,075,217	5,290	0.0049	0.9951	93.64
9.5	1,069,927		0.0000	1.0000	93.18
10.5	1,060,483		0.0000	1.0000	93.18
11.5	633,745		0.0000	1.0000	93.18
12.5	633,744		0.0000	1.0000	93.18
13.5	590,792		0.0000	1.0000	93.18
14.5	500,522		0.0000	1.0000	93.18
15.5	500,522		0.0000	1.0000	93.18
16.5	215,528	65	0.0003	0.9997	93.18
17.5	148,867	9	0.0001	0.9999	93.15
18.5	148,868		0.0000	1.0000	93.14
19.5	148,868		0.0000	1.0000	93.14
20.5	148,868		0.0000	1.0000	93.14
21.5	149,061		0.0000	1.0000	93.14
22.5	150,943	7,001	0.0464	0.9536	93.14
23.5	143,997	12	0.0001	0.9999	88.82
24.5	143,985		0.0000	1.0000	88.82
25.5	143,985		0.0000	1.0000	88.82
26.5	85,523	1,445	0.0169	0.9831	88.82
27.5	84,078		0.0000	1.0000	87.32
28.5	84,078		0.0000	1.0000	87.32
29.5	84,078		0.0000	1.0000	87.32
30.5	2,327		0.0000	1.0000	87.32
31.5	2,327		0.0000	1.0000	87.32
32.5	2,327		0.0000	1.0000	87.32
33.5	2,327		0.0000	1.0000	87.32
34.5	2,327		0.0000	1.0000	87.32
35.5	2,327		0.0000	1.0000	87.32
36.5	2,327		0.0000	1.0000	87.32
37.5	2,327		0.0000	1.0000	87.32
38.5	2,327	127	0.0546	0.9454	87.32

ROCKLAND ELECTRIC COMPANY

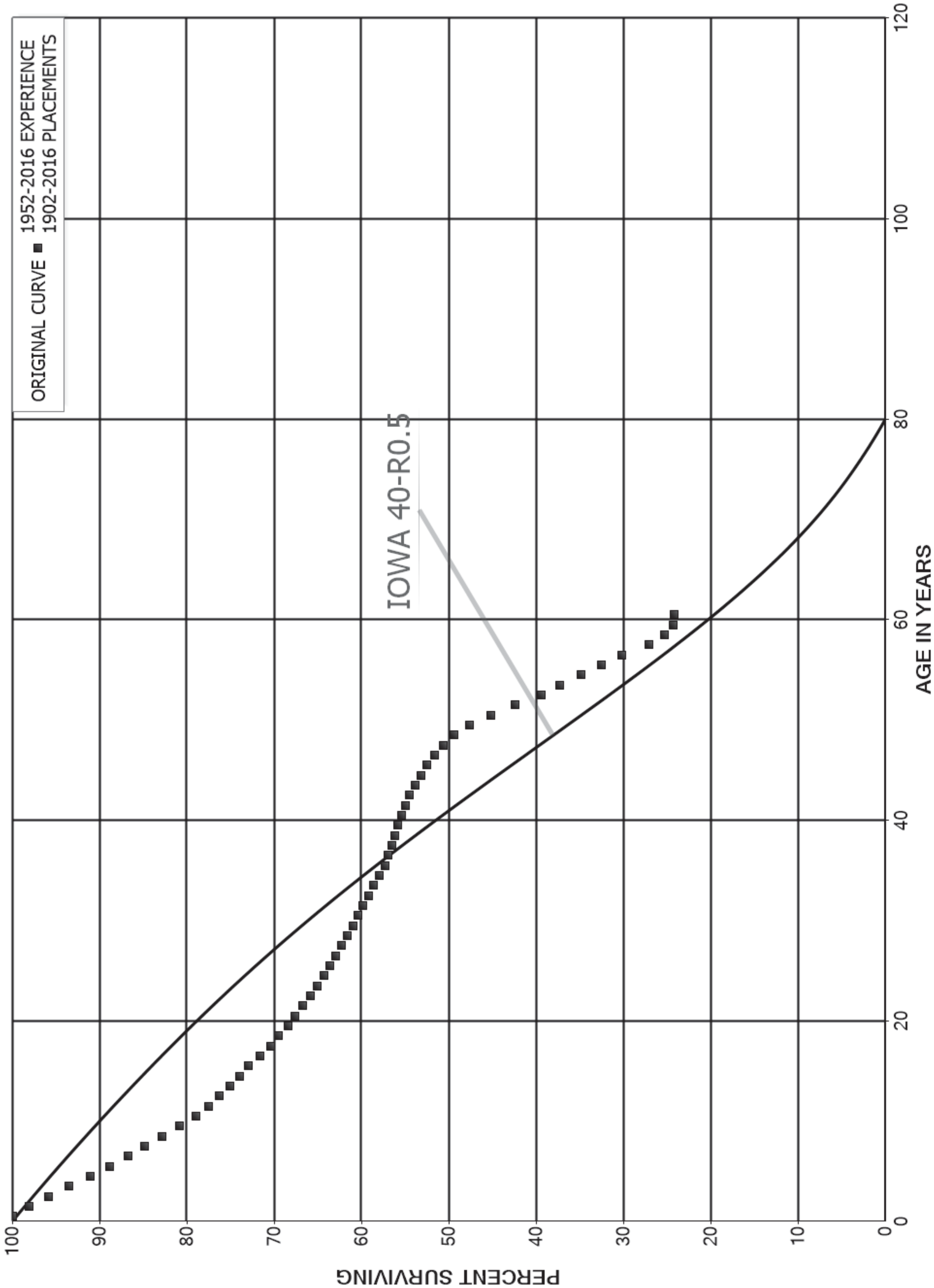
ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1928-2009 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	2,200		0.0000	1.0000	82.55
40.5	2,200		0.0000	1.0000	82.55
41.5	2,200	60	0.0273	0.9727	82.55
42.5	2,140		0.0000	1.0000	80.30
43.5	2,140		0.0000	1.0000	80.30
44.5	2,140		0.0000	1.0000	80.30
45.5	2,140		0.0000	1.0000	80.30
46.5	2,140	1,644	0.7682	0.2318	80.30
47.5	496		0.0000	1.0000	18.61
48.5	496		0.0000	1.0000	18.61
49.5	496		0.0000	1.0000	18.61
50.5	496		0.0000	1.0000	18.61
51.5	496		0.0000	1.0000	18.61
52.5	496		0.0000	1.0000	18.61
53.5	496		0.0000	1.0000	18.61
54.5	496		0.0000	1.0000	18.61
55.5	496		0.0000	1.0000	18.61
56.5	496		0.0000	1.0000	18.61
57.5	496		0.0000	1.0000	18.61
58.5	496		0.0000	1.0000	18.61
59.5	496		0.0000	1.0000	18.61
60.5	496		0.0000	1.0000	18.61
61.5	496		0.0000	1.0000	18.61
62.5	496		0.0000	1.0000	18.61
63.5	496		0.0000	1.0000	18.61
64.5	496		0.0000	1.0000	18.61
65.5	496		0.0000	1.0000	18.61
66.5	496		0.0000	1.0000	18.61
67.5	496		0.0000	1.0000	18.61
68.5	496		0.0000	1.0000	18.61
69.5	496		0.0000	1.0000	18.61
70.5	496		0.0000	1.0000	18.61
71.5	496	10	0.0202	0.9798	18.61
72.5	486		0.0000	1.0000	18.24
73.5	486		0.0000	1.0000	18.24
74.5	486	193	0.3971	0.6029	18.24
75.5	293	238	0.8123	0.1877	10.99
76.5	55	55	1.0000		2.06
77.5					

ROCKLAND ELECTRIC COMPANY
ACCOUNTS 373.10 AND 373.20 STREET LIGHTING AND SIGNAL SYSTEMS
ORIGINAL AND SMOOTH SURVIVOR CURVES



ROCKLAND ELECTRIC COMPANY

ACCOUNTS 373.10 AND 373.20 STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1902-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	31,190,831	13,814	0.0004	0.9996	100.00
0.5	29,637,844	563,302	0.0190	0.9810	99.96
1.5	27,365,798	622,299	0.0227	0.9773	98.06
2.5	25,751,123	620,262	0.0241	0.9759	95.83
3.5	23,742,343	612,548	0.0258	0.9742	93.52
4.5	22,256,591	555,522	0.0250	0.9750	91.11
5.5	21,220,373	508,800	0.0240	0.9760	88.83
6.5	20,292,401	436,062	0.0215	0.9785	86.70
7.5	19,544,882	470,738	0.0241	0.9759	84.84
8.5	18,699,567	442,048	0.0236	0.9764	82.79
9.5	17,942,169	415,671	0.0232	0.9768	80.84
10.5	17,207,025	314,609	0.0183	0.9817	78.96
11.5	16,629,203	272,175	0.0164	0.9836	77.52
12.5	16,110,516	249,064	0.0155	0.9845	76.25
13.5	15,710,427	235,332	0.0150	0.9850	75.07
14.5	15,171,222	214,316	0.0141	0.9859	73.95
15.5	14,665,174	259,297	0.0177	0.9823	72.90
16.5	13,939,736	240,246	0.0172	0.9828	71.62
17.5	13,312,320	173,922	0.0131	0.9869	70.38
18.5	12,808,920	196,477	0.0153	0.9847	69.46
19.5	12,322,433	136,083	0.0110	0.9890	68.40
20.5	11,999,612	158,029	0.0132	0.9868	67.64
21.5	11,449,402	148,708	0.0130	0.9870	66.75
22.5	10,843,582	126,658	0.0117	0.9883	65.88
23.5	10,263,194	126,177	0.0123	0.9877	65.11
24.5	9,769,137	108,109	0.0111	0.9889	64.31
25.5	9,080,701	95,025	0.0105	0.9895	63.60
26.5	8,449,581	84,846	0.0100	0.9900	62.94
27.5	7,845,646	88,386	0.0113	0.9887	62.30
28.5	7,341,445	79,589	0.0108	0.9892	61.60
29.5	7,039,296	67,117	0.0095	0.9905	60.93
30.5	6,559,661	60,906	0.0093	0.9907	60.35
31.5	6,181,290	68,389	0.0111	0.9889	59.79
32.5	5,742,666	51,767	0.0090	0.9910	59.13
33.5	5,421,971	60,015	0.0111	0.9889	58.60
34.5	5,087,973	55,775	0.0110	0.9890	57.95
35.5	4,756,640	34,398	0.0072	0.9928	57.31
36.5	4,433,826	29,293	0.0066	0.9934	56.90
37.5	4,179,590	25,523	0.0061	0.9939	56.52
38.5	3,898,208	26,540	0.0068	0.9932	56.18

ROCKLAND ELECTRIC COMPANY

ACCOUNTS 373.10 AND 373.20 STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1902-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	3,633,094	27,360	0.0075	0.9925	55.80
40.5	3,513,657	25,679	0.0073	0.9927	55.38
41.5	3,319,861	25,797	0.0078	0.9922	54.97
42.5	3,107,347	41,450	0.0133	0.9867	54.54
43.5	2,833,627	31,485	0.0111	0.9889	53.82
44.5	2,514,013	34,779	0.0138	0.9862	53.22
45.5	2,208,512	37,485	0.0170	0.9830	52.48
46.5	1,844,379	35,014	0.0190	0.9810	51.59
47.5	1,627,441	37,844	0.0233	0.9767	50.61
48.5	1,437,376	52,545	0.0366	0.9634	49.44
49.5	1,111,874	57,974	0.0521	0.9479	47.63
50.5	727,025	44,967	0.0619	0.9381	45.14
51.5	404,016	28,517	0.0706	0.9294	42.35
52.5	348,234	18,667	0.0536	0.9464	39.36
53.5	300,956	19,766	0.0657	0.9343	37.25
54.5	256,631	16,746	0.0653	0.9347	34.81
55.5	218,531	15,634	0.0715	0.9285	32.54
56.5	178,169	18,556	0.1041	0.8959	30.21
57.5	149,751	10,112	0.0675	0.9325	27.06
58.5	127,086	4,958	0.0390	0.9610	25.23
59.5	112,821	440	0.0039	0.9961	24.25
60.5	68,424	731	0.0107	0.9893	24.16
61.5	15,609	305	0.0195	0.9805	23.90
62.5	11,220	405	0.0361	0.9639	23.43
63.5	9,693	72	0.0074	0.9926	22.58
64.5	9,484	2,305	0.2431	0.7569	22.42
65.5	7,179	160	0.0223	0.9777	16.97
66.5	6,860		0.0000	1.0000	16.59
67.5	6,860	64	0.0093	0.9907	16.59
68.5	6,796	1,140	0.1677	0.8323	16.43
69.5	5,656	73	0.0129	0.9871	13.68
70.5	5,583	145	0.0259	0.9741	13.50
71.5	5,439	674	0.1239	0.8761	13.15
72.5	4,765	274	0.0576	0.9424	11.52
73.5	4,490		0.0000	1.0000	10.86
74.5	3,697	473	0.1280	0.8720	10.86
75.5	2,724	16	0.0058	0.9942	9.47
76.5	1,145	30	0.0262	0.9738	9.41
77.5	503	20	0.0406	0.9594	9.17
78.5	483	32	0.0660	0.9340	8.80

ROCKLAND ELECTRIC COMPANY

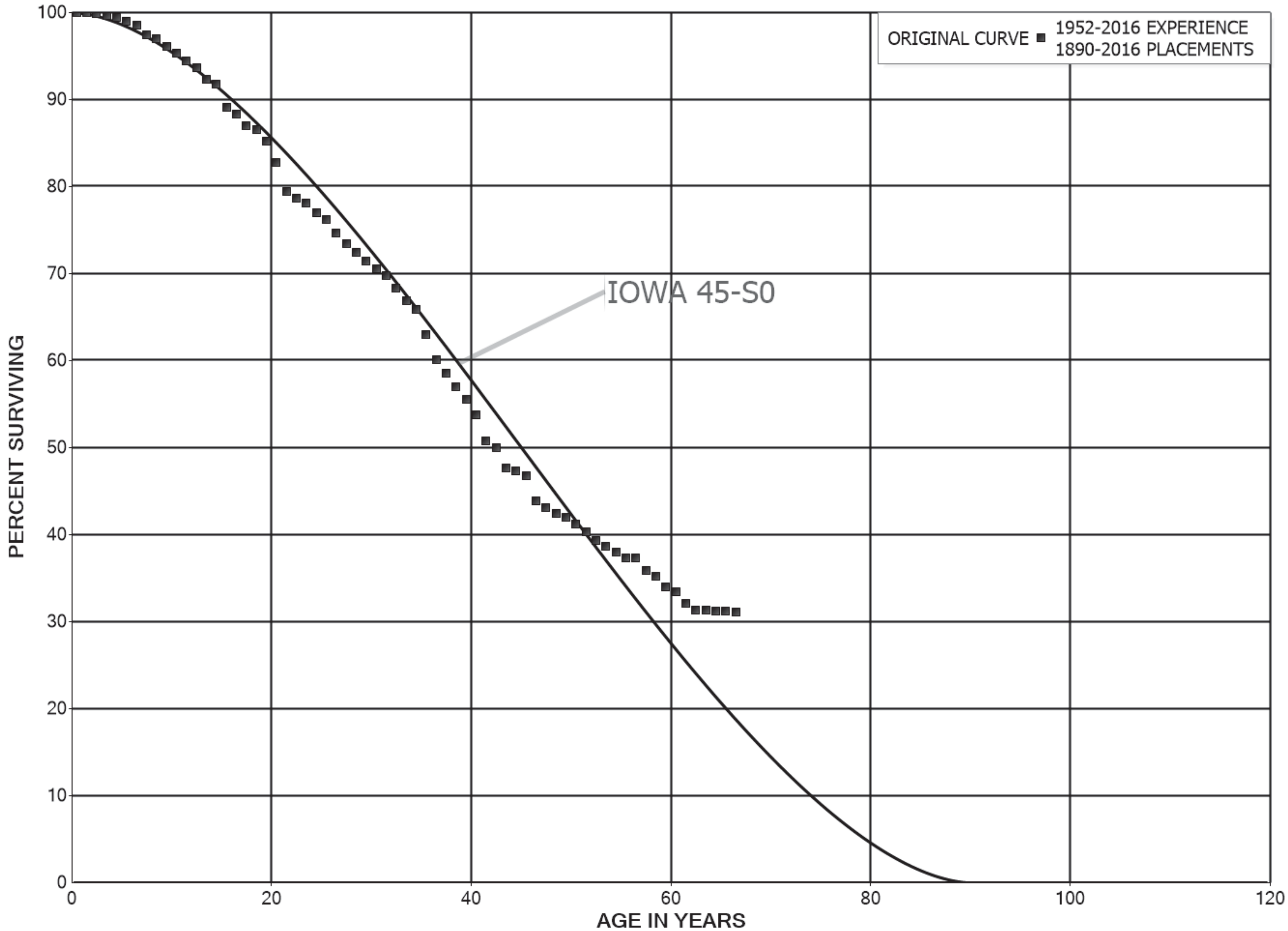
ACCOUNTS 373.10 AND 373.20 STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1902-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	421		0.0000	1.0000	8.21
80.5	421	29	0.0683	0.9317	8.21
81.5	392		0.0000	1.0000	7.65
82.5	392	144	0.3663	0.6337	7.65
83.5	248	23	0.0927	0.9073	4.85
84.5	225		0.0000	1.0000	4.40
85.5	225	51	0.2275	0.7725	4.40
86.5	174		0.0000	1.0000	3.40
87.5	174	19	0.1099	0.8901	3.40
88.5	155	128	0.8280	0.1720	3.03
89.5	27	10	0.3820	0.6180	0.52
90.5	16		0.0000	1.0000	0.32
91.5	16	16	1.0000		0.32
92.5					

ROCKLAND ELECTRIC COMPANY
ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



ROCKLAND ELECTRIC COMPANY

ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1890-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
0.0	97,906,668	949	0.0000	1.0000	100.00
0.5	97,151,632	34,205	0.0004	0.9996	100.00
1.5	86,855,809	90,908	0.0010	0.9990	99.96
2.5	74,619,699	177,005	0.0024	0.9976	99.86
3.5	73,881,647	178,290	0.0024	0.9976	99.62
4.5	73,099,096	336,559	0.0046	0.9954	99.38
5.5	71,393,218	296,939	0.0042	0.9958	98.92
6.5	68,612,526	803,460	0.0117	0.9883	98.51
7.5	63,812,609	279,239	0.0044	0.9956	97.36
8.5	58,786,322	515,183	0.0088	0.9912	96.93
9.5	51,710,314	407,142	0.0079	0.9921	96.08
10.5	49,853,623	514,886	0.0103	0.9897	95.33
11.5	48,039,059	348,251	0.0072	0.9928	94.34
12.5	44,660,036	638,730	0.0143	0.9857	93.66
13.5	42,470,946	259,361	0.0061	0.9939	92.32
14.5	37,103,190	1,090,386	0.0294	0.9706	91.76
15.5	34,528,116	292,541	0.0085	0.9915	89.06
16.5	33,973,479	511,732	0.0151	0.9849	88.30
17.5	33,169,990	168,553	0.0051	0.9949	86.97
18.5	32,770,199	502,427	0.0153	0.9847	86.53
19.5	31,774,245	908,898	0.0286	0.9714	85.21
20.5	29,790,579	1,198,362	0.0402	0.9598	82.77
21.5	28,619,412	312,922	0.0109	0.9891	79.44
22.5	27,648,545	175,640	0.0064	0.9936	78.57
23.5	27,168,649	405,175	0.0149	0.9851	78.07
24.5	26,294,789	232,036	0.0088	0.9912	76.91
25.5	25,889,346	535,463	0.0207	0.9793	76.23
26.5	25,350,659	411,893	0.0162	0.9838	74.65
27.5	24,628,926	333,574	0.0135	0.9865	73.44
28.5	23,237,225	339,240	0.0146	0.9854	72.44
29.5	22,774,581	294,023	0.0129	0.9871	71.39
30.5	22,381,643	231,674	0.0104	0.9896	70.46
31.5	21,787,925	440,173	0.0202	0.9798	69.74
32.5	13,483,941	300,898	0.0223	0.9777	68.33
33.5	11,629,341	164,870	0.0142	0.9858	66.80
34.5	10,610,815	470,144	0.0443	0.9557	65.85
35.5	9,669,976	440,886	0.0456	0.9544	62.94
36.5	9,092,857	233,786	0.0257	0.9743	60.07
37.5	6,538,477	176,877	0.0271	0.9729	58.52
38.5	5,701,410	140,483	0.0246	0.9754	56.94

ROCKLAND ELECTRIC COMPANY

ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1890-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
39.5	5,541,048	180,412	0.0326	0.9674	55.54
40.5	5,351,599	301,297	0.0563	0.9437	53.73
41.5	4,983,126	70,114	0.0141	0.9859	50.70
42.5	4,639,403	219,495	0.0473	0.9527	49.99
43.5	4,398,079	29,858	0.0068	0.9932	47.63
44.5	4,325,996	55,728	0.0129	0.9871	47.30
45.5	4,251,362	257,576	0.0606	0.9394	46.69
46.5	3,976,249	74,986	0.0189	0.9811	43.86
47.5	2,791,919	45,147	0.0162	0.9838	43.04
48.5	2,687,979	25,538	0.0095	0.9905	42.34
49.5	1,648,602	28,875	0.0175	0.9825	41.94
50.5	1,208,426	26,999	0.0223	0.9777	41.20
51.5	1,086,540	25,785	0.0237	0.9763	40.28
52.5	1,052,324	19,391	0.0184	0.9816	39.33
53.5	1,025,592	18,892	0.0184	0.9816	38.60
54.5	1,003,174	15,557	0.0155	0.9845	37.89
55.5	981,899	1,093	0.0011	0.9989	37.30
56.5	895,410	33,311	0.0372	0.9628	37.26
57.5	861,556	17,156	0.0199	0.9801	35.88
58.5	847,526	27,877	0.0329	0.9671	35.16
59.5	773,499	13,165	0.0170	0.9830	34.01
60.5	764,360	31,044	0.0406	0.9594	33.43
61.5	734,722	17,301	0.0235	0.9765	32.07
62.5	714,489	1,870	0.0026	0.9974	31.31
63.5	691,394	1,416	0.0020	0.9980	31.23
64.5	688,984	930	0.0013	0.9987	31.17
65.5	675,345	934	0.0014	0.9986	31.13
66.5	368,669	14,029	0.0381	0.9619	31.08
67.5	354,640	3,013	0.0085	0.9915	29.90
68.5	351,627	7,038	0.0200	0.9800	29.65
69.5	344,588	2,832	0.0082	0.9918	29.05
70.5	341,536	536	0.0016	0.9984	28.81
71.5	340,968	67,649	0.1984	0.8016	28.77
72.5	272,871	1,398	0.0051	0.9949	23.06
73.5	271,473	2,709	0.0100	0.9900	22.94
74.5	268,751	2,565	0.0095	0.9905	22.71
75.5	265,489	465	0.0018	0.9982	22.50
76.5	264,973	1,630	0.0062	0.9938	22.46
77.5	263,258	1,876	0.0071	0.9929	22.32
78.5	261,120	288	0.0011	0.9989	22.16

ROCKLAND ELECTRIC COMPANY

ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1890-2016 EXPERIENCE BAND 1952-2016

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
79.5	260,807	1,305	0.0050	0.9950	22.14
80.5	259,414	511	0.0020	0.9980	22.02
81.5	258,863		0.0000	1.0000	21.98
82.5	258,709	1,271	0.0049	0.9951	21.98
83.5	257,273		0.0000	1.0000	21.87
84.5	257,273		0.0000	1.0000	21.87
85.5	257,273	1,953	0.0076	0.9924	21.87
86.5	166,253	123	0.0007	0.9993	21.71
87.5	166,099	25	0.0002	0.9998	21.69
88.5	107,818	1,640	0.0152	0.9848	21.69
89.5	96,535	20,892	0.2164	0.7836	21.36
90.5	51,217		0.0000	1.0000	16.74
91.5	22,789		0.0000	1.0000	16.74
92.5	16,468	34	0.0021	0.9979	16.74
93.5	7,021		0.0000	1.0000	16.70
94.5	7,021		0.0000	1.0000	16.70
95.5	6,282		0.0000	1.0000	16.70
96.5	6,282		0.0000	1.0000	16.70
97.5	6,226	25	0.0040	0.9960	16.70
98.5	5,957		0.0000	1.0000	16.63
99.5	5,957		0.0000	1.0000	16.63
100.5	5,957		0.0000	1.0000	16.63
101.5	5,957		0.0000	1.0000	16.63
102.5	2,555		0.0000	1.0000	16.63
103.5	2,555		0.0000	1.0000	16.63
104.5	2,555		0.0000	1.0000	16.63
105.5	2,555		0.0000	1.0000	16.63
106.5	2,555		0.0000	1.0000	16.63
107.5					16.63

PART VIII. DETAILED DEPRECIATION CALCULATIONS

ROCKLAND ELECTRIC COMPANY

ACCOUNT 352.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R2						
1959	15,127.51	10,761	11,651	3,477	17.32	201
1962	226.58	155	168	59	18.84	3
1965	3,575.67	2,358	2,553	1,023	20.44	50
1968	74,586.29	47,064	50,955	23,631	22.14	1,067
1969	6,788.31	4,218	4,567	2,221	22.72	98
1971	1,323.42	796	862	461	23.92	19
1972	8,695.78	5,141	5,566	3,130	24.53	128
1975	176,410.68	98,760	106,925	69,486	26.41	2,631
1977	12,118.06	6,522	7,061	5,057	27.71	182
1981	20,815.75	10,262	11,110	9,706	30.42	319
1982	142.34	69	75	67	31.11	2
1992	60,327.52	21,647	23,437	36,891	38.47	959
1997	720.04	211	228	492	42.41	12
1999	330,664.26	88,066	95,347	235,317	44.02	5,346
2002	525,372.92	118,298	128,078	397,295	46.49	8,546
2004	509,925.55	100,542	108,855	401,071	48.17	8,326
2005	20,047.16	3,672	3,976	16,071	49.01	328
2007	48,479.09	7,498	8,118	40,361	50.72	796
2008	57,448.57	8,062	8,728	48,721	51.58	945
2010	29,908.24	3,330	3,605	26,303	53.32	493
2013	1,808.73	122	132	1,677	55.96	30
2016	57,033.56	1,293	1,400	55,633	58.64	949
	1,961,546.03	538,847	583,397	1,378,149		31,430

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 43.8   1.60

ROCKLAND ELECTRIC COMPANY

ACCOUNT 353.00 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-S0						
1957	47,432.58	35,522	32,135	15,298	11.30	1,354
1959	188,351.03	137,664	124,537	63,814	12.11	5,270
1962	6,382.24	4,487	4,059	2,323	13.36	174
1964	4,783.77	3,274	2,962	1,822	14.20	128
1965	85,975.64	58,043	52,508	33,468	14.62	2,289
1967	9,455.98	6,203	5,612	3,844	15.48	248
1968	319,262.24	206,384	186,704	132,558	15.91	8,332
1969	86,130.09	54,836	49,607	36,523	16.35	2,234
1970	17,447.50	10,942	9,899	7,548	16.78	450
1971	152,522.21	94,157	85,178	67,344	17.22	3,911
1972	656,859.55	398,931	360,890	295,970	17.67	16,750
1973	104,168.57	62,223	56,290	47,879	18.12	2,642
1974	3,196.32	1,877	1,698	1,498	18.57	81
1975	1,215,967.36	702,014	635,072	580,895	19.02	30,541
1976	365,922.74	207,518	187,730	178,193	19.48	9,147
1977	24,817.34	13,821	12,503	12,314	19.94	618
1978	487.44	266	241	246	20.40	12
1980	197,750.23	103,930	94,020	103,730	21.35	4,859
1984	53,081.41	25,621	23,178	29,903	23.28	1,284
1985	215,423.12	101,585	91,898	123,525	23.78	5,194
1986	242,786.11	111,788	101,128	141,658	24.28	5,834
1987	23,400.16	10,514	9,511	13,889	24.78	560
1988	31,505.01	13,792	12,477	19,028	25.30	752
1989	9,184.71	3,917	3,543	5,642	25.81	219
1990	70,257.91	29,134	26,356	43,902	26.34	1,667
1991	1,754,390.26	706,826	639,425	1,114,965	26.87	41,495
1992	554,502.18	216,871	196,191	358,311	27.40	13,077
1993	138,607.15	52,517	47,509	91,098	27.95	3,259
1994	110,287.18	40,439	36,583	73,704	28.50	2,586
1995	67,630.73	23,971	21,685	45,946	29.05	1,582
1996	18,618.68	6,363	5,756	12,863	29.62	434
1997	3,521.78	1,159	1,048	2,474	30.19	82
1998	10,517.46	3,324	3,007	7,510	30.78	244
2000	869,575.23	251,794	227,784	641,791	31.97	20,075
2002	71,001.18	18,618	16,843	54,158	33.20	1,631
2003	12,777.80	3,169	2,867	9,911	33.84	293
2004	2,717,597.98	635,320	574,738	2,142,860	34.48	62,148
2005	202,856.42	44,448	40,210	162,646	35.14	4,629
2006	525,471.94	107,312	97,079	428,393	35.81	11,963
2007	755,330.20	142,674	129,069	626,261	36.50	17,158
2008	993,978.96	172,286	155,857	838,122	37.20	22,530
2009	280,813.86	44,180	39,967	240,847	37.92	6,351
2010	13,541.92	1,908	1,726	11,816	38.66	306
2011	106,922.88	13,258	11,994	94,929	39.42	2,408

ROCKLAND ELECTRIC COMPANY

ACCOUNT 353.00 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-S0						
2012	204,904.45	21,902	19,813	185,091	40.19	4,605
2013	52,354.84	4,654	4,210	48,145	41.00	1,174
2014	2,362.86	166	150	2,213	41.83	53
2015	178,135.55	9,185	8,309	169,827	42.68	3,979
2016	81,252.09	2,564	2,320	78,932	43.58	1,811
2017	200,227.27	2,180	1,972	198,255	44.51	4,454
	14,059,732.11	4,925,531	4,455,848	9,603,884		332,877

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 28.9 2.37

ROCKLAND ELECTRIC COMPANY

ACCOUNT 354.00 TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 70-R4						
1930	21,919.41	20,535	11,597	10,322	4.42	2,335
1931	39.89	37	21	19	4.69	4
1934	578,010.83	532,516	300,728	277,283	5.51	50,324
1939	12.03	11	6	6	6.99	1
1953	130,808.41	106,235	59,994	70,814	13.15	5,385
1955	1,084.42	862	487	597	14.38	42
1956	18,955.34	14,888	8,408	10,547	15.02	702
1966	276,932.68	189,779	107,173	169,760	22.03	7,706
1968	32,524.00	21,582	12,188	20,336	23.55	864
1969	56,991.98	37,183	20,998	35,994	24.33	1,479
1978	25,527.14	13,923	7,863	17,664	31.82	555
1979	1,009.15	538	304	705	32.70	22
1980	34,728.82	18,064	10,201	24,528	33.59	730
1995	6,092.67	1,943	1,098	4,995	47.68	105
2014	67.60	3	1	66	66.50	1
	1,184,704.37	958,099	541,067	643,637		70,255

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 9.2 5.93

ROCKLAND ELECTRIC COMPANY

ACCOUNT 355.00 POLES AND FIXTURES - WOOD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R3						
1958	9,488.62	7,908	8,208	1,281	9.16	140
1962	71,950.81	57,744	59,938	12,013	10.86	1,106
1963	5,720.46	4,542	4,715	1,005	11.33	89
1964	213.46	168	174	39	11.82	3
1966	2,019.13	1,547	1,606	413	12.85	32
1968	138,281.18	103,234	107,157	31,124	13.94	2,233
1969	75,416.35	55,520	57,630	17,786	14.51	1,226
1971	303,131.81	216,545	224,773	78,359	15.71	4,988
1972	52,687.44	37,053	38,461	14,226	16.32	872
1974	3,100.90	2,108	2,188	913	17.61	52
1975	16,564.89	11,062	11,482	5,083	18.27	278
1976	34,600.70	22,686	23,548	11,053	18.94	584
1977	345.44	222	230	115	19.63	6
1978	371,116.46	233,937	242,826	128,290	20.33	6,310
1979	114,828.03	70,901	73,595	41,233	21.04	1,960
1988	4,076.15	2,005	2,081	1,995	27.94	71
1989	2,898.81	1,383	1,436	1,463	28.76	51
1990	23,795.54	10,994	11,412	12,384	29.59	419
1991	16,960.19	7,580	7,868	9,092	30.42	299
1996	150.93	56	58	93	34.72	3
1997	46,936.15	16,556	17,185	29,751	35.60	836
1999	1,792.56	574	596	1,197	37.39	32
2003	32,812.60	8,316	8,632	24,181	41.06	589
2004	145,383.22	34,390	35,697	109,686	41.99	2,612
2005	16,125.45	3,539	3,673	12,452	42.93	290
2006	984,477.78	199,219	206,789	777,689	43.87	17,727
2008	29,671.71	4,980	5,169	24,503	45.77	535
2010	48,482.87	6,444	6,689	41,794	47.69	876
2011	234,847.58	27,113	28,143	206,705	48.65	4,249
2013	773,103.86	61,987	64,343	708,761	50.59	14,010
2014	88,339.48	5,509	5,718	82,621	51.57	1,602
2015	93,165.04	4,167	4,325	88,840	52.54	1,691
2016	698,545.37	18,798	19,513	679,032	53.52	12,687
2017	33,648.71	300	311	33,337	54.51	612
	4,474,679.68	1,239,087	1,286,169	3,188,510		79,070

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 40.3   1.77

ROCKLAND ELECTRIC COMPANY

ACCOUNT 355.10 POLES AND FIXTURES - STEEL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R3						
1968	9,552.90	7,132	6,489	3,064	13.94	220
1972	50,093.09	35,229	32,051	18,042	16.32	1,106
1974	145,688.71	99,042	90,107	55,582	17.61	3,156
1992	55,009.04	23,744	21,602	33,407	31.26	1,069
2006	573,374.38	116,028	105,560	467,814	43.87	10,664
2007	82,606.07	15,304	13,924	68,682	44.81	1,533
	916,324.19	296,479	269,733	646,592		17,748

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 36.4 1.94

ROCKLAND ELECTRIC COMPANY

ACCOUNT 356.00 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R1.5						
1931	11,815.66	9,538	11,412	404	12.53	32
1945	68.23	50	60	8	17.60	
1958	7,476.56	4,762	5,697	1,780	23.60	75
1961	199.23	122	146	53	25.18	2
1962	61,124.28	36,938	44,194	16,930	25.72	658
1963	4,375.79	2,607	3,119	1,257	26.27	48
1966	91,780.50	52,301	62,575	29,206	27.96	1,045
1967	25,145.68	14,105	16,876	8,270	28.54	290
1968	140,398.96	77,479	92,700	47,699	29.13	1,637
1969	113,940.51	61,843	73,992	39,949	29.72	1,344
1971	188,788.92	98,954	118,393	70,396	30.93	2,276
1972	215,066.47	110,678	132,421	82,645	31.55	2,619
1974	69,497.66	34,428	41,191	28,307	32.80	863
1975	1,013.82	492	589	425	33.43	13
1976	157,519.19	74,930	89,650	67,869	34.08	1,991
1977	1,833.32	854	1,022	811	34.72	23
1978	285,241.16	129,982	155,517	129,724	35.38	3,667
1979	77,383.22	34,477	41,250	36,133	36.04	1,003
1980	1,114.22	485	580	534	36.71	15
1982	426,583.89	176,802	211,534	215,050	38.06	5,650
1992	28,518.92	8,718	10,431	18,088	45.13	401
2006	1,356,485.71	193,245	231,208	1,125,278	55.74	20,188
2007	72,417.60	9,437	11,291	61,127	56.53	1,081
2015	6,172.28	195	233	5,939	62.95	94
2016	623,372.77	11,794	14,111	609,262	63.77	9,554
2017	62,688.47	396	474	62,215	64.59	963
	4,030,023.02	1,145,612	1,370,666	2,659,357		55,532

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 47.9 1.38

ROCKLAND ELECTRIC COMPANY

ACCOUNT 356.10 OVERHEAD CONDUCTORS AND DEVICES - CLEARING

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R1.5						
1924	420.57	353	316	105	10.38	10
1928	498.50	410	367	132	11.58	11
1931	5,715.92	4,614	4,129	1,587	12.53	127
1941	151.22	114	102	49	16.02	3
1959	9,727.50	6,118	5,475	4,252	24.12	176
1961	16,825.02	10,307	9,225	7,600	25.18	302
1965	4,186.72	2,423	2,169	2,018	27.39	74
1966	1,861.82	1,061	950	912	27.96	33
1967	10,865.47	6,095	5,455	5,410	28.54	190
1968	52,806.47	29,141	26,080	26,726	29.13	917
1971	103,447.01	54,222	48,527	54,920	30.93	1,776
1974	2,190.39	1,085	971	1,219	32.80	37
1982	17,916.80	7,426	6,646	11,271	38.06	296
2008	171,379.00	20,248	18,122	153,257	57.32	2,674
	397,992.41	143,617	128,534	269,458		6,626

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 40.7   1.66

ROCKLAND ELECTRIC COMPANY

ACCOUNT 357.00 UNDERGROUND CONDUIT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-R3						
1972	7,382.36	5,930	6,799	583	8.85	66
2003	1,109,346.47	340,935	390,918	718,428	31.17	23,049
	1,116,728.83	346,865	397,717	719,012		23,115

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 31.1   2.07

ROCKLAND ELECTRIC COMPANY

ACCOUNT 358.00 UNDERGROUND CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 35-S3						
1972	16,654.46	14,841	15,495	1,159	3.81	304
1992	32,493.77	21,631	22,585	9,909	11.70	847
1999	51,736.83	26,622	27,796	23,941	16.99	1,409
2002	46,154.26	20,189	21,079	25,075	19.69	1,273
2003	925,969.93	380,175	396,939	529,031	20.63	25,644
2014	1,711.61	171	178	1,533	31.50	49
	1,074,720.86	463,629	484,072	590,649		29,526

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 20.0 2.75

ROCKLAND ELECTRIC COMPANY

ACCOUNT 359.00 ROADS AND TRAILS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R4						
1974	10,154.70	6,435	6,989	3,166	23.81	133
1978	28,532.59	16,628	18,061	10,472	27.12	386
1979	38,063.74	21,685	23,553	14,511	27.97	519
2017	19,991.22	154	167	19,824	64.50	307
	96,742.25	44,902	48,770	47,972		1,345

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 35.7 1.39

ROCKLAND ELECTRIC COMPANY

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R3						
1952	6,130.69	5,344	4,898	1,233	7.06	175
1954	106.00	91	83	23	7.70	3
1955	37,761.13	32,241	29,547	8,214	8.04	1,022
1957	171.68	144	132	40	8.77	5
1958	449.90	375	344	106	9.16	12
1963	2,059.38	1,635	1,498	561	11.33	50
1964	46,475.04	36,487	33,439	13,036	11.82	1,103
1965	1,134.09	880	806	328	12.33	27
1967	3,098.03	2,344	2,148	950	13.39	71
1968	51,885.59	38,735	35,499	16,387	13.94	1,176
1971	13,730.38	9,808	8,989	4,741	15.71	302
1972	178,162.97	125,297	114,829	63,334	16.32	3,881
1973	207.56	144	132	76	16.96	4
1974	29,300.76	19,919	18,255	11,046	17.61	627
1975	5,465.07	3,650	3,345	2,120	18.27	116
1976	102,771.96	67,381	61,751	41,021	18.94	2,166
1981	27,154.43	16,046	14,705	12,449	22.50	553
1982	8,422.42	4,862	4,456	3,966	23.25	171
1984	230.36	127	116	114	24.77	5
1985	60,539.92	32,416	29,708	30,832	25.55	1,207
1986	3,644.54	1,899	1,740	1,905	26.34	72
1988	40,211.39	19,784	18,131	22,080	27.94	790
1989	95,534.37	45,578	41,770	53,764	28.76	1,869
1991	573,614.74	256,354	234,936	338,679	30.42	11,133
1992	51,851.89	22,381	20,511	31,341	31.26	1,003
1993	29,532.20	12,291	11,264	18,268	32.11	569
1995	138,470.46	53,274	48,823	89,647	33.84	2,649
1996	1,759.00	649	595	1,164	34.72	34
1997	73,108.46	25,788	23,633	49,475	35.60	1,390
1998	3,492.78	1,175	1,077	2,416	36.49	66
1999	583.88	187	171	413	37.39	11
2000	21,106.89	6,409	5,874	15,233	38.30	398
2001	47,441.02	13,620	12,482	34,959	39.21	892
2003	126,091.74	31,958	29,288	96,804	41.06	2,358
2004	816,592.28	193,165	177,027	639,565	41.99	15,231
2005	100,096.66	21,966	20,131	79,966	42.93	1,863
2006	4,610.57	933	855	3,756	43.87	86
2007	407,355.43	75,471	69,165	338,190	44.81	7,547
2008	144,726.23	24,288	22,259	122,467	45.77	2,676
2009	217,136.67	32,690	29,959	187,178	46.72	4,006
2010	46,756.15	6,214	5,695	41,061	47.69	861
2011	173,717.68	20,056	18,380	155,338	48.65	3,193
2012	66,830.97	6,537	5,991	60,840	49.62	1,226
2013	577,207.66	46,281	42,414	534,794	50.59	10,571

ROCKLAND ELECTRIC COMPANY

ACCOUNT 361.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R3						
2015	18,355.41	821	752	17,603	52.54	335
2016	25,733.30	692	634	25,099	53.52	469
2017	225,363.21	2,008	1,841	223,522	54.51	4,101
	4,606,182.94	1,320,395	1,210,078	3,396,105		88,075

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 38.6 1.91

ROCKLAND ELECTRIC COMPANY

ACCOUNT 362.00 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-S0						
1930	3,144.53	3,080	2,802	343	0.92	343
1941	110.83	98	89	22	5.02	4
1942	851.35	749	682	169	5.40	31
1951	2,405.00	1,930	1,756	649	8.89	73
1954	10,245.56	7,951	7,235	3,011	10.08	299
1955	6,133.77	4,704	4,280	1,854	10.49	177
1956	869.34	659	600	269	10.89	25
1957	5,872.40	4,398	4,002	1,870	11.30	165
1959	116.79	85	77	40	12.11	3
1961	37,128.57	26,452	24,068	13,061	12.94	1,009
1962	286.78	202	184	103	13.36	8
1963	49,901.26	34,620	31,500	18,401	13.78	1,335
1964	69,913.42	47,852	43,540	26,373	14.20	1,857
1965	2,557.25	1,726	1,570	987	14.62	68
1966	538.79	359	327	212	15.05	14
1967	19,081.77	12,518	11,390	7,692	15.48	497
1968	153,402.74	99,166	90,230	63,173	15.91	3,971
1969	33,480.10	21,316	19,395	14,085	16.35	861
1970	1,327.41	832	757	570	16.78	34
1971	407,819.78	251,759	229,073	178,747	17.22	10,380
1972	993,855.06	603,598	549,209	444,646	17.67	25,164
1973	144,854.63	86,526	78,729	66,126	18.12	3,649
1974	235,889.93	138,545	126,061	109,829	18.57	5,914
1975	21,017.83	12,134	11,041	9,977	19.02	525
1976	1,593,098.54	903,462	822,053	771,046	19.48	39,581
1977	100,839.35	56,156	51,096	49,743	19.94	2,495
1978	333,905.01	182,536	166,088	167,817	20.40	8,226
1979	6,230.66	3,341	3,040	3,191	20.87	153
1981	1,305,486.71	672,469	611,874	693,613	21.82	31,788
1982	64,010.10	32,289	29,379	34,631	22.30	1,553
1983	26,348.71	13,005	11,833	14,516	22.79	637
1984	6,453.97	3,115	2,834	3,620	23.28	155
1985	310,379.41	146,363	133,175	177,204	23.78	7,452
1986	557,925.81	256,891	233,743	324,183	24.28	13,352
1987	210,542.98	94,603	86,079	124,464	24.78	5,023
1988	399,820.85	175,034	159,262	240,559	25.30	9,508
1989	51,371.26	21,907	19,933	31,438	25.81	1,218
1990	1,366,872.78	566,801	515,728	851,145	26.34	32,314
1991	2,472,784.31	996,260	906,489	1,566,295	26.87	58,292
1992	662,316.23	259,039	235,697	426,619	27.40	15,570
1993	229,897.55	87,106	79,257	150,641	27.95	5,390
1994	516,757.09	189,479	172,405	344,352	28.50	12,083
1995	187,375.06	66,413	60,429	126,946	29.05	4,370
1996	88,183.86	30,139	27,423	60,761	29.62	2,051

ROCKLAND ELECTRIC COMPANY

ACCOUNT 362.00 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-S0						
1997	2,626,034.85	864,254	786,378	1,839,657	30.19	60,936
1998	208,133.95	65,770	59,844	148,290	30.78	4,818
1999	609,119.41	184,496	167,871	441,248	31.37	14,066
2000	24,996.80	7,238	6,586	18,411	31.97	576
2001	154,623.12	42,676	38,831	115,792	32.58	3,554
2002	813,667.29	213,360	194,135	619,532	33.20	18,661
2003	3,404,258.00	844,256	768,181	2,636,077	33.84	77,898
2004	7,069,231.80	1,652,645	1,503,728	5,565,504	34.48	161,413
2005	421,581.64	92,373	84,049	337,533	35.14	9,605
2006	1,279,541.15	261,308	237,762	1,041,779	35.81	29,092
2007	3,793,327.35	716,522	651,958	3,141,369	36.50	86,065
2008	689,025.92	119,429	108,667	580,359	37.20	15,601
2009	1,559,994.47	245,434	223,318	1,336,676	37.92	35,250
2010	42,586.83	6,000	5,459	37,128	38.66	960
2011	207,927.39	25,783	23,460	184,467	39.42	4,680
2012	489,713.76	52,346	47,629	442,085	40.19	11,000
2013	4,253,969.95	378,135	344,062	3,909,908	41.00	95,364
2014	1,859,532.12	130,985	119,182	1,740,350	41.83	41,605
2015	225,665.84	11,635	10,587	215,079	42.68	5,039
2016	12,395,215.47	391,193	355,944	12,039,271	43.58	276,257
2017	89,572.28	975	887	88,685	44.51	1,992
	54,909,124.52	12,424,480	11,304,932	43,604,192		1,262,049

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 34.6   2.30

ROCKLAND ELECTRIC COMPANY

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R1						
1914	14.07	13	10	4	2.35	2
1925	42.19	38	29	13	5.72	2
1927	14.07	12	9	5	6.33	1
1929	402.67	352	267	136	6.96	20
1930	464.11	403	305	159	7.28	22
1931	51.05	44	33	18	7.60	2
1932	221.11	189	143	78	7.93	10
1933	1,172.54	996	755	418	8.26	51
1934	897.64	757	573	325	8.59	38
1935	792.44	664	503	289	8.93	32
1936	2,156.06	1,792	1,358	798	9.28	86
1937	1,739.35	1,435	1,087	652	9.63	68
1938	1,493.03	1,222	926	567	9.98	57
1939	2,619.52	2,127	1,611	1,009	10.34	98
1940	4,250.77	3,424	2,594	1,657	10.70	155
1941	3,209.64	2,564	1,942	1,268	11.06	115
1942	3,209.31	2,542	1,926	1,283	11.44	112
1943	2,232.44	1,753	1,328	904	11.81	77
1944	1,760.47	1,370	1,038	722	12.19	59
1945	2,540.19	1,959	1,484	1,056	12.58	84
1946	3,895.23	2,977	2,255	1,640	12.97	126
1947	5,110.33	3,868	2,930	2,180	13.37	163
1948	7,222.76	5,414	4,101	3,122	13.77	227
1949	7,675.30	5,698	4,317	3,358	14.17	237
1950	11,203.34	8,233	6,237	4,966	14.58	341
1951	20,887.65	15,191	11,508	9,380	15.00	625
1952	10,978.25	7,900	5,985	4,993	15.42	324
1953	56,887.91	40,494	30,676	26,212	15.85	1,654
1954	50,106.67	35,275	26,723	23,384	16.28	1,436
1955	40,639.01	28,285	21,427	19,212	16.72	1,149
1956	55,995.12	38,515	29,177	26,818	17.17	1,562
1957	84,754.07	57,602	43,636	41,118	17.62	2,334
1958	53,830.25	36,144	27,381	26,449	18.07	1,464
1959	50,921.57	33,766	25,579	25,343	18.53	1,368
1960	68,339.15	44,731	33,886	34,453	19.00	1,813
1961	76,477.20	49,391	37,416	39,061	19.48	2,005
1962	94,318.84	60,090	45,521	48,798	19.96	2,445
1963	94,388.52	59,310	44,930	49,459	20.44	2,420
1964	110,719.80	68,585	51,957	58,763	20.93	2,808
1965	108,249.67	66,071	50,052	58,198	21.43	2,716
1966	135,388.00	81,380	61,649	73,739	21.94	3,361
1967	114,872.71	67,984	51,501	63,372	22.45	2,823
1968	166,064.34	96,709	73,262	92,802	22.97	4,040
1969	144,240.34	82,637	62,602	81,638	23.49	3,475

ROCKLAND ELECTRIC COMPANY

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R1						
1970	332,019.30	187,017	141,675	190,344	24.02	7,924
1971	323,738.31	179,173	135,733	188,005	24.56	7,655
1972	617,852.37	335,889	254,453	363,399	25.10	14,478
1973	844,847.10	450,844	341,537	503,310	25.65	19,622
1974	533,095.41	279,150	211,470	321,625	26.20	12,276
1975	438,934.38	225,292	170,670	268,264	26.77	10,021
1976	244,767.42	123,140	93,285	151,482	27.33	5,543
1977	221,204.33	108,954	82,538	138,666	27.91	4,968
1978	301,453.70	145,301	110,073	191,381	28.49	6,717
1979	203,951.03	96,153	72,841	131,110	29.07	4,510
1980	363,407.60	167,367	126,789	236,619	29.67	7,975
1981	542,127.79	243,762	184,662	357,466	30.27	11,809
1982	311,046.13	136,465	103,379	207,667	30.87	6,727
1983	359,011.09	153,528	116,305	242,706	31.48	7,710
1984	302,699.10	126,032	95,476	207,223	32.10	6,456
1985	349,132.14	141,430	107,140	241,992	32.72	7,396
1986	316,264.40	124,551	94,354	221,910	33.34	6,656
1987	427,976.06	163,641	123,966	304,010	33.97	8,949
1988	566,010.89	209,837	158,962	407,049	34.61	11,761
1989	625,997.65	224,789	170,289	455,709	35.25	12,928
1990	847,652.27	294,364	222,996	624,656	35.90	17,400
1991	609,079.53	204,316	154,780	454,300	36.55	12,430
1992	463,337.46	149,955	113,598	349,739	37.20	9,402
1993	551,700.24	171,932	130,247	421,453	37.86	11,132
1994	378,725.35	113,481	85,968	292,757	38.52	7,600
1995	581,157.25	167,054	126,552	454,605	39.19	11,600
1996	798,406.93	219,777	166,492	631,915	39.86	15,853
1997	350,607.93	92,241	69,877	280,731	40.53	6,926
1998	372,042.44	93,282	70,666	301,376	41.21	7,313
1999	459,375.60	109,584	83,015	376,361	41.88	8,987
2000	518,411.72	117,161	88,755	429,657	42.57	10,093
2001	824,790.11	176,208	133,486	691,304	43.25	15,984
2002	574,571.05	115,540	87,527	487,044	43.94	11,084
2003	889,750.96	167,763	127,089	762,662	44.63	17,089
2004	1,112,228.84	195,752	148,292	963,937	45.32	21,270
2005	890,246.48	145,511	110,232	780,014	46.01	16,953
2006	1,586,415.07	239,120	181,146	1,405,269	46.71	30,085
2007	1,516,125.08	209,225	158,499	1,357,626	47.41	28,636
2008	3,057,977.43	382,522	289,780	2,768,197	48.12	57,527
2009	2,152,804.08	241,502	182,950	1,969,854	48.83	40,341
2010	1,803,435.81	179,027	135,622	1,667,814	49.54	33,666
2011	2,112,546.48	182,440	138,207	1,974,339	50.25	39,290
2012	7,235,351.36	530,134	401,603	6,833,748	50.97	134,074
2013	2,152,013.37	129,121	97,816	2,054,197	51.70	39,733

ROCKLAND ELECTRIC COMPANY

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 55-R1						
2014	1,912,208.13	89,702	67,954	1,844,254	52.42	35,182
2015	2,265,613.17	76,215	57,736	2,207,877	53.15	41,540
2016	2,372,486.29	47,877	36,269	2,336,217	53.89	43,352
2017	2,282,074.63	15,358	11,635	2,270,440	54.63	41,560
	50,499,119.96	9,698,385	7,347,015	43,152,105		990,190

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 43.6   1.96

ROCKLAND ELECTRIC COMPANY

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R1.5						
1908	124.15	112	100	24	6.13	4
1909	44.27	40	36	8	6.37	1
1910	31.41	28	25	6	6.60	1
1911	44.86	40	36	9	6.85	1
1912	537.84	479	426	112	7.09	16
1913	116.66	103	92	25	7.34	3
1914	99.59	88	78	22	7.60	3
1915	92.01	81	72	20	7.86	3
1916	164.39	144	128	36	8.13	4
1917	22.76	20	18	5	8.40	1
1918	581.62	504	449	133	8.67	15
1919	42.75	37	33	10	8.94	1
1920	90.84	78	69	22	9.23	2
1921	366.65	313	279	88	9.51	9
1922	416.16	353	314	102	9.79	10
1923	118.62	100	89	30	10.08	3
1924	599.52	504	449	151	10.38	15
1925	5,867.58	4,904	4,366	1,502	10.67	141
1926	2,788.66	2,318	2,064	725	10.97	66
1927	4,456.91	3,683	3,279	1,178	11.28	104
1928	3,297.57	2,710	2,413	885	11.58	76
1929	5,679.83	4,641	4,132	1,548	11.89	130
1930	5,285.04	4,292	3,821	1,464	12.21	120
1931	3,597.14	2,904	2,586	1,011	12.53	81
1932	5,157.37	4,138	3,684	1,473	12.85	115
1933	3,494.33	2,786	2,480	1,014	13.18	77
1934	3,738.02	2,961	2,636	1,102	13.51	82
1935	1,919.86	1,511	1,345	575	13.85	42
1936	4,942.03	3,862	3,438	1,504	14.20	106
1937	4,671.60	3,626	3,228	1,444	14.55	99
1938	4,549.46	3,506	3,121	1,428	14.91	96
1939	5,827.80	4,459	3,970	1,858	15.27	122
1940	5,434.72	4,127	3,674	1,761	15.64	113
1941	5,147.69	3,879	3,454	1,694	16.02	106
1942	5,797.96	4,335	3,860	1,938	16.40	118
1943	43.61	32	28	16	16.79	1
1944	307.12	226	201	106	17.19	6
1945	1,275.65	930	828	448	17.60	25
1946	5,743.82	4,152	3,697	2,047	18.01	114
1947	11,049.17	7,916	7,048	4,001	18.43	217
1948	10,376.01	7,365	6,557	3,819	18.86	202
1949	17,664.70	12,420	11,058	6,607	19.30	342
1950	24,260.88	16,889	15,037	9,224	19.75	467
1951	35,510.67	24,475	21,791	13,720	20.20	679

ROCKLAND ELECTRIC COMPANY

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R1.5						
1952	17,312.35	11,810	10,515	6,797	20.66	329
1953	134,386.81	90,700	80,753	53,634	21.13	2,538
1954	64,867.09	43,301	38,552	26,315	21.61	1,218
1955	68,108.47	44,962	40,031	28,077	22.09	1,271
1956	129,656.69	84,596	75,318	54,339	22.59	2,405
1957	136,016.64	87,699	78,081	57,936	23.09	2,509
1958	148,454.26	94,553	84,183	64,271	23.60	2,723
1959	94,274.00	59,291	52,789	41,485	24.12	1,720
1960	119,929.09	74,466	66,299	53,630	24.64	2,177
1961	110,024.28	67,403	60,011	50,013	25.18	1,986
1962	170,659.31	103,131	91,821	78,838	25.72	3,065
1963	138,584.88	82,576	73,520	65,065	26.27	2,477
1964	155,872.16	91,533	81,495	74,377	26.83	2,772
1965	184,588.59	106,807	95,094	89,495	27.39	3,267
1966	259,303.36	147,764	131,559	127,744	27.96	4,569
1967	163,694.93	91,820	81,750	81,945	28.54	2,871
1968	306,830.12	169,324	150,754	156,076	29.13	5,358
1969	246,469.68	133,776	119,105	127,365	29.72	4,285
1970	686,941.26	366,511	326,316	360,625	30.32	11,894
1971	433,755.75	227,353	202,419	231,337	30.93	7,479
1972	892,570.65	459,335	408,960	483,611	31.55	15,328
1973	1,085,849.58	548,441	488,294	597,556	32.17	18,575
1974	848,645.58	420,402	374,297	474,349	32.80	14,462
1975	491,319.26	238,629	212,459	278,860	33.43	8,342
1976	339,753.13	161,617	143,893	195,860	34.08	5,747
1977	313,397.43	145,996	129,985	183,412	34.72	5,283
1978	393,893.84	179,493	159,808	234,086	35.38	6,616
1979	185,418.21	82,611	73,551	111,867	36.04	3,104
1980	421,987.76	183,662	163,520	258,468	36.71	7,041
1981	630,873.56	268,071	238,672	392,202	37.38	10,492
1982	311,708.49	129,191	115,023	196,685	38.06	5,168
1983	424,556.18	171,521	152,710	271,846	38.74	7,017
1984	216,103.87	85,011	75,688	140,416	39.43	3,561
1985	468,499.83	179,257	159,598	308,902	40.13	7,698
1986	308,029.19	114,541	101,979	206,050	40.83	5,047
1987	371,164.67	134,020	119,322	251,843	41.53	6,064
1988	680,385.38	238,237	212,110	468,275	42.24	11,086
1989	747,471.08	253,452	225,656	521,815	42.96	12,147
1990	786,622.46	258,012	229,716	556,906	43.68	12,750
1991	694,509.10	220,104	195,965	498,544	44.40	11,228
1992	633,107.21	193,535	172,310	460,797	45.13	10,210
1993	937,148.54	275,953	245,689	691,460	45.86	15,078
1994	448,035.13	126,830	112,921	335,114	46.60	7,191
1995	1,084,254.33	294,581	262,275	821,979	47.34	17,363

ROCKLAND ELECTRIC COMPANY

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R1.5						
1996	1,345,269.19	350,187	311,782	1,033,487	48.08	21,495
1997	509,976.63	126,867	112,954	397,023	48.83	8,131
1998	378,734.37	89,790	79,943	298,791	49.59	6,025
1999	601,929.78	135,759	120,870	481,060	50.34	9,556
2000	695,583.56	148,751	132,438	563,146	51.10	11,020
2001	635,284.20	128,327	114,253	521,031	51.87	10,045
2002	593,352.99	112,826	100,452	492,901	52.64	9,364
2003	948,874.53	169,194	150,639	798,236	53.41	14,945
2004	1,587,452.57	264,247	235,267	1,352,186	54.18	24,957
2005	765,838.29	118,291	105,318	660,520	54.96	12,018
2006	1,516,531.52	216,045	192,352	1,324,180	55.74	23,756
2007	1,492,455.32	194,482	173,153	1,319,302	56.53	23,338
2008	4,696,176.57	554,853	494,003	4,202,174	57.32	73,311
2009	2,132,707.37	226,067	201,274	1,931,433	58.11	33,238
2010	1,870,898.35	175,284	156,061	1,714,837	58.91	29,109
2011	2,809,048.51	228,600	203,530	2,605,519	59.71	43,636
2012	2,506,400.27	173,142	154,154	2,352,246	60.51	38,874
2013	3,318,255.53	187,880	167,275	3,150,981	61.32	51,386
2014	2,065,385.99	91,187	81,186	1,984,200	62.13	31,936
2015	1,634,112.25	51,540	45,888	1,588,224	62.95	25,230
2016	2,637,671.83	49,905	44,432	2,593,240	63.77	40,666
2017	4,905,068.63	30,951	27,557	4,877,512	64.59	75,515
	57,323,421.73	11,508,124	10,246,036	47,077,386		915,001

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 51.5 1.60

ROCKLAND ELECTRIC COMPANY

ACCOUNT 365.10 OVERHEAD CONDUCTORS AND DEVICES - CAPACITORS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 30-R1						
1986	181,650.90	119,285	115,311	66,340	10.30	6,441
1988	79,163.99	49,451	47,803	31,361	11.26	2,785
1989	20,445.90	12,431	12,017	8,429	11.76	717
1990	75,723.36	44,753	43,262	32,461	12.27	2,646
1991	77,273.87	44,330	42,853	34,421	12.79	2,691
1992	14,422.82	8,019	7,752	6,671	13.32	501
1993	5,106.88	2,748	2,656	2,451	13.86	177
1994	8,711.37	4,524	4,373	4,338	14.42	301
1996	10,134.17	4,875	4,713	5,421	15.57	348
1997	957.15	442	427	530	16.16	33
1998	4,168.93	1,840	1,779	2,390	16.76	143
1999	1,167.38	491	475	692	17.37	40
2000	968.70	388	375	594	17.99	33
2001	4,665.84	1,770	1,711	2,955	18.62	159
2002	20,306.90	7,270	7,028	13,279	19.26	689
2003	10,459.96	3,518	3,401	7,059	19.91	355
2004	15,878.17	4,996	4,830	11,048	20.56	537
2005	7,367.60	2,156	2,084	5,284	21.22	249
2006	28,552.35	7,719	7,462	21,090	21.89	963
2007	32,260.86	7,990	7,724	24,537	22.57	1,087
2008	101,716.35	22,886	22,123	79,593	23.25	3,423
2009	52,613.16	10,645	10,290	42,323	23.93	1,769
2010	116,529.62	20,897	20,201	96,329	24.62	3,913
2011	63,394.90	9,890	9,560	53,835	25.32	2,126
2012	169,926.18	22,544	21,793	148,133	26.02	5,693
2013	307,349.02	33,501	32,384	274,965	26.73	10,287
2014	53,111.96	4,532	4,381	48,731	27.44	1,776
2015	74,169.71	4,549	4,397	69,773	28.16	2,478
2016	41,236.42	1,526	1,475	39,761	28.89	1,376
2017	87,413.96	1,078	1,043	86,371	29.63	2,915
	1,666,848.38	461,044	445,683	1,221,166		56,651

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 21.6   3.40

ROCKLAND ELECTRIC COMPANY

ACCOUNT 366.00 UNDERGROUND CONDUIT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R3						
1955	13,695.71	9,682	9,687	4,009	21.98	182
1958	13.39	9	9	4	23.89	
1963	1,987.73	1,265	1,266	722	27.28	26
1965	877.81	542	542	336	28.70	12
1972	316,131.00	173,154	173,247	142,884	33.92	4,212
1973	217,703.93	116,979	117,042	100,662	34.70	2,901
1974	177,044.68	93,267	93,317	83,728	35.49	2,359
1975	6,754.19	3,487	3,489	3,265	36.28	90
1976	1,820,022.47	920,203	920,695	899,327	37.08	24,254
1977	103,364.65	51,158	51,185	52,180	37.88	1,378
1978	71,690.18	34,698	34,717	36,973	38.70	955
1979	126,035.60	59,624	59,656	66,380	39.52	1,680
1980	32,890.81	15,200	15,208	17,683	40.34	438
1981	304,769.11	137,430	137,503	167,266	41.18	4,062
1982	101,380.50	44,580	44,604	56,776	42.02	1,351
1983	113,803.21	48,768	48,794	65,009	42.86	1,517
1984	133,292.00	55,592	55,622	77,670	43.72	1,777
1985	135,356.14	54,918	54,947	80,409	44.57	1,804
1986	268,367.20	105,772	105,829	162,538	45.44	3,577
1988	128,400.95	47,628	47,653	80,748	47.18	1,711
1989	381,046.62	136,822	136,895	244,152	48.07	5,079
1990	306,473.64	106,447	106,504	199,970	48.95	4,085
1991	2,875,054.20	964,092	964,607	1,910,447	49.85	38,324
1992	131,427.28	42,513	42,536	88,891	50.74	1,752
1993	353,588.44	110,083	110,142	243,446	51.65	4,713
1994	202,717.68	60,653	60,685	142,033	52.56	2,702
1995	68,030.11	19,529	19,539	48,491	53.47	907
1996	156,229.30	42,932	42,955	113,274	54.39	2,083
1997	78,959.11	20,729	20,740	58,219	55.31	1,053
1998	144,190.45	36,066	36,085	108,105	56.24	1,922
1999	253,874.08	60,353	60,385	193,489	57.17	3,384
2000	158,272.11	35,643	35,662	122,610	58.11	2,110
2001	58,453.02	12,431	12,438	46,015	59.05	779
2002	100,915.96	20,196	20,207	80,709	59.99	1,345
2003	2,064,242.52	386,984	387,191	1,677,052	60.94	27,520
2004	432,668.59	75,630	75,670	356,999	61.89	5,768
2005	135,366.82	21,947	21,959	113,408	62.84	1,805
2006	132,752.50	19,824	19,835	112,918	63.80	1,770
2007	406,188.65	55,457	55,487	350,702	64.76	5,415
2008	696,531.96	86,091	86,137	610,395	65.73	9,286
2009	314,607.83	34,859	34,878	279,730	66.69	4,194
2010	425,139.93	41,608	41,630	383,510	67.66	5,668
2011	45,835.02	3,893	3,895	41,940	68.63	611
2012	379,799.39	27,296	27,311	352,488	69.61	5,064

ROCKLAND ELECTRIC COMPANY

ACCOUNT 366.00 UNDERGROUND CONDUIT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 75-R3						
2013	88,946.84	5,242	5,245	83,702	70.58	1,186
2014	81,277.57	3,728	3,730	77,548	71.56	1,084
2015	546,845.84	17,937	17,946	528,900	72.54	7,291
2016	2,065,092.41	40,744	40,766	2,024,326	73.52	27,534
2017	995,992.27	6,504	6,507	989,485	74.51	13,280
	18,154,101.40	4,470,189	4,472,579	13,681,522		242,000

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 56.5 1.33

ROCKLAND ELECTRIC COMPANY

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R4						
1944	216.24	201	177	39	4.19	9
1955	14,395.17	12,548	11,035	3,360	7.70	436
1958	5,214.58	4,431	3,897	1,318	9.02	146
1963	5,949.51	4,784	4,207	1,743	11.75	148
1965	2,876.95	2,253	1,981	896	13.01	69
1966	3,689.85	2,849	2,506	1,184	13.67	87
1968	12,332.75	9,245	8,130	4,203	15.02	280
1969	20,634.43	15,228	13,392	7,242	15.72	461
1970	23,912.98	17,369	15,275	8,638	16.42	526
1971	19,854.61	14,183	12,473	7,382	17.14	431
1972	139,816.33	98,175	86,339	53,477	17.87	2,993
1973	185,353.30	127,862	112,447	72,906	18.61	3,918
1974	251,375.52	170,224	149,702	101,674	19.37	5,249
1975	71,404.08	47,448	41,728	29,676	20.13	1,474
1976	974,063.39	634,602	558,096	415,967	20.91	19,893
1977	321,876.63	205,412	180,648	141,229	21.71	6,505
1978	211,402.15	132,090	116,166	95,236	22.51	4,231
1979	284,449.46	173,847	152,888	131,561	23.33	5,639
1980	145,500.29	86,912	76,434	69,066	24.16	2,859
1981	678,592.06	395,843	348,121	330,471	25.00	13,219
1982	580,848.04	330,601	290,745	290,103	25.85	11,223
1983	320,897.93	178,044	156,580	164,318	26.71	6,152
1984	384,621.09	207,761	182,714	201,907	27.59	7,318
1985	281,780.32	148,076	130,224	151,556	28.47	5,323
1986	1,798,476.88	918,428	807,705	990,772	29.36	33,746
1987	123,551.88	61,220	53,839	69,713	30.27	2,303
1988	410,159.94	197,012	173,261	236,899	31.18	7,598
1989	2,524,733.46	1,174,001	1,032,467	1,492,266	32.10	46,488
1990	1,505,205.25	676,590	595,022	910,183	33.03	27,556
1991	3,318,442.48	1,440,204	1,266,577	2,051,865	33.96	60,420
1992	372,425.18	155,797	137,015	235,410	34.90	6,745
1993	838,595.62	337,535	296,843	541,753	35.85	15,112
1994	1,035,603.48	400,437	352,161	683,442	36.80	18,572
1995	483,197.91	179,107	157,514	325,684	37.76	8,625
1996	519,495.74	184,250	162,037	357,459	38.72	9,232
1997	627,922.36	212,552	186,927	440,995	39.69	11,111
1998	753,817.17	242,978	213,685	540,132	40.66	13,284
1999	759,702.38	232,469	204,443	555,259	41.64	13,335
2000	1,059,025.48	306,768	269,785	789,240	42.62	18,518
2001	627,268.46	171,451	150,781	476,487	43.60	10,929
2002	746,638.38	191,886	168,753	577,885	44.58	12,963
2003	945,602.58	227,417	200,000	745,603	45.57	16,362
2004	5,877,896.26	1,316,649	1,157,918	4,719,978	46.56	101,374
2005	1,258,264.46	261,090	229,614	1,028,650	47.55	21,633

ROCKLAND ELECTRIC COMPANY

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R4						
2006	1,129,955.04	215,821	189,802	940,153	48.54	19,369
2007	1,277,376.69	222,902	196,030	1,081,347	49.53	21,832
2008	1,391,677.78	219,885	193,376	1,198,302	50.52	23,719
2009	1,524,592.92	215,471	189,494	1,335,099	51.52	25,914
2010	2,036,127.50	254,170	223,528	1,812,600	52.51	34,519
2011	1,396,083.45	151,014	132,808	1,263,275	53.51	23,608
2012	996,788.01	91,206	80,211	916,577	54.51	16,815
2013	650,273.10	48,660	42,794	607,479	55.51	10,944
2014	1,638,473.20	95,572	84,050	1,554,423	56.50	27,512
2015	1,774,016.37	73,923	65,011	1,709,005	57.50	29,722
2016	10,939,079.73	273,477	240,507	10,698,573	58.50	182,882
2017	2,984,080.42	24,857	21,861	2,962,220	59.50	49,785
	58,265,607.22	13,794,787	12,131,724	46,133,884		1,021,116

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 45.2 1.75

ROCKLAND ELECTRIC COMPANY

ACCOUNT 367.10 UNDERGROUND CONDUCTORS AND DEVICES - CABLE CURE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 60-R4						
1989	47,951.73	22,298	24,879	23,073	32.10	719
1990	140,558.49	63,181	70,493	70,065	33.03	2,121
1991	37,367.98	16,218	18,095	19,273	33.96	568
1992	122,743.55	51,347	57,289	65,455	34.90	1,876
1993	170,125.74	68,476	76,401	93,725	35.85	2,614
1994	182,119.33	70,420	78,570	103,549	36.80	2,814
1995	139,216.50	51,603	57,575	81,642	37.76	2,162
1996	176,308.97	62,532	69,769	106,540	38.72	2,752
1997	125,170.80	42,370	47,274	77,897	39.69	1,963
1998	196,032.36	63,187	70,500	125,532	40.66	3,087
1999	82,420.88	25,221	28,140	54,281	41.64	1,304
2002	72,626.84	18,665	20,825	51,802	44.58	1,162
2003	9,227.51	2,219	2,476	6,752	45.57	148
2004	59,591.90	13,349	14,894	44,698	46.56	960
2005	60,743.01	12,604	14,062	46,681	47.55	982
2006	61,887.47	11,821	13,189	48,698	48.54	1,003
2007	32,981.70	5,755	6,421	26,561	49.53	536
2008	159,633.24	25,222	28,141	131,492	50.52	2,603
2009	79,520.04	11,239	12,540	66,980	51.52	1,300
2010	82,030.54	10,240	11,425	70,606	52.51	1,345
2011	74,785.24	8,090	9,026	65,759	53.51	1,229
2012	47,076.49	4,307	4,805	42,271	54.51	775
	2,160,120.31	660,364	736,789	1,423,331		34,023

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 41.8   1.58

ROCKLAND ELECTRIC COMPANY

ACCOUNT 368.10 LINE TRANSFORMERS - OVERHEAD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-R0.5						
1907	268.00	268	268			
1913	45.17	45	45			
1915	26.76	27	27			
1916	207.25	207	207			
1917	89.51	90	90			
1918	203.74	204	204			
1919	51.12	51	51			
1920	358.10	358	358			
1921	145.67	146	146			
1922	111.15	111	111			
1923	356.45	356	356			
1924	451.41	451	451			
1925	664.33	664	664			
1926	1,243.67	1,244	1,244			
1927	434.68	435	435			
1928	671.65	668	537	135	0.26	135
1929	173.81	171	138	36	0.75	36
1930	682.77	664	534	149	1.23	121
1931	451.90	435	350	102	1.71	60
1932	134.17	128	103	31	2.18	14
1934	61.43	57	46	15	3.12	5
1935	333.06	307	247	86	3.57	24
1936	1,204.00	1,096	881	323	4.02	80
1937	1,317.20	1,187	954	363	4.46	81
1938	114.25	102	82	32	4.89	7
1939	2,001.72	1,766	1,420	582	5.31	110
1940	470.17	410	330	140	5.73	24
1941	1,124.25	971	781	343	6.14	56
1942	325.57	278	224	102	6.55	16
1943	548.03	463	372	176	6.96	25
1944	286.86	240	193	94	7.36	13
1945	613.78	508	408	206	7.76	27
1946	3,136.84	2,569	2,066	1,071	8.15	131
1947	2,880.31	2,333	1,876	1,004	8.55	117
1948	6,451.32	5,168	4,156	2,295	8.95	256
1949	5,039.48	3,993	3,211	1,828	9.34	196
1950	4,722.24	3,700	2,975	1,747	9.74	179
1951	3,986.70	3,088	2,483	1,504	10.14	148
1952	998.86	765	615	384	10.53	36
1953	5,847.56	4,427	3,560	2,288	10.93	209
1954	3,970.08	2,970	2,388	1,582	11.34	140
1955	10,018.26	7,405	5,954	4,064	11.74	346
1956	13,214.43	9,647	7,757	5,457	12.15	449
1957	29,485.56	21,256	17,092	12,394	12.56	987

ROCKLAND ELECTRIC COMPANY

ACCOUNT 368.10 LINE TRANSFORMERS - OVERHEAD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-R0.5						
1958	16,285.79	11,592	9,321	6,965	12.97	537
1959	14,240.00	10,003	8,043	6,197	13.39	463
1960	30,179.68	20,918	16,820	13,360	13.81	967
1961	36,391.00	24,883	20,009	16,382	14.23	1,151
1962	41,252.57	27,813	22,365	18,888	14.66	1,288
1963	52,410.10	34,835	28,011	24,399	15.09	1,617
1964	73,888.80	48,389	38,910	34,979	15.53	2,252
1965	99,090.55	63,924	51,402	47,689	15.97	2,986
1966	256,077.18	162,637	130,777	125,300	16.42	7,631
1967	368,437.99	230,314	185,197	183,241	16.87	10,862
1968	171,208.20	105,312	84,682	86,526	17.32	4,996
1969	402,141.19	243,251	195,600	206,541	17.78	11,616
1970	385,936.16	229,416	184,475	201,461	18.25	11,039
1971	272,439.52	159,105	127,937	144,503	18.72	7,719
1972	349,301.27	200,345	161,099	188,202	19.19	9,807
1973	493,139.06	277,583	223,206	269,933	19.67	13,723
1974	472,894.15	261,142	209,986	262,908	20.15	13,048
1975	28,253.92	15,295	12,299	15,955	20.64	773
1976	2,268.56	1,203	967	1,302	21.14	62
1977	22,485.99	11,673	9,386	13,100	21.64	605
1978	100,466.00	51,037	41,039	59,427	22.14	2,684
1979	46,761.15	23,214	18,667	28,094	22.66	1,240
1980	107,831.94	52,310	42,063	65,769	23.17	2,839
1981	62,416.72	29,558	23,768	38,649	23.69	1,631
1982	49,495.86	22,856	18,379	31,117	24.22	1,285
1983	88,361.12	39,763	31,974	56,387	24.75	2,278
1984	78,218.54	34,277	27,562	50,657	25.28	2,004
1985	123,585.74	52,675	42,356	81,230	25.82	3,146
1986	153,206.83	63,428	51,003	102,204	26.37	3,876
1987	166,935.04	67,071	53,932	113,003	26.92	4,198
1988	184,389.31	71,831	57,760	126,629	27.47	4,610
1989	151,996.07	57,319	46,091	105,905	28.03	3,778
1990	260,212.49	94,892	76,303	183,909	28.59	6,433
1991	245,681.72	86,480	69,539	176,143	29.16	6,041
1992	244,725.49	83,043	66,775	177,950	29.73	5,986
1993	118,848.35	38,824	31,219	87,629	30.30	2,892
1994	269,152.05	84,514	67,958	201,194	30.87	6,517
1995	261,933.15	78,871	63,421	198,512	31.45	6,312
1996	135,781.99	39,105	31,445	104,337	32.04	3,256
1997	137,870.16	37,929	30,499	107,371	32.62	3,292
1998	116,112.13	30,421	24,462	91,650	33.21	2,760
1999	147,425.39	36,693	29,505	117,920	33.80	3,489
2000	220,402.56	51,967	41,787	178,616	34.39	5,194
2001	91,523.55	20,380	16,388	75,136	34.98	2,148

ROCKLAND ELECTRIC COMPANY

ACCOUNT 368.10 LINE TRANSFORMERS - OVERHEAD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-R0.5						
2002	355,548.92	74,427	59,847	295,702	35.58	8,311
2003	199,719.96	39,189	31,512	168,208	36.17	4,650
2004	312,941.93	57,234	46,022	266,920	36.77	7,259
2005	287,681.58	48,779	39,224	248,458	37.37	6,649
2006	632,177.17	98,759	79,413	552,764	37.97	14,558
2007	510,782.82	72,986	58,688	452,095	38.57	11,721
2008	637,790.88	82,485	66,327	571,464	39.18	14,586
2009	491,918.21	57,063	45,885	446,033	39.78	11,212
2010	681,425.64	69,805	56,131	625,295	40.39	15,481
2011	496,906.19	44,170	35,517	461,389	41.00	11,253
2012	703,253.27	52,976	42,598	660,655	41.61	15,877
2013	492,732.72	30,441	24,478	468,255	42.22	11,091
2014	884,761.72	42,469	34,149	850,613	42.84	19,856
2015	429,511.10	14,792	11,894	417,617	43.45	9,611
2016	500,035.03	10,336	8,312	491,723	44.07	11,158
2017	367,375.35	2,531	2,035	365,340	44.69	8,175
	15,241,140.79	4,267,962	3,432,809	11,808,332		376,507

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 31.4   2.47

ROCKLAND ELECTRIC COMPANY

ACCOUNT 368.20 LINE TRANSFORMERS - OVERHEAD INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-R0.5						
1925	51.27	51	51			
1926	50.73	51	51			
1927	17.12	17	17			
1930	393.25	383	316	77	1.23	63
1931	49.98	48	40	10	1.71	6
1932	50.38	48	40	10	2.18	5
1933	40.25	38	31	9	2.65	3
1934	6.68	6	5	2	3.12	1
1935	49.37	45	37	12	3.57	3
1936	82.24	75	62	20	4.02	5
1937	135.45	122	101	34	4.46	8
1938	107.94	96	79	29	4.89	6
1939	264.96	234	193	72	5.31	14
1940	142.42	124	102	40	5.73	7
1941	77.81	67	55	23	6.14	4
1942	242.19	207	171	71	6.55	11
1943	144.04	122	101	43	6.96	6
1944	51.68	43	35	17	7.36	2
1945	48.18	40	33	15	7.76	2
1946	133.84	110	91	43	8.15	5
1947	176.17	143	118	58	8.55	7
1948	322.08	258	213	109	8.95	12
1949	321.24	255	210	111	9.34	12
1950	232.40	182	150	82	9.74	8
1951	515.07	399	329	186	10.14	18
1952	124.80	96	79	46	10.53	4
1953	350.29	265	219	131	10.93	12
1954	1,228.47	919	758	470	11.34	41
1955	2,486.80	1,838	1,517	970	11.74	83
1956	2,474.22	1,806	1,491	983	12.15	81
1957	2,910.78	2,098	1,732	1,179	12.56	94
1958	2,177.36	1,550	1,279	898	12.97	69
1959	2,046.00	1,437	1,186	860	13.39	64
1960	2,730.00	1,892	1,562	1,168	13.81	85
1961	4,453.00	3,045	2,513	1,940	14.23	136
1962	5,475.00	3,691	3,046	2,429	14.66	166
1963	6,825.00	4,536	3,744	3,081	15.09	204
1964	14,630.00	9,581	7,907	6,723	15.53	433
1965	17,984.59	11,602	9,575	8,410	15.97	527
1966	42,425.00	26,945	22,238	20,187	16.42	1,229
1967	19,480.00	12,177	10,050	9,430	16.87	559
1968	48,925.00	30,094	24,837	24,088	17.32	1,391
1969	41,325.00	24,997	20,631	20,694	17.78	1,164
1970	124,869.00	74,227	61,262	63,607	18.25	3,485

ROCKLAND ELECTRIC COMPANY

ACCOUNT 368.20 LINE TRANSFORMERS - OVERHEAD INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-R0.5						
1971	82,934.00	48,433	39,973	42,961	18.72	2,295
1972	160,784.00	92,219	76,111	84,673	19.19	4,412
1973	152,591.00	85,892	70,889	81,702	19.67	4,154
1974	73,705.00	40,701	33,592	40,113	20.15	1,991
1975	53,730.00	29,086	24,005	29,725	20.64	1,440
1976	61,926.00	32,834	27,099	34,827	21.14	1,647
1977	73,230.00	38,014	31,374	41,856	21.64	1,934
1978	51,280.00	26,050	21,500	29,780	22.14	1,345
1979	51,969.00	25,799	21,293	30,676	22.66	1,354
1980	66,540.00	32,279	26,641	39,899	23.17	1,722
1981	56,149.00	26,590	21,945	34,204	23.69	1,444
1982	48,660.00	22,470	18,545	30,115	24.22	1,243
1983	32,687.23	14,709	12,140	20,547	24.75	830
1984	42,885.00	18,793	15,510	27,375	25.28	1,083
1985	55,946.19	23,845	19,680	36,266	25.82	1,405
1986	56,823.03	23,525	19,416	37,407	26.37	1,419
1987	70,547.38	28,345	23,394	47,153	26.92	1,752
1988	74,474.14	29,012	23,944	50,530	27.47	1,839
1989	51,315.18	19,351	15,971	35,344	28.03	1,261
1990	78,493.63	28,624	23,624	54,870	28.59	1,919
1991	99,719.17	35,101	28,970	70,749	29.16	2,426
1992	105,218.46	35,704	29,468	75,750	29.73	2,548
1993	96,749.56	31,605	26,084	70,666	30.30	2,332
1994	77,043.38	24,192	19,966	57,077	30.87	1,849
1995	123,867.88	37,298	30,783	93,085	31.45	2,960
1996	34,316.54	9,883	8,157	26,160	32.04	816
1997	16,196.66	4,456	3,678	12,519	32.62	384
1998	48,318.63	12,659	10,448	37,871	33.21	1,140
1999	23,728.72	5,906	4,874	18,855	33.80	558
2000	50,104.02	11,814	9,750	40,354	34.39	1,173
2001	68,090.01	15,162	12,514	55,576	34.98	1,589
2002	212,178.14	44,415	36,657	175,521	35.58	4,933
2003	231,827.60	45,489	37,543	194,285	36.17	5,371
2004	310,327.46	56,756	46,842	263,485	36.77	7,166
2005	336,273.12	57,018	47,059	289,214	37.37	7,739
2006	402,468.86	62,874	51,892	350,577	37.97	9,233
2007	294,182.45	42,036	34,693	259,489	38.57	6,728
2008	772,149.04	99,862	82,419	689,730	39.18	17,604
2009	548,984.32	63,682	52,559	496,425	39.78	12,479
2010	320,378.62	32,820	27,087	293,292	40.39	7,262
2011	259,984.09	23,110	19,073	240,911	41.00	5,876
2012	175,943.92	13,254	10,939	165,005	41.61	3,966
2013	717,839.49	44,348	36,602	681,237	42.22	16,135
2014	412,324.04	19,792	16,335	395,989	42.84	9,243

ROCKLAND ELECTRIC COMPANY

ACCOUNT 368.20 LINE TRANSFORMERS - OVERHEAD INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-R0.5						
2015	77,954.70	2,685	2,216	75,739	43.45	1,743
2016	489,250.33	10,113	8,346	480,904	44.07	10,912
2017	451,714.63	3,112	2,569	449,146	44.69	10,050
	8,500,430.67	1,747,677	1,442,426	7,058,005		200,739

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 35.2 2.36

ROCKLAND ELECTRIC COMPANY

ACCOUNT 368.30 LINE TRANSFORMERS - UNDERGROUND

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-R0.5						
1967	2,156.74	1,348	1,104	1,053	16.87	62
1968	2,162.94	1,330	1,089	1,074	17.32	62
1969	14,721.24	8,905	7,293	7,428	17.78	418
1970	15,111.43	8,983	7,357	7,754	18.25	425
1971	48,822.60	28,512	23,352	25,471	18.72	1,361
1972	64,245.65	36,849	30,180	34,066	19.19	1,775
1973	295,987.45	166,608	136,454	159,533	19.67	8,110
1974	153,255.43	84,631	69,314	83,941	20.15	4,166
1975	24,477.30	13,250	10,852	13,625	20.64	660
1976	17,928.62	9,506	7,786	10,143	21.14	480
1977	18,381.04	9,542	7,815	10,566	21.64	488
1978	14,634.82	7,434	6,089	8,546	22.14	386
1979	99,762.71	49,526	40,562	59,201	22.66	2,613
1980	187,938.43	91,171	74,670	113,268	23.17	4,889
1981	208,287.77	98,637	80,785	127,503	23.69	5,382
1982	136,304.38	62,943	51,551	84,753	24.22	3,499
1983	167,790.11	75,506	61,840	105,950	24.75	4,281
1984	204,829.16	89,760	73,514	131,315	25.28	5,194
1985	328,645.88	140,075	114,723	213,923	25.82	8,285
1986	314,840.01	130,344	106,753	208,087	26.37	7,891
1987	412,986.33	165,930	135,899	277,087	26.92	10,293
1988	389,303.52	151,657	124,209	265,095	27.47	9,650
1989	198,003.67	74,669	61,155	136,849	28.03	4,882
1990	78,524.02	28,635	23,452	55,072	28.59	1,926
1991	168,542.68	59,327	48,590	119,953	29.16	4,114
1992	173,702.29	58,942	48,274	125,428	29.73	4,219
1993	149,981.27	48,994	40,127	109,854	30.30	3,626
1994	244,770.13	76,858	62,948	181,822	30.87	5,890
1995	277,373.68	83,520	68,404	208,970	31.45	6,645
1996	215,609.52	62,096	50,857	164,753	32.04	5,142
1997	270,345.39	74,375	60,914	209,431	32.62	6,420
1998	264,453.13	69,287	56,747	207,706	33.21	6,254
1999	239,433.30	59,593	48,807	190,626	33.80	5,640
2000	311,396.09	73,421	60,133	251,263	34.39	7,306
2001	261,741.77	58,282	47,734	214,008	34.98	6,118
2002	363,151.67	76,019	62,260	300,892	35.58	8,457
2003	120,881.40	23,719	19,426	101,455	36.17	2,805
2004	147,164.62	26,915	22,044	125,121	36.77	3,403
2005	202,922.91	34,408	28,180	174,743	37.37	4,676
2006	406,098.69	63,441	51,959	354,140	37.97	9,327
2007	350,084.10	50,024	40,970	309,114	38.57	8,014
2008	735,111.89	95,072	77,865	657,247	39.18	16,775
2009	753,038.20	87,352	71,542	681,496	39.78	17,132
2010	360,842.66	36,965	30,275	330,568	40.39	8,184

ROCKLAND ELECTRIC COMPANY

ACCOUNT 368.30 LINE TRANSFORMERS - UNDERGROUND

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-R0.5						
2011	287,525.09	25,558	20,932	266,593	41.00	6,502
2012	245,923.27	18,525	15,172	230,751	41.61	5,546
2013	111,018.75	6,859	5,618	105,401	42.22	2,496
2014	263,244.87	12,636	10,349	252,896	42.84	5,903
2015	249,826.19	8,604	7,047	242,779	43.45	5,588
2016	218,001.79	4,506	3,690	214,312	44.07	4,863
2017	51,977.54	358	293	51,684	44.69	1,157
	10,843,264.14	2,831,407	2,318,955	8,524,309		259,380

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 32.9 2.39

ROCKLAND ELECTRIC COMPANY

ACCOUNT 368.40 LINE TRANSFORMERS - UNDERGROUND INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-R0.5						
1969	1,580.00	956	822	758	17.78	43
1971	7,230.00	4,222	3,629	3,601	18.72	192
1972	6,870.00	3,940	3,387	3,483	19.19	182
1973	13,555.00	7,630	6,558	6,997	19.67	356
1974	9,379.00	5,179	4,451	4,928	20.15	245
1975	5,048.12	2,733	2,349	2,699	20.64	131
1976	10,451.00	5,541	4,763	5,688	21.14	269
1977	11,090.00	5,757	4,948	6,142	21.64	284
1978	17,190.00	8,733	7,506	9,684	22.14	437
1979	19,104.00	9,484	8,152	10,952	22.66	483
1980	23,999.00	11,642	10,007	13,992	23.17	604
1981	40,445.00	19,153	16,462	23,983	23.69	1,012
1982	23,739.00	10,962	9,422	14,317	24.22	591
1983	28,770.00	12,946	11,127	17,643	24.75	713
1984	30,056.36	13,171	11,321	18,735	25.28	741
1985	36,405.23	15,517	13,337	23,068	25.82	893
1986	39,839.42	16,494	14,177	25,662	26.37	973
1987	53,330.87	21,427	18,417	34,914	26.92	1,297
1988	70,160.81	27,332	23,493	46,668	27.47	1,699
1989	9,132.45	3,444	2,960	6,172	28.03	220
1990	11,519.19	4,201	3,611	7,908	28.59	277
1991	19,108.23	6,726	5,781	13,327	29.16	457
1992	53,248.41	18,069	15,531	37,717	29.73	1,269
1993	47,922.51	15,655	13,456	34,467	30.30	1,138
1994	32,730.31	10,277	8,833	23,897	30.87	774
1995	22,753.47	6,851	5,889	16,864	31.45	536
1996	26,659.12	7,678	6,599	20,060	32.04	626
1997	39,697.38	10,921	9,387	30,310	32.62	929
1998	23,112.91	6,056	5,205	17,908	33.21	539
1999	9,885.74	2,460	2,114	7,772	33.80	230
2000	41,815.23	9,859	8,474	33,341	34.39	969
2001	47,826.65	10,650	9,154	38,673	34.98	1,106
2002	35,294.87	7,388	6,350	28,945	35.58	814
2003	43,182.66	8,473	7,283	35,900	36.17	993
2004	37,084.01	6,782	5,829	31,255	36.77	850
2005	31,009.30	5,258	4,519	26,490	37.37	709
2006	38,296.50	5,983	5,143	33,154	37.97	873
2007	74,584.66	10,657	9,160	65,425	38.57	1,696
2008	103,651.02	13,405	11,522	92,129	39.18	2,351
2009	85,545.64	9,923	8,529	77,017	39.78	1,936
2010	21,172.84	2,169	1,864	19,309	40.39	478
2011	136,455.10	12,129	10,425	126,030	41.00	3,074
2012	78,250.22	5,895	5,067	73,183	41.61	1,759
2013	424,142.24	26,204	22,523	401,619	42.22	9,513

ROCKLAND ELECTRIC COMPANY

ACCOUNT 368.40 LINE TRANSFORMERS - UNDERGROUND INSTALLATIONS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-R0.5						
2014	155,837.48	7,480	6,429	149,408	42.84	3,488
2015	100,553.67	3,463	2,977	97,577	43.45	2,246
2016	570,921.01	11,801	10,144	560,777	44.07	12,725
2017	340,164.77	2,344	2,014	338,150	44.69	7,567
	3,109,800.40	455,020	391,100	2,718,700		71,287

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 38.1   2.29

ROCKLAND ELECTRIC COMPANY

ACCOUNT 369.10 SERVICES - OVERHEAD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R3						
1937	157.09	139	136	21	7.43	3
1938	72.49	64	63	9	7.71	1
1939	82.47	72	71	11	8.01	1
1940	459.07	400	392	67	8.31	8
1941	586.03	508	498	88	8.63	10
1942	459.40	396	388	71	8.95	8
1943	12.92	11	11	2	9.29	
1944	74.28	63	62	12	9.63	1
1945	363.30	307	301	62	9.99	6
1946	760.12	639	626	134	10.36	13
1947	1,324.47	1,105	1,083	241	10.75	22
1948	1,848.38	1,531	1,500	348	11.15	31
1949	2,632.53	2,164	2,120	513	11.56	44
1950	3,816.66	3,113	3,050	767	11.99	64
1951	6,530.70	5,282	5,175	1,356	12.43	109
1952	4,426.57	3,549	3,477	950	12.88	74
1953	25,217.43	20,038	19,631	5,586	13.35	418
1954	19,312.74	15,201	14,892	4,421	13.84	319
1955	18,851.72	14,696	14,398	4,454	14.33	311
1956	34,305.65	26,468	25,931	8,375	14.85	564
1957	46,467.72	35,473	34,753	11,715	15.38	762
1958	46,298.16	34,959	34,249	12,049	15.92	757
1959	49,984.69	37,312	36,555	13,430	16.48	815
1960	67,449.72	49,757	48,747	18,703	17.05	1,097
1961	63,499.60	46,277	45,338	18,162	17.63	1,030
1962	61,558.36	44,294	43,395	18,163	18.23	996
1963	59,023.82	41,916	41,065	17,959	18.84	953
1964	62,930.11	44,090	43,195	19,735	19.46	1,014
1965	67,278.00	46,474	45,531	21,747	20.10	1,082
1966	66,795.96	45,473	44,550	22,246	20.75	1,072
1967	65,738.86	44,086	43,191	22,548	21.41	1,053
1968	73,156.49	48,306	47,325	25,831	22.08	1,170
1969	71,603.07	46,531	45,586	26,017	22.76	1,143
1970	114,495.62	73,189	71,703	42,793	23.45	1,825
1971	98,252.63	61,733	60,480	37,773	24.16	1,563
1972	127,265.38	78,571	76,976	50,289	24.87	2,022
1973	136,441.01	82,726	81,047	55,394	25.59	2,165
1974	99,447.05	59,163	57,962	41,485	26.33	1,576
1975	92,634.66	54,056	52,959	39,676	27.07	1,466
1976	96,999.70	55,484	54,358	42,642	27.82	1,533
1977	104,933.07	58,795	57,601	47,332	28.58	1,656
1978	106,226.85	58,261	57,078	49,149	29.35	1,675
1979	90,682.89	48,648	47,660	43,023	30.13	1,428
1980	96,532.42	50,627	49,599	46,933	30.91	1,518

ROCKLAND ELECTRIC COMPANY

ACCOUNT 369.10 SERVICES - OVERHEAD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R3						
1981	77,236.78	39,557	38,754	38,483	31.71	1,214
1982	87,695.39	43,835	42,945	44,750	32.51	1,376
1983	89,898.95	43,815	42,926	46,973	33.32	1,410
1984	114,292.74	54,263	53,162	61,131	34.14	1,791
1985	126,066.43	58,262	57,079	68,987	34.96	1,973
1986	142,793.95	64,147	62,845	79,949	35.80	2,233
1987	186,310.13	81,289	79,639	106,671	36.64	2,911
1988	176,725.13	74,795	73,277	103,448	37.49	2,759
1989	214,124.81	87,823	86,040	128,085	38.34	3,341
1990	181,031.72	71,828	70,370	110,662	39.21	2,822
1991	141,597.33	54,286	53,184	88,413	40.08	2,206
1992	76,090.37	28,153	27,581	48,509	40.95	1,185
1993	76,397.49	27,233	26,680	49,717	41.83	1,189
1994	75,015.68	25,713	25,191	49,825	42.72	1,166
1995	72,920.25	23,985	23,498	49,422	43.62	1,133
1996	71,797.79	22,622	22,163	49,635	44.52	1,115
1997	73,763.89	22,209	21,758	52,006	45.43	1,145
1998	66,128.43	18,984	18,599	47,529	46.34	1,026
1999	66,743.33	18,216	17,846	48,897	47.26	1,035
2000	52,148.21	13,494	13,220	38,928	48.18	808
2001	57,457.45	14,046	13,761	43,696	49.11	890
2002	65,687.23	15,108	14,801	50,886	50.05	1,017
2003	66,111.06	14,250	13,961	52,150	50.99	1,023
2004	64,785.91	13,027	12,763	52,023	51.93	1,002
2005	75,042.23	13,992	13,708	61,334	52.88	1,160
2006	104,453.74	17,950	17,586	86,868	53.83	1,614
2007	117,282.76	18,440	18,066	99,217	54.78	1,811
2008	90,944.06	12,956	12,693	78,251	55.74	1,404
2009	64,737.99	8,257	8,089	56,649	56.71	999
2010	93,573.27	10,552	10,338	83,235	57.67	1,443
2011	75,744.60	7,412	7,261	68,484	58.64	1,168
2012	98,976.04	8,207	8,040	90,936	59.61	1,526
2013	102,990.55	6,988	6,846	96,145	60.59	1,587
2014	100,632.48	5,325	5,217	95,415	61.56	1,550
2015	136,094.55	5,151	5,047	131,048	62.54	2,095
2016	200,969.63	4,576	4,483	196,487	63.52	3,093
2017	132,984.51	1,003	983	132,002	64.51	2,046
	5,904,236.72	2,393,696	2,345,108	3,559,129		92,644

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 38.4   1.57

ROCKLAND ELECTRIC COMPANY

ACCOUNT 369.20 SERVICES - UNDERGROUND

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R3						
1937	12.42	11	12			
1939	17.28	15	17			
1941	22.51	20	22	1	8.63	
1949	21.14	17	19	2	11.56	
1950	25.91	21	23	3	11.99	
1951	53.78	43	47	7	12.43	1
1952	91.41	73	81	10	12.88	1
1953	74.50	59	65	10	13.35	1
1954	531.04	418	461	70	13.84	5
1955	1,041.51	812	896	146	14.33	10
1956	909.54	702	775	135	14.85	9
1957	2,006.06	1,531	1,690	316	15.38	21
1958	1,385.91	1,046	1,155	231	15.92	15
1959	1,714.12	1,280	1,413	301	16.48	18
1960	2,204.42	1,626	1,795	409	17.05	24
1961	1,950.55	1,422	1,570	381	17.63	22
1962	2,707.25	1,948	2,150	557	18.23	31
1963	3,296.71	2,341	2,584	713	18.84	38
1964	3,695.86	2,589	2,858	838	19.46	43
1965	3,005.45	2,076	2,292	713	20.10	35
1966	5,938.32	4,043	4,463	1,475	20.75	71
1967	5,027.15	3,371	3,721	1,306	21.41	61
1968	6,755.50	4,461	4,924	1,832	22.08	83
1969	8,171.05	5,310	5,862	2,309	22.76	101
1970	54,214.98	34,656	38,256	15,959	23.45	681
1971	13,353.26	8,390	9,262	4,091	24.16	169
1972	29,895.05	18,457	20,374	9,521	24.87	383
1973	85,276.67	51,704	57,075	28,202	25.59	1,102
1974	104,773.99	62,332	68,807	35,967	26.33	1,366
1975	86,626.78	50,550	55,801	30,826	27.07	1,139
1976	188,745.65	107,963	119,178	69,568	27.82	2,501
1977	214,397.26	120,129	132,607	81,790	28.58	2,862
1978	247,781.06	135,898	150,015	97,766	29.35	3,331
1979	255,243.09	136,928	151,151	104,092	30.13	3,455
1980	205,018.15	107,524	118,693	86,325	30.91	2,793
1981	236,476.73	121,112	133,693	102,784	31.71	3,241
1982	227,185.45	113,559	125,355	101,830	32.51	3,132
1983	350,564.42	170,858	188,606	161,958	33.32	4,861
1984	569,138.33	270,210	298,278	270,860	34.14	7,934
1985	541,940.57	250,458	276,475	265,466	34.96	7,593
1986	405,472.67	182,150	201,071	204,402	35.80	5,710
1987	285,340.42	124,497	137,429	147,911	36.64	4,037
1988	227,343.77	96,219	106,214	121,130	37.49	3,231
1989	182,349.60	74,791	82,560	99,790	38.34	2,603

ROCKLAND ELECTRIC COMPANY

ACCOUNT 369.20 SERVICES - UNDERGROUND

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 65-R3						
1990	285,956.95	113,459	125,245	160,712	39.21	4,099
1991	314,131.02	120,432	132,942	181,189	40.08	4,521
1992	360,928.78	133,544	147,416	213,513	40.95	5,214
1993	410,754.83	146,418	161,627	249,128	41.83	5,956
1994	535,857.47	183,676	202,755	333,102	42.72	7,797
1995	473,633.58	155,788	171,971	301,663	43.62	6,916
1996	483,872.42	152,459	168,296	315,576	44.52	7,088
1997	402,038.70	121,046	133,620	268,419	45.43	5,908
1998	356,519.19	102,350	112,982	243,537	46.34	5,255
1999	546,841.91	149,244	164,747	382,095	47.26	8,085
2000	457,095.18	118,283	130,570	326,525	48.18	6,777
2001	425,472.62	104,011	114,815	310,658	49.11	6,326
2002	318,500.36	73,255	80,864	237,636	50.05	4,748
2003	407,468.46	87,826	96,949	310,519	50.99	6,090
2004	340,092.73	68,386	75,489	264,604	51.93	5,095
2005	379,483.60	70,759	78,109	301,375	52.88	5,699
2006	343,616.18	59,050	65,184	278,432	53.83	5,172
2007	357,156.72	56,156	61,989	295,168	54.78	5,388
2008	305,840.01	43,570	48,096	257,744	55.74	4,624
2009	276,362.20	35,247	38,908	237,454	56.71	4,187
2010	322,058.38	36,319	40,092	281,966	57.67	4,889
2011	468,215.11	45,815	50,574	417,641	58.64	7,122
2012	303,709.00	25,184	27,800	275,909	59.61	4,629
2013	138,366.82	9,388	10,363	128,004	60.59	2,113
2014	489,974.05	25,929	28,622	461,352	61.56	7,494
2015	383,536.61	14,517	16,025	367,512	62.54	5,876
2016	374,533.91	8,528	9,414	365,120	63.52	5,748
2017	355,676.74	2,682	2,961	352,716	64.51	5,468
	15,179,490.82	4,536,941	5,008,220	10,171,271		220,998

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 46.0   1.46

ROCKLAND ELECTRIC COMPANY

ACCOUNT 370.10 METERS - ELECTROMECHANICAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-L0						
1901	1,505.70	1,506	1,506			
1922	13.20	12	13			
1927	10.92	10	11			
1948	19.38	15	17	2	5.11	
1949	91.65	72	81	11	5.26	2
1950	765.09	600	671	94	5.41	17
1951	533.27	415	464	69	5.56	12
1952	313.87	242	271	43	5.72	8
1953	770.43	590	660	110	5.87	19
1954	1,098.98	834	933	166	6.03	28
1955	1,657.67	1,247	1,394	264	6.19	43
1956	2,123.50	1,583	1,770	354	6.36	56
1957	1,587.80	1,174	1,313	275	6.52	42
1958	5,848.51	4,283	4,789	1,060	6.69	158
1959	6,309.68	4,578	5,119	1,191	6.86	174
1960	5,138.40	3,693	4,129	1,009	7.03	144
1961	10,754.39	7,657	8,562	2,192	7.20	304
1962	12,106.38	8,533	9,541	2,565	7.38	348
1963	13,784.64	9,616	10,752	3,033	7.56	401
1964	11,337.48	7,827	8,752	2,585	7.74	334
1965	5,861.63	4,002	4,475	1,387	7.93	175
1966	12,059.12	8,147	9,110	2,949	8.11	364
1967	16,305.03	10,892	12,179	4,126	8.30	497
1968	20,146.40	13,297	14,868	5,278	8.50	621
1969	12,980.30	8,468	9,469	3,511	8.69	404
1970	15,110.52	9,737	10,888	4,223	8.89	475
1971	13,635.87	8,678	9,704	3,932	9.09	433
1972	19,235.88	12,080	13,508	5,728	9.30	616
1973	21,616.16	13,402	14,986	6,630	9.50	698
1974	9,077.28	5,548	6,204	2,873	9.72	296
1975	12,980.40	7,825	8,750	4,230	9.93	426
1976	14,635.87	8,694	9,721	4,915	10.15	484
1977	17,456.18	10,215	11,422	6,034	10.37	582
1978	13,467.60	7,757	8,674	4,794	10.60	452
1979	25,574.78	14,496	16,209	9,366	10.83	865
1980	8,948.37	4,990	5,580	3,368	11.06	305
1981	22,971.33	12,588	14,076	8,895	11.30	787
1982	25,063.37	13,494	15,089	9,974	11.54	864
1983	23,855.16	12,615	14,106	9,749	11.78	828
1984	13,653.20	7,078	7,914	5,739	12.04	477
1985	26,339.92	13,391	14,974	11,366	12.29	925
1986	95,866.56	47,742	53,384	42,483	12.55	3,385
1987	130,211.52	63,491	70,995	59,217	12.81	4,623
1988	269,243.08	128,375	143,547	125,696	13.08	9,610

ROCKLAND ELECTRIC COMPANY

ACCOUNT 370.10 METERS - ELECTROMECHANICAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-L0						
1989	22.87	11	12	11	13.36	1
1990	120,086.66	54,567	61,016	59,071	13.64	4,331
1991	146,440.70	64,903	72,573	73,868	13.92	5,307
1992	48,020.40	20,726	23,175	24,845	14.21	1,748
1993	86,784.94	36,415	40,719	46,066	14.51	3,175
1994	20,526.81	8,367	9,356	11,171	14.81	754
1995	124,541.29	49,219	55,036	69,505	15.12	4,597
1996	126,522.42	48,433	54,157	72,365	15.43	4,690
1997	119,825.64	44,335	49,575	70,251	15.75	4,460
1998	154,596.33	55,160	61,679	92,917	16.08	5,778
1999	156,566.25	53,796	60,153	96,413	16.41	5,875
2000	64,986.25	21,445	23,979	41,007	16.75	2,448
2001	200,471.22	63,349	70,836	129,635	17.10	7,581
2002	173,899.32	52,518	58,725	115,174	17.45	6,600
2003	220,830.74	63,511	71,016	149,814	17.81	8,412
	2,686,188.31	1,138,244	1,272,587	1,413,601		97,039

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 14.6   3.61

ROCKLAND ELECTRIC COMPANY

ACCOUNT 370.11 METERS - SOLID STATE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-S2.5						
2004	308,488.63	187,715	118,527	189,962	7.83	24,261
2005	222,514.85	127,835	80,717	141,798	8.51	16,663
2006	281,273.11	151,184	95,460	185,813	9.25	20,088
2007	75,041.52	37,371	23,597	51,445	10.04	5,124
2008	116,137.18	53,017	33,476	82,661	10.87	7,605
2009	116,177.13	47,981	30,296	85,881	11.74	7,315
2010	110,231.32	40,565	25,613	84,618	12.64	6,694
2011	238,102.65	76,431	48,260	189,843	13.58	13,980
2012	290,746.07	79,374	50,118	240,628	14.54	16,549
2013	70,266.53	15,740	9,939	60,328	15.52	3,887
2014	66,961.65	11,685	7,378	59,584	16.51	3,609
2015	161,274.84	20,159	12,728	148,547	17.50	8,488
2016	81,682.81	6,126	3,868	77,815	18.50	4,206
2017	34,592.10	865	547	34,046	19.50	1,746
	2,173,490.39	856,048	540,524	1,632,967		140,215

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 11.6   6.45

ROCKLAND ELECTRIC COMPANY

ACCOUNT 370.20 METER INSTALLATIONS - ELECTROMECHANICAL

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 25-L0						
1978	4,100.30	2,362	2,648	1,452	10.60	137
1979	24,272.47	13,758	15,424	8,848	10.83	817
1980	17,574.04	9,799	10,985	6,589	11.06	596
1981	24,328.15	13,332	14,946	9,382	11.30	830
1982	19,722.20	10,618	11,903	7,819	11.54	678
1983	21,933.24	11,598	13,002	8,931	11.78	758
1984	418,807.79	217,110	243,394	175,414	12.04	14,569
1985	24,832.66	12,625	14,153	10,680	12.29	869
1986	23,831.57	11,868	13,305	10,527	12.55	839
1987	38,691.98	18,866	21,150	17,542	12.81	1,369
1988	34,655.61	16,524	18,524	16,132	13.08	1,233
1989	28,216.94	13,138	14,729	13,488	13.36	1,010
1990	31,923.82	14,506	16,262	15,662	13.64	1,148
1991	36,861.36	16,337	18,315	18,546	13.92	1,332
1992	28,251.51	12,193	13,669	14,583	14.21	1,026
1993	23,511.70	9,866	11,060	12,452	14.51	858
1994	19,184.23	7,819	8,766	10,418	14.81	703
1995	42,914.60	16,960	19,013	23,902	15.12	1,581
1996	36,457.35	13,956	15,646	20,811	15.43	1,349
1997	34,792.15	12,873	14,431	20,361	15.75	1,293
1998	64,611.01	23,053	25,844	38,767	16.08	2,411
1999	62,521.43	21,482	24,083	38,438	16.41	2,342
2000	48,981.36	16,164	18,121	30,860	16.75	1,842
2001	51,902.63	16,401	18,387	33,516	17.10	1,960
2002	78,319.44	23,652	26,515	51,804	17.45	2,969
2003	94,136.66	27,074	30,352	63,785	17.81	3,581
	1,335,336.20	583,934	654,627	680,709		48,100

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 14.2   3.60

ROCKLAND ELECTRIC COMPANY

ACCOUNT 370.21 METER INSTALLATIONS - SOLID STATE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 20-S2.5						
2004	121,017.55	73,639	47,751	73,267	7.83	9,357
2005	282,432.62	162,258	105,216	177,217	8.51	20,825
2006	223,584.49	120,177	77,929	145,655	9.25	15,746
2007	144,296.54	71,860	46,598	97,699	10.04	9,731
2008	212,754.44	97,122	62,979	149,775	10.87	13,779
2009	251,213.74	103,751	67,278	183,936	11.74	15,667
2010	200,869.51	73,920	47,933	152,937	12.64	12,099
2011	249,129.53	79,971	51,857	197,273	13.58	14,527
2012	113,375.61	30,952	20,071	93,305	14.54	6,417
2013	321,286.39	71,968	46,668	274,618	15.52	17,694
2014	277,619.56	48,445	31,414	246,206	16.51	14,913
2015	278,474.37	34,809	22,572	255,902	17.50	14,623
2016	207,159.38	15,537	10,075	197,084	18.50	10,653
2017	113,015.57	2,825	1,832	111,183	19.50	5,702
	2,996,229.30	987,234	640,173	2,356,056		181,733

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 13.0   6.07

ROCKLAND ELECTRIC COMPANY

ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 35-R0.5						
1986	81,751.16	42,440	53,510	28,241	16.83	1,678
1990	58,461.61	26,909	33,928	24,534	18.89	1,299
2000	24,516.66	7,383	9,309	15,208	24.46	622
2005	377,936.24	81,959	103,339	274,597	27.41	10,018
2009	40,074.74	5,954	7,507	32,568	29.80	1,093
	582,740.41	164,645	207,593	375,148		14,710

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 25.5 2.52

ROCKLAND ELECTRIC COMPANY

ACCOUNT 373.10 STREET LIGHTING AND SIGNAL SYSTEMS - OVERHEAD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-R0.5						
1937	30.05	30	30			
1942	29.88	28	22	8	2.18	4
1952	137.00	115	89	48	6.47	7
1954	973.05	796	616	357	7.27	49
1955	665.00	537	416	249	7.67	32
1958	2,226.50	1,734	1,343	884	8.85	100
1959	2,533.96	1,948	1,508	1,026	9.25	111
1960	4,670.18	3,543	2,744	1,926	9.65	200
1961	6,598.14	4,939	3,825	2,773	10.06	276
1962	8,227.34	6,076	4,705	3,522	10.46	337
1963	14,631.66	10,656	8,252	6,380	10.87	587
1964	12,918.19	9,275	7,182	5,736	11.28	509
1965	73,386.49	51,939	40,220	33,166	11.69	2,837
1966	59,916.02	41,776	32,350	27,566	12.11	2,276
1967	67,421.85	46,302	35,855	31,567	12.53	2,519
1968	32,104.01	21,702	16,805	15,299	12.96	1,180
1969	26,870.72	17,876	13,842	13,029	13.39	973
1970	91,340.97	59,760	46,276	45,065	13.83	3,258
1971	40,769.51	26,225	20,308	20,462	14.27	1,434
1972	43,194.72	27,299	21,139	22,056	14.72	1,498
1973	30,667.57	19,037	14,742	15,926	15.17	1,050
1974	28,735.45	17,507	13,557	15,178	15.63	971
1975	24,285.84	14,517	11,241	13,045	16.09	811
1976	32,588.62	19,097	14,788	17,801	16.56	1,075
1977	38,301.97	21,995	17,032	21,270	17.03	1,249
1978	45,203.98	25,416	19,681	25,523	17.51	1,458
1979	37,060.78	20,383	15,784	21,277	18.00	1,182
1980	43,789.28	23,548	18,235	25,554	18.49	1,382
1981	40,144.33	21,096	16,336	23,808	18.98	1,254
1982	42,951.87	22,024	17,055	25,897	19.49	1,329
1983	36,824.96	18,412	14,258	22,567	20.00	1,128
1984	60,325.38	29,394	22,762	37,563	20.51	1,831
1985	54,943.01	26,057	20,177	34,766	21.03	1,653
1986	74,139.64	34,178	26,466	47,674	21.56	2,211
1987	48,652.13	21,784	16,869	31,783	22.09	1,439
1988	86,663.41	37,655	29,158	57,505	22.62	2,542
1989	73,267.74	30,827	23,871	49,397	23.17	2,132
1990	86,286.33	35,140	27,211	59,075	23.71	2,492
1991	100,920.48	39,712	30,751	70,169	24.26	2,892
1992	78,678.66	29,859	23,122	55,557	24.82	2,238
1993	97,095.70	35,488	27,480	69,616	25.38	2,743
1994	77,032.47	27,058	20,953	56,079	25.95	2,161
1995	60,904.10	20,525	15,894	45,010	26.52	1,697
1996	31,328.44	10,111	7,830	23,498	27.09	867

ROCKLAND ELECTRIC COMPANY

ACCOUNT 373.10 STREET LIGHTING AND SIGNAL SYSTEMS - OVERHEAD

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-R0.5						
1997	20,302.10	6,258	4,846	15,456	27.67	559
1998	21,667.68	6,365	4,929	16,739	28.25	593
1999	12,653.27	3,533	2,736	9,917	28.83	344
2000	44,153.16	11,679	9,044	35,109	29.42	1,193
2001	32,982.25	8,237	6,378	26,604	30.01	887
2002	21,896.05	5,146	3,985	17,911	30.60	585
2003	20,561.90	4,529	3,507	17,055	31.19	547
2004	21,433.34	4,399	3,406	18,027	31.79	567
2005	25,285.78	4,811	3,725	21,561	32.39	666
2006	27,876.28	4,885	3,783	24,093	32.99	730
2007	24,304.40	3,895	3,016	21,288	33.59	634
2008	21,994.81	3,195	2,474	19,521	34.19	571
2009	42,088.65	5,482	4,245	37,844	34.79	1,088
2010	30,807.39	3,543	2,744	28,063	35.40	793
2011	74,849.30	7,485	5,796	69,053	36.00	1,918
2012	131,485.50	11,143	8,629	122,856	36.61	3,356
2013	172,124.17	11,963	9,263	162,861	37.22	4,376
2014	246,812.20	13,328	10,321	236,491	37.84	6,250
2015	229,282.22	8,885	6,880	222,402	38.45	5,784
2016	187,112.76	4,350	3,368	183,745	39.07	4,703
2017	319,568.35	2,477	1,918	317,650	39.69	8,003
	3,548,678.94	1,068,964	827,773	2,720,906		102,121

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 26.6   2.88

ROCKLAND ELECTRIC COMPANY

ACCOUNT 373.20 STREET LIGHTING AND SIGNAL SYSTEMS - UNDERGROUND

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-R0.5						
1955	14,553.36	11,763	9,467	5,086	7.67	663
1956	24,326.74	19,425	15,633	8,694	8.06	1,079
1957	5,920.19	4,668	3,757	2,163	8.46	256
1959	1,826.69	1,404	1,130	697	9.25	75
1960	1,501.24	1,139	917	584	9.65	61
1965	3,251.77	2,301	1,852	1,400	11.69	120
1968	14,350.86	9,701	7,807	6,544	12.96	505
1969	3,062.01	2,037	1,639	1,423	13.39	106
1970	4,703.76	3,077	2,476	2,228	13.83	161
1971	22,014.08	14,161	11,396	10,618	14.27	744
1972	31,115.32	19,665	15,826	15,289	14.72	1,039
1973	8,822.10	5,476	4,407	4,415	15.17	291
1974	9,615.18	5,858	4,714	4,901	15.63	314
1975	8,527.85	5,098	4,103	4,425	16.09	275
1976	4,968.00	2,911	2,343	2,625	16.56	159
1977	11,719.78	6,730	5,416	6,304	17.03	370
1978	22,042.23	12,393	9,974	12,068	17.51	689
1979	21,487.49	11,818	9,511	11,976	18.00	665
1980	3,150.15	1,694	1,363	1,787	18.49	97
1981	36,192.61	19,019	15,306	20,887	18.98	1,100
1982	41,892.35	21,480	17,286	24,606	19.49	1,262
1983	23,377.31	11,689	9,407	13,970	20.00	698
1984	27,271.78	13,288	10,694	16,578	20.51	808
1985	6,622.28	3,141	2,528	4,094	21.03	195
1986	55,128.95	25,414	20,452	34,677	21.56	1,608
1988	4,696.14	2,040	1,642	3,054	22.62	135
1989	46,808.00	19,694	15,849	30,959	23.17	1,336
1990	32,022.81	13,041	10,495	21,528	23.71	908
1991	40,674.18	16,005	12,880	27,794	24.26	1,146
1992	3,768.64	1,430	1,151	2,618	24.82	105
1993	20,965.18	7,663	6,167	14,798	25.38	583
1994	28,824.89	10,125	8,148	20,677	25.95	797
1995	28,535.47	9,616	7,739	20,796	26.52	784
1996	5,525.74	1,783	1,435	4,091	27.09	151
1997	25,295.80	7,797	6,275	19,021	27.67	687
1998	44,913.36	13,193	10,617	34,296	28.25	1,214
1999	45,876.79	12,811	10,310	35,567	28.83	1,234
2000	32,532.54	8,605	6,925	25,608	29.42	870
2001	31,080.79	7,762	6,247	24,834	30.01	828
2002	32,719.10	7,689	6,188	26,531	30.60	867
2003	18,226.29	4,014	3,230	14,996	31.19	481
2004	18,001.62	3,695	2,974	15,028	31.79	473
2005	17,766.53	3,380	2,720	15,047	32.39	465
2006	47,831.29	8,382	6,745	41,086	32.99	1,245

ROCKLAND ELECTRIC COMPANY

ACCOUNT 373.20 STREET LIGHTING AND SIGNAL SYSTEMS - UNDERGROUND

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 40-R0.5						
2007	64,736.46	10,374	8,349	56,387	33.59	1,679
2008	39,854.25	5,789	4,659	35,195	34.19	1,029
2009	24,393.22	3,177	2,557	21,836	34.79	628
2010	31,076.49	3,574	2,876	28,200	35.40	797
2011	38,345.20	3,835	3,086	35,259	36.00	979
2012	35,945.38	3,046	2,451	33,494	36.61	915
2013	87,979.86	6,115	4,921	83,059	37.22	2,232
2014	38,731.52	2,092	1,684	37,048	37.84	979
2015	39,757.88	1,541	1,240	38,518	38.45	1,002
2016	5,884.13	137	110	5,774	39.07	148
2017	56,656.20	439	353	56,303	39.69	1,419
	1,396,869.83	434,194	349,427	1,047,442		39,456

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 26.5   2.82

ROCKLAND ELECTRIC COMPANY

ACCOUNT 390.00 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF DECEMBER 31, 2017

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. IOWA 45-S0						
1974	254,794.43	149,648	147,450	107,344	18.57	5,781
1975	10,270.05	5,929	5,842	4,428	19.02	233
1978	31,012.92	16,954	16,705	14,308	20.40	701
1980	1,161.38	610	601	560	21.35	26
1981	172.78	89	88	85	21.82	4
1982	3,086.69	1,557	1,534	1,553	22.30	70
1983	256.87	127	125	132	22.79	6
1989	5,372.74	2,291	2,257	3,116	25.81	121
1990	11,479.63	4,760	4,690	6,790	26.34	258
1991	4,630.70	1,866	1,839	2,792	26.87	104
1992	180.48	71	70	110	27.40	4
1995	26,147.39	9,268	9,132	17,015	29.05	586
1997	4,884.42	1,608	1,584	3,300	30.19	109
2004	2,576.64	602	593	1,984	34.48	58
2008	5,457.97	946	932	4,526	37.20	122
2009	33,512.96	5,273	5,196	28,317	37.92	747
2010	17,837.68	2,513	2,476	15,362	38.66	397
2011	20,699.09	2,567	2,529	18,170	39.42	461
2013	92,834.39	8,252	8,131	84,703	41.00	2,066
2014	132,926.27	9,363	9,226	123,700	41.83	2,957
2016	29,965.62	946	932	29,034	43.58	666
	689,261.10	225,240	221,932	467,329		15,477

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 30.2 2.25

EXHIBIT P-8

ROCKLAND ELECTRIC COMPANY
EMBEDDED COST OF SERVICE STUDY
YEAR 2016

EXHIBIT P-8
Schedule 1

ROCKLAND ELECTRIC COMPANY
COMPANY - SPONSORED EMBEDDED
COST OF SERVICE STUDY
YEAR 2016

RATES IN EFFECT
APRIL 1, 2019

EXPLANATION OF COSTING METHODS AND TABULAR RESULTS

TABLE OF CONTENTS

ROCKLAND ELECTRIC COMPANY
COST OF SERVICE STUDY
YEAR 2016

I - SUMMARY

The cost of serving Rockland Electric Company's Delivery Service customers is based on an embedded cost analysis of Distribution Rate Base and Operating Expenses for Rockland Electric Company in the year 2016. Purchased Power, Transmission Rate Base and Transmission Operating Expenses were identified and removed from the study. The revenues reflect current rates, i.e. rates effective April 1, 2019. The results are tabulated in the attached seven tables. The costs were functionalized and classified to the Operating Functions and then allocated by function to the service classes. The results are shown on **Tables 2 through 5.** The allocation to the service classes was based on the allocation factors tabulated in **Table 7**. The allocation factors were derived from physical quantities, or other appropriate bases of apportionment applicable to each class. **Table 6** shows the Customer Costs derived from the customer related costs. **Table 1** summarizes the resulting class rates-of-return on rate base computed in **Tables 2 through 5**.The Operating Revenues tabulated on **Table 4** reflect current rates, i.e. rates effective April 1, 2019 and other operating revenues. These revenues comprise the annual sales revenues for Rockland Electric service classes (Retail Access customers are priced at full service rates).

II - DESCRIPTION OF FUNCTIONS,

ALLOCATION FACTORS, AND SERVICE CLASSES

In **Tables 2, 3 and 5,** each function has a corresponding line number and name followed by the Allocation Factor Code Name as well as a letter such as **"D"** for demand-related, **"C"** for customer – related, and **"R"** for revenue – related. In **Tables 4 and 6**, only specific allocation factors are shown. A list of all allocation factors is shown in **Table 7**. The Service Classes are shown by Column (No.), Name and SC.

Functions and Allocation Factors Used In Tables 2, 3 and 5:

Lines 1, High Tension ≥ 69 kV – D DO2

The High Tension ≥ 69 kV function includes the fixed and operating costs, together with federal income taxes, for the feeders operated at 69 kV and above, and provides the source of supply from the transmission substations to the lower voltage substations and to the primary voltage customers. In addition, the High Tension ≥ 69 kV function connects certain primary voltage customers (served under the Company's SC 7 HV TOD service classification) directly to the Company's system, whereas these customers construct their own substation facilities to reduce the service voltage to the necessary utilization voltages. D02 is the allocation factor used to allocate the High Tension ≥ 69 kV function to service classes. It is based on the class maximum non-coincident summer (or winter) peak kW based on a five (5) day, four (4) hour peak.

Lines 2, High Tension < 69 kV – D DO2A

The High Tension < 69 kV function includes the fixed and operating costs, together with federal income taxes, for the substations and feeders operated between 4.16 kV and 69 kV, and provides the source of supply from the transmission substations to the lower voltage substations and to the primary voltage customers, excluding customers served under the Company's SC 7 HV TOD service classification. D02A is the allocation factor used to allocate the High Tension < 69 kV function to service classes. It is based on the class maximum non-coincident summer (or winter) peak kW based on a five (5) day, four (4) hour peak and does not apply to primary customers who take service at or above 69 kV (i.e., customers served under SC 7 HV TOD service classification).

Low Tension Distribution System-Demand Component

Line 3 OH Transformers and Rectifiers D D03
Line 4 UG Transformers and Rectifiers D D03
Line 7 OH Lines Demand D D03
Line 8 UG Lines Demand D D03

The fixed and operating costs including federal income taxes for the above functions are subdivided to show separately the functions associated with overhead and underground line transformers and rectifiers and the overhead and underground lines (conductors). The demand component includes the transformers, rectifiers, and the overhead and underground lines of the Low Tension (secondary) System, required to supply the connected load, above a customer's minimal loading requirements. The Low Tension Overhead and Underground D03 allocation factor is the average of the non-coincident maximum class demands and individual customer billing demands at input to the low tension line transformers. No overhead or underground transformer and line demand costs were allocated to the primary voltage customers in the Commercial & Industrial SC 2, and SC 7 Large Time of Use.

Low Tension Distribution System-Customer Component

Line 5 OH Transformers and Rectifiers C C01
Line 6 UG Transformers and Rectifiers C C01
Line 9, OH Lines Customer C C01
Line 10, UG Lines Customer C C01

The costs for these functions include fixed and operating costs, together with federal income taxes. These functions are considered to be joint customer costs as distinguished from direct customer costs, since they represent the estimated costs of the minimum-sized jointly-used distribution system needed to serve the customers under the existing conditions of customer density and geographical dispersion, on the assumption of little or no use of the service by any customer. Expressed in another manner, the customer component is the cost of the smallest secondary system theoretically needed to physically connect all of the existing service points to the line transformers and rectifiers, above a customer's minimal loading requirements. The C01 allocation factor represents the functionalized book cost for the overhead and underground lines, based on the Low Tension demands. No Low Tension Distribution System-Customer

Component costs were allocated to the primary voltage customers in the Commercial & Industrial SC 2, and SC 7 Large Time of Use.

Line 11, Services – OH C C02
Line 12, Services - UG C C02

These costs represent the overhead and underground service connections fixed and operating costs, including federal income taxes. The C02 allocation factor represents the year-end book costs for overhead and underground services, allocated to service classes based on distribution kW excluding the SC4 Municipal and SC6 Dusk to Dawn Private Lighting classes, as well as the SC7 HV TOD class.

Line 13, Meters and Meter Installations C S01

The Meters and Meter Installation function includes the fixed and operating costs, together with federal income taxes, for metering equipment on customers' premises, plus meters and demand devices carried in stock. The costs for this function are considered to be direct customer costs. The S01 allocation factor is based on year-end book cost of meters and meter installations. The book cost allocation was based on a detailed study of customers' meters for each service classification. The separate installation costs for meter installations were allocated based on book costs of meters including demand devices.

Line 14, Installations on Customers' Premises C C03

The Installations on Customer Premises function includes the fixed and operating costs, together with federal income taxes, for equipment installed on customers' premises. The C03 allocation factor is based on direct book cost functionalization of installations on customers' premises and allocated to the SC 7 Primary Time of Use and Separately Metered Space Heating classes.

Line 15, Street Lighting C C04

These costs represent the Street Lighting fixed and operating costs, including federal income taxes. The C04 allocation factor represents the year-end book cost for Street Lighting based on the low tension demands for the Municipal and Private Lighting classes.

Line 16, Customer Accounting C S02

The Customer Accounting function includes the fixed (general plant) and operating costs, together with federal income taxes, for customer accounting. The operation and maintenance expenses include the sum of Account 901 Supervision, Account 902, Meter Reading Expenses; Account 903, Customer Records and Collection Expenses; and Account 905, Miscellaneous. S02 is the allocation factor developed by allocating the accounts that comprise the total customer accounting function, consisting of Account 902, Meter Reading allocated to the service classes based on the total number of meters in service; Account 903, Customer Records allocated based on the number of customers from the allocation factor K01; Account 901, Supervision and Account 905, Miscellaneous allocated based on the sum of allocations of Account 902 and Account 903. The allocated totals of Accounts 901, 902, 903 and 905 are summed by class, resulting in the S02 allocation factor.

Line 17, Uncollectibles C S03

The Uncollectibles function includes the operation and maintenance expenses for uncollectible accounts (no general plant and A&G assignment). S03 is the allocation factor representing the total uncollectible expense allocated based on 2016 revenues by class.

Line 18, Customer Service C S04

The fixed (general plant) and operating costs, including federal income taxes, represents the costs for this function. The operation and maintenance expenses include Account 906, Customer Service and Informational Expense; Account 908, Customer Assistance Expense; Account 909, Informational Advertising Expenses; Account 910, Miscellaneous Customer Expenses; Account 911, Supervision; Account 912, Demonstrating and Selling Expenses; Account 913, Advertising Expense and Account 916, Miscellaneous Selling Expense and 917, Sales Expense. S04 is the allocation factor developed by allocating the annual customer service expense on the number of customers.

Line 19, Revenues R S06 Applicable to Payroll & Miscellaneous Taxes
Line 19, Revenues R R 99

The annual total Payroll & Miscellaneous Taxes revenue function S06 is the allocation factor comprised of the State Income Tax. The State Income Tax is allocated on total kilowatt-hours.

Revenues R R99, the revenue function is non-applicable for this study.

<u>Allocation Factors Used In Table 4</u>

<u>R R01 Revenue from Sales</u>

R01 is the allocation factor for the 2016 billing determinants priced at April 2019 rates by class.

<u>R R02 Other Electric Revenues</u>

Other Electric Revenues consist of miscellaneous electric revenues.

<u>Allocation Factors Used In Table 6</u>

<u>K01 Number of Customers</u>

The K01 allocation factor is the annual number of customers by class used to develop the Customer Costs by class in **Table 6, Pages 1 – 4.**

<u>Service Classes</u>

<u>Column (1) Total Company</u> – The sum of columns (7) through (19).

<u>Column (2) Total Residential</u> – The sum of columns (7) through (9).

<u>Column (3) Total Commercial and Industrial</u> – The sum of columns (10) through (13).

<u>Column (4) Total Municipal Lighting</u> – Equals column (14).

<u>Column (5) Private Lighting</u> - The sum of Columns (15) and (16).

<u>Column (6) Primary–Time of Use</u> – The sum of Columns (17) through (19).

<u>Column (7) Residential SC 1 General</u> - Applicable to general residential customers.

<u>Column (8) Residential SC3 Time of Use (“TOU”)</u> – Time of day service applicable to residential customers with approved electric storage water heaters used for their entire water heating requirements and/or permanently installed electric space heating equipment as the sole source of space heating, excluding fireplaces, on the premises.

Column (9) Residential SC5 With Space Heating – Applicable to residential customers with electric space heating other than resistance heating, with limited exceptions.

Column (10) Commercial & Industrial SC2 Non Demand Metered Secondary - Applicable to non-residential customers with demands below 5 kW.

Column (11) Commercial & Industrial SC2 General Service Secondary - Applicable to non-residential secondary metered customers with demands in excess of 5 kW.

Column (12) Commercial & Industrial SC2 Space Heating – Separately metered service applicable to non-residential customers with 10 kW or more of permanently installed electric space heating equipment.

Column (13) Commercial & Industrial SC2 Primary – Applicable to non-residential primary metered customers with demands less than 1,000 kW.

Column (14) SC4 Municipal Lighting - Applicable to lighting of streets, highways, roadways and ways open to the public use.

Column (15) SC6 Dusk to Dawn – Applicable to outdoor lighting areas, beyond the limits of public streets, highways and road ways.

Column (16) SC6 Energy LTG – Metered or unmetered service applicable to customers who own and maintain facilities to provide outdoor lighting.

Column (17) SC7 Primary Large Time of Use – Time of use service applicable to primary metered customers with usage greater than 1,000 kW per month.

Column (18) SC7 Separately Metered Space Heating - Separately metered service applicable to non-residential customers taking service under SC 7 with 10 kW or more of permanently installed electric space heating equipment.

Column (19) SC7 HV TOD – Service applicable to non-residential customers taking service under SC 7 at high distribution voltages.

III - TABLE 1 RATE OF RETURN STATEMENT

The class allocations of the functions shown in **Table 2, Pages 1-36, Rate Base**; **Table 3 Pages 1-20, Operating Expenses**; **Table 4, Pages 1-4, Operating Revenues** and **Table 5, Pages 1-8, Federal Income Taxes,** were consolidated and tabulated in summary form on **Table 1, Pages 1-4. Line 16** is the Rate of Return on Utility Rate Base for the Total System, and for each RECO customer class. **Line 18**, the Index, is the ratio of the class return to the total system rate of return of **5.78%**. **Line 20**, the Deviation, is the extent (in percentage points) by which the actual rate of return for each customer class deviates from the total system rate of return.

IV-TABLE 2 RATE BASE

Rate Base is shown on **Table 2, Pages 1-36.** The **Total Rate Base** shown on **Table 2, Pages 33-36** is the sum of book costs for distribution Plant in Service (including Intangible Plant), Table 2, Pages 1-4, General Plant, Table 2, pages 5-8, and Plant Held for Future Use, Table 2, pages 9-12 less the corresponding Reserve for Depreciation, Table 2, pages 13-16 plus Non-Interest Bearing CWIP, Table 2, pages 17-20 (resulting in Net Plant, Table 2, pages 21-24), plus Rate Base Adjustments, Table 2, pages 25-28 plus Working Capital, Table 2, pages 29-32. These costs are comprised of the functionalized book costs.

Description of Book Cost Functionalization from workpaper Book Cost of Plant:

Intangible Plant:

Lines 2 - 4, Account 301 to Account 303, Intangible Plant

The total costs for Account 301 to Account 303 were functionalized based on general plant.

Lines 5, Total Intangible Plant

Total Intangible Plant is the sum of Line 2 through Line 4.

Production Plant:

Line 9, Account 310 through Account 346, Total Production Plant

The book costs for production plant is zero.

Transmission Plant:

Lines 12-20, Account 350 to Account 359, Transmission Plant

These costs were functionalized directly to the Transmission function and removed from the study.

Line 21, Total Transmission Plant

Total Transmission Plant is the sum of Line 12 through Line 20.

Distribution Plant:

Line 25, Account 360, Land and Land Rights

These costs for land occupied by substations were functionalized directly to the High Tension, Below 69 kV function. An adjustment for transmission and distribution (T&D) demarcation based upon the FERC and State indicators is included in Account 360.

Lines, 26-27, Accounts 361 and 362, Station Structures and Equipment-Distribution

These costs represent the substation structures and equipment plant. These costs were functionalized directly to the High Tension, Below 69 kV function.

Line 28, Account 364, Poles, Towers and Fixtures

These costs represent the book costs for Poles, Towers and Fixtures used for High Tension conductors and Low Tension conductors. The property record data for Account 365 provided the footage for Overhead Conductors broken down between primary and secondary voltages or High and Low Tension respectively. The Poles, Towers and Fixtures book cost were then multiplied by the primary and secondary percentages of the overhead conductors. The primary costs were assigned to the High Tension, Above and Below 69 kV functions. The secondary costs were subdivided into demand and customer components utilizing the Poles, Towers and Fixtures percentages from the minimum size method. An adjustment for transmission and distribution (T&D) demarcation based upon the FERC and State indicators is included in Account 364 as well as its respective reserve for depreciation and expense accounts.

Line 29, Account 365, Overhead Conductors

These costs were obtained from book cost data. The property record data for Account 365 provided the breakdown of primary and secondary voltages. The cost associated with primary voltage was assigned to the High Tension, Above and Below 69 kV functions. The secondary voltage cost was subdivided into demand and customer components utilizing the Overhead Conductor percentages from the minimum size method. An adjustment for T&D demarcation based upon the FERC and State indicators is included in Account 365, as well as in its respective reserve for depreciation and expense accounts.

Line 30, Account 366, Underground Conduit

These costs were functionalized on the same basis as Account 367, Underground Conductors as described in Account 367. An adjustment for T&D demarcation based upon the FERC and State indicators is included in Account 366, as well as in its respective reserve for depreciation and expense accounts.

Line 31, Account 367, Underground Conductors

The costs for Account 367 are obtained from book cost data. The property record data for Account 367 – provided the breakdown between primary and secondary voltages. The primary voltage costs associated with high tension was assigned to the High Tension, Above and Below 69 kV functions. The low tension (secondary voltage) costs were subdivided into demand and customer components utilizing the Underground Conductor percentages from the minimum size method. An adjustment for T&D demarcation based upon the FERC and State indicators is included in Account 367, as well as in its respective reserve for depreciation and expense accounts.

Line 32, Account 368, Line Transformers

This represents the functionalized total book cost of the overhead and underground line transformers and rectifiers. These costs were further subdivided into demand and customer components using a minimum system methodology.

Line 33, Account 369, Services

The total book cost of services was directly assigned to the overhead and underground services functions based on the Company's property records data.

Line 34, Account 370, Meters and Meter Installations

The total book cost of Meters and Meter Installations was functionalized direct to the Meters and Meter Installation function.

Line 35, Account 371, Installations on Customers' Premises

The total book cost for the installations on customer premises was assigned directly to the Installation on Customers' Premises function.

Line 36, Account 373, Street Lighting and Signal Systems

Street Lighting contains two types of accounts: Overhead and Underground. Overhead costs include the complete street lighting unit, including arm, luminaire, bulb, dusk to dawn sensor and etc. Underground includes all of the items listed above plus the fiberglass pole (or other ornamental type pole), and the wiring. These were directly assigned to the Street Lighting function.

Line 37, Total Distribution Plant

Total Distribution Plant is the sum of Line 25 through Line 36.

Line 40, Total Plant

Total Plant is the sum of Line 5, Total Intangible Plant, Line 9, Total Production Plant, Line 21, Total Transmission Plant and Line 37, Total Distribution Plant.

General Plant:

Lines 43-50, Accounts 389 to 398, General Plant

The cost of general plant was functionalized to the functions based on labor expenses. The Distribution portion of General Plant was functionalized on Distribution O&M expenses excluding rents.

Line 51, Total General Plant

Total General Plant is the sum of Line 43 through Line 50.

Future Use:

Lines 55-60, Accounts 350 to 361, Future Use of Plant

The cost of land for the future use of substation plant was functionalized directly to the High Tension, Below 69 kV function.

Line 61, Total Future Use Plant

Total Future Use is the sum of Line 55 through Line 60.

Line 64, Total Book Cost (Gross Plant)

Total Book Cost (Gross Plant) is the sum of Line 40, Total Plant, Line 51, Total General Plant and Line 61, Total Future Use Plant.

Reserve for Depreciation

The **Reserve for Depreciation** is shown by function on **Table 2, Pages 13-16.** The total costs were functionalized based on the corresponding book cost of plant. The **Retirement Work in Progress** was also functionalized based on distribution plant book cost.

Non-Interest Bearing Construction Work In Progress

The Construction Work In Progress balances by functions on which interest was not capitalized by the Company appears on **Table 2, Pages 17-20**. The costs were functionalized based on book cost of distribution and general plant.

Net Plant

Net Plant shown on **Table 2, Pages 21-24,** by function by class, is the sum of **Table 2, Pages 1-12, Plant in Service Costs,** plus Table 2 General Plant, plus Table 2, Plant Held For Future Use, less **Table 2, Pages 13-16, Reserve for Depreciation,** plus **Table 2, Pages 17-20, Non-Interest Bearing Construction Work In Progress.**

Rate Base Adjustments

The year end balance of Rate Base Adjustments is shown on **Table 2, Pages 25-28.**

Working Capital

Working Capital appears on **Table 2, Pages 29-32** and is composed of the cost of materials and supplies on hand for prepayments of operating taxes and a cash allowance for operation and maintenance expenses representing a lag of revenue collection over payments for costs incurred.

<u>Total Rate Base</u>

The **Total Rate Base** is shown on the last line of **Table 2, Pages 33-36.** The Total Rate Base is the sum of its components shown on **Table 2, Net Plant, Pages 21-24**, **Rate Base Adjustments, Pages 25-28** and **Working Capital, Pages 29-32.**

<u>V - TABLE 3 OPERATING EXPENSES</u>

Operating Expenses are shown on **Table 3, Pages 1-20. Total Operating Expenses,** shown on **Table 3, Pages 17-20** and are the sum of **Total Operation and Maintenance Expenses** and **Total Other Expenses.** Operation and Maintenance Expenses include Purchased Power and Transmission, which were identified and removed from the study, and Distribution Expenses including Administrative and General Expenses. Total Other Expenses are Payroll and Miscellaneous Taxes, Property Taxes and Depreciation Expenses.

<u>Operation and Maintenance Expenses:</u>

Table 3, Pages 1-4, Operation and Maintenance costs are derived from the Company's accounting data organized by Account. These Account total costs are transferred to the Operation and Maintenance Expense work paper including any required cost study adjustments and an allocation for Administrative and General Expenses. The Line Numbers listed below refer to the work paper titled Operation and Maintenance Expenses.

<u>Production Expenses:</u>

<u>Line 1, Accounts 500-557, Production Expenses</u>

The total production expenses were adjusted to reallocate a portion to the transmission and distribution functions according to the Power Supply Agreement ("PSA") with O&R, and the cost of energy was directly assigned to the Purchased Power Energy function. However these costs were removed from the study.

<u>Transmission Expenses:</u>

<u>Line 3, Accounts 560-572, Transmission Expenses</u>

These costs represent transmission expenses, adjusted for the transmission portion of the PSA, functionalized directly to the Transmission function. However these costs were removed from the study.

Regional/Market Expenses:

Line 5, Account 5757, Regional /Market Expenses, Operations, Facilitation, Monitoring and Compliance

These costs represent transmission expenses, adjusted for the transmission portion of the PSA, functionalized directly to the Transmission function. However these costs were removed from the study.

Distribution Expenses:

Line 8, Account 580, Supervision and Engineering

The Supervision and Engineering expense related to Operation was reallocated to all Operation-related Accounts in the Reallocation column except Account 589, Rents.

Line 9, Account 581, Load Dispatch

These costs are functionalized based on total Transmission Plant book costs.

Line 10, Account 582, Station Expenses

These costs are station equipment costs and were functionalized to High Tension Below 69 kV function based on book cost for Account 362, Station Equipment.

Line 11, Account 583, Overhead Lines

These costs were functionalized based on the functionalization of the book costs of Account 364, Poles, Towers and Fixtures and Account 365, Overhead Conductors.

Line 12, Account 584, Underground Lines

These costs functionalized based on the book costs of Account 366, Underground Conduit and Account 367, Underground Conductors.

Line 13, Account 585, Street Lighting

These costs were functionalized based on the book costs of Account 373, Street Lighting and Signal Systems.

Line 14, Account 586, Meters

These costs were functionalized direct to the Meters and Meter Installation function.

Line 15, Account 587, Customer Installation Expenses

These costs were functionalized direct to the Installation on Customers' Premises function.

Line 16, Account 588, Miscellaneous Distribution Expenses

These costs were functionalized based on the book costs of the total distribution plant.

Line 17, Account 589, Distribution Rents

These costs were adjusted to include the distribution portion of the PSA, and were functionalized based on the book cost of the total distribution plant.

Line 18, Total Distribution Operation Expense

Total Distribution Operation Expense is equal to the sum of Accounts 580 through 589.

Line 21, Total Distribution Operation Expense Less Rents

Total Distribution Operation Expense Less Rents is equal to Line 18, Total Distribution Operation Expenses less Line 17, Account 589 Distribution Rents.

Line 24, Account 592, Station Equipment

These costs were functionalized based on the book cost of Account 362, Station Equipment.

Line 25, Account 593, Overhead Lines

These costs were functionalized based on the book cost of Account 364, Poles, Towers and Fixtures; Account 365, Overhead Conductors and the overhead portion of Account 369, Services.

Line 26, Account 594, Underground Lines

These costs were functionalized based on the book cost of Account 366, Underground Conduit; Account 367, Underground Conductors and the underground portion of Account 369, Services.

Line 27, Account 596, Street Lighting

These costs were functionalized based on the book costs of Account 373, Street Lighting and Signal Systems.

Line 28, Account 597, Meters

These costs were functionalized direct to the Meters and Meter Installation function.

Line 29, Total Distribution Maintenance Expenses

The Total Distribution Maintenance Expenses is the sum of Line 24, Account 592 through Line 28, Account 597.

Line 33, Total Distribution Expenses

Total Distribution Expenses is the sum of Line 18, Total Distribution Operation Expenses and Line 29, Total Distribution Maintenance Expenses.

Line 36, Total Distribution Expenses Excluding Rents

Line 36 equals the sum of Line 21, Total Distribution Operation Expenses Less Rents and Line 29, Total Distribution Maintenance Expenses.

Customer Accounts and Customer Service and Sales Expense:

Line 38, Accounts 901, 902, 903 and 905, Customer Accounting and Collection

These costs were functionalized direct to the Customer Accounting function.

Line 39, Account 904, Uncollectibles

These costs were functionalized direct to the Uncollectibles function.

Line 40, Accounts 906-917, Customer Service and Sales Expenses

These costs were functionalized to the Customer Service and SBC/DSM functions, respectively**.** SBC and DSM are removed from the study.

Line 41, Total O&M

Total O&M is the sum of Line 1, Production Expenses, Line 3, Transmission Expenses, Line 5, Regional/Market Expenses, Line 33, Total Distribution Expenses, Line 38, Customer Accounting Expenses, Line 39, Uncollectibles and Line 40, Customer Service and Sales Expenses.

Administrative and General Expenses:

Lines 43, Accounts 920 – 935, Total Administrative and General Expenses

Company Labor was used as the basis of functionalization for Accounts 920, 921, 922, 923, 926.1 to 926.3, 929, 930.2, 931, 933 and 935. Accounts 924, 925, 928 and 930.1 were functionalized on Transmission and Distribution O&M Expenses.

Line 45, Total Unadjusted O&M

Line 45 equals the sum of Line 41 and Line 43

Line 48, Total Miscellaneous Revenue Credits

Line 48 is from the Miscellaneous Revenues Credits work paper with reversed sign to indicate a credit to expense.

Line 49, Total Adjusted O&M Expenses

Line 49 is the sum of Line 45 and Line 48.

Other Expenses:

Line 52, Depreciation and Amortization Expenses

Depreciation Expenses shown on **Table 3, Pages 5-8** were identified with each plant account or group of accounts and functionalized in proportion to the corresponding book cost functionalizations. Amortizations of other items were then added resulting in Total Depreciation and Amortization Expenses.

Line 53, Property Taxes

Property Taxes are shown on **Table 3, Pages 9-12.** Property taxes are functionalized based on total book cost of plant, (Gross Plant).

Line 54, Payroll and Miscellaneous Taxes

Payroll and Miscellaneous Taxes shown on **Table 3, Pages 13-16** include State and Local Taxes on Revenue, Payroll Taxes, TEFA Tax and State Income Tax.

Line 55, Total Other Expenses

Total Other Expenses is the sum of Depreciation and Amortization, Property Taxes and Payroll and Miscellaneous Taxes.

Line 56, Grand Total

The Grand Total tabulated on **Table 3, Pages 17-20, Total Operating Expenses,** is the sum of Line 49, Total Adjusted O&M and Line 55, Total Other Expenses.

VI - TABLE 4 OPERATING REVENUES

Operating Revenues are tabulated on **Table 4, Pages 1-4.** The **Total Operating Revenues** are calculated by the sum of **Lines 1** and **2** shown below.

Line 1, Revenues from Sales R R01

The revenues shown on **Line 1** reflect current rates, i.e. rates effective April 1, 2019.

Line 2, Other Electric Revenues R R02

Other Electric Revenues consist of miscellaneous electric revenues.

Line 4, Total Operating Revenues

The Total Operating Revenues is the sum of Line 1 and Line 2.

VII - TABLE 5 FEDERAL INCOME TAXES

Federal Income Taxes are shown on **Table 5, Pages 1** through **8**. The **Federal Income Tax Computation** shown on **Table 5, Pages 5** through and **8** was calculated at **21%** of taxable income plus **FIT Adjustments, Table 5, Pages 1** through **4.** FIT amounts by function are not the final amounts because they do not include the revenue functional amounts since they are not determined until subsequent calculations. Results are presented on a functional basis to maintain a consistent report format. The total federal income tax by class is shown on **Line 25 of Table 5, Pages 5 through 8.** Federal Income Tax Adjustments – Table 5, Pages 1 through 4. In the Development of Total FIT Adjustments work papers, each individual deduction/addition tax adjustment line item is multiplied by **21%** for FIT and is then functionalized based on cost causation. The functional results are shown on **Table 5, Pages 1** through **4 (Federal Income Tax Adjustments)**.

VIII - TABLE 6 CUSTOMER COSTS

These are electric system costs considered to be customer related and are shown by class, on **Table 6, Pages 1-4.**

Line 1, Number of Customers

The number of customers in each class from the allocation factor **K01**.

Line 3, Rate Base

The customer-related rate base is shown for each class from **Table 2.**

Line 5, Total Customer Operating Expenses

The customer-related operating expenses from **Table 3** include an amount for the allocated revenue function of total operating expenses.

Line 6, Average Monthly Cost per Customer

Line 5 divided by **Line 1** divided by 12.

Line 8, Return @ 5.78% (Customer)

The applied rate of return on rate base of **5.78**% is the Total Company Rate of Return developed in this study is shown on **Table 1, Page 1, Column (1), Line 16.**

Line 9, F.I.T. Percent On Return

The F.I.T. Percent on Return was developed, by dividing the Total Company Federal Income Tax (including Interest Synchronization), shown on **Table 1, Page 1, Column (1), Line 8** by the Total Company Utility Operating Income (return), shown on **Table 1, Page 1, Column (1), Line 12.**

Line 10, Income Tax on Return

The Return of **Line 8** multiplied by the F.I.T. Percent on Return, **Line 9** results in the Income Tax on Return on a class-by-class basis.

Line 11, Total Return and F.I.T.

The Total Return and F.I.T. is the sum of **Line 8,** Return and **Line 10,** Income Tax on Return.

Line 12, Average Monthly Cost Per Customer

Line 11 divided by **Line 1** divided by 12.

Line 14, Total Monthly Customer Cost

The Monthly Customer Cost is the sum of **Line 6** and **Line 12**.

		TOTAL COMPANY (1)	TOTAL RESIDENTIAL (2)	TOTAL C&I (3)	MUNICIPAL LIGHTING (4)	PRIVATE LIGHTING (5)
	RATE OF RETURN STATEMENT					
1	TOTAL OPERATING REVENUES	65,160,854	36,060,774	23,749,455	890,512	482,657
2						
3	OPERATING EXPENSES					
4	OPERATION & MAINTENANCE	48,992,174	31,952,421	13,998,957	601,482	458,674
5	DEPRECIATION	681,279	410,366	219,293	10,684	6,725
6	PROPERTY TAXES	561,514	334,807	183,926	7,340	4,666
7	PAYROLL & MISC. TAXES	2,701,379	1,468,810	928,101	18,709	15,616
8	FEDERAL INCOME TAX	463,172	(854,171)	1,083,524	18,168	(21,901)
9		-------------------	-------------------	-------------------	-------------------	-------------------
10	TOTAL OPERATING EXPENSES	53,399,518	33,312,232	16,413,802	656,382	463,781
11						
12	UTILITY OPERATING INCOME	11,761,336	2,748,542	7,335,653	234,130	18,877
13						
14	UTILITY RATE BASE	203,657,206	122,590,564	66,839,016	2,045,299	1,366,779
15						
16	RATE OF RETURN (%)	5.78%	2.24%	10.98%	11.45%	1.38%
17						
18	INDEX	1.00	0.39	1.90	1.98	0.24
19						
20	DEVIATION	0.00	-3.53	5.20	5.67	-4.39
21						
22	TOLERANCE BAND +10%	6.35%				
23	TOLERANCE BAND -10%	5.20%				
24						
25	REVENUE SURPLUS	5,023,545	21,691	3,910,957	131,899	17,186
26	REVENUE DEFICIENCY	4,721,059	4,634,119	0	0	86,940
		===========	===========	===========	===========	===========

		TOTAL PRIMARY (6)	RESID SC1 GENERAL (7)	RESID SC3 T.O.U. (8)	RESID SC5 W/ SP HTG (9)	C&I SC2 SEC NON DEM (10)
	RATE OF RETURN STATEMENT					
1	TOTAL OPERATING REVENUES	3,977,456	35,304,841	10,158	745,775	356,539
2						
3	OPERATING EXPENSES					
4	OPERATION & MAINTENANCE	1,980,640	31,379,691	9,677	563,052	260,383
5	DEPRECIATION	34,211	403,762	157	6,447	1,801
6	PROPERTY TAXES	30,774	329,872	108	4,828	1,140
7	PAYROLL & MISC. TAXES	270,142	1,439,523	498	28,788	12,037
8	FEDERAL INCOME TAX	237,553	(865,701)	(457)	11,986	13,010
9		------------------	------------------	------------------	------------------	------------------
10	TOTAL OPERATING EXPENSES	2,553,320	32,687,147	9,984	615,101	288,370
11						
12	UTILITY OPERATING INCOME	1,424,135	2,617,693	174	130,675	68,168
13						
14	UTILITY RATE BASE	10,815,548	120,763,024	40,259	1,787,282	432,163
15						
16	RATE OF RETURN (%)	13.17%	2.17%	0.43%	7.31%	15.77%
17						
18	INDEX	2.28	0.38	0.07	1.27	2.73
19						
20	DEVIATION	7.39	-3.61	-5.34	1.54	10.00
21						
22	TOLERANCE BAND +10%					
23	TOLERANCE BAND -10%					
24						
25	REVENUE SURPLUS	941,811	0	0	21,691	51,538
26	REVENUE DEFICIENCY	0	4,631,690	2,428	0	0
		===========	===========	===========	===========	===========

		C&I SC2 SEC GEN SERV (11)	C&I SC2 SEC SPACE HTG (12)	C&I SC2 PRIMARY GEN (13)	SC4 MUNI STR LTG (14)	SC6 DUSK TO DAWN (15)	SC6 ENERGY LTG (16)
	RATE OF RETURN STATEMENT						
1	TOTAL OPERATING REVENUES	19,983,735	832,491	2,576,690	890,512	381,245	101,412
2							
3	OPERATING EXPENSES						
4	OPERATION & MAINTENANCE	12,136,104	568,408	1,034,062	601,482	396,772	61,903
5	DEPRECIATION	191,248	8,995	17,249	10,684	5,853	873
6	PROPERTY TAXES	159,469	7,754	15,563	7,340	3,969	698
7	PAYROLL & MISC. TAXES	767,824	39,721	108,519	18,709	12,085	3,531
8	FEDERAL INCOME TAX	818,178	14,587	237,749	18,168	(26,544)	4,643
9		-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
10	TOTAL OPERATING EXPENSES	14,072,823	639,466	1,413,142	656,382	392,134	71,647
11							
12	UTILITY OPERATING INCOME	5,910,911	193,025	1,163,548	234,130	(10,889)	29,765
13							
14	UTILITY RATE BASE	58,081,463	2,816,369	5,509,021	2,045,299	1,111,940	254,838
15							
16	RATE OF RETURN (%)	10.18%	6.85%	21.12%	11.45%	-0.98%	11.68%
17							
18	INDEX	1.76	1.19	3.66	1.98	-0.17	2.02
19							
20	DEVIATION	4.40	1.08	15.35	5.67	-6.75	5.91
21							
22	TOLERANCE BAND +10%						
23	TOLERANCE BAND -10%						
24							
25	REVENUE SURPLUS	2,811,702	17,865	1,029,853	131,899	0	17,186
26	REVENUE DEFICIENCY	0	0	0	0	86,940	0
		===========	===========	===========	===========	===========	===========

		SC7 PRIMARY T.O.U. (17)	SC7 SEP MET SP HTG (18)	SC7 HV TOD (19)
	RATE OF RETURN STATEMENT			
1	TOTAL OPERATING REVENUES	3,611,114	193,026	173,315
2				
3	OPERATING EXPENSES			
4	OPERATION & MAINTENANCE	1,807,712	136,230	36,698
5	DEPRECIATION	30,984	2,618	609
6	PROPERTY TAXES	27,966	2,238	570
7	PAYROLL & MISC. TAXES	212,908	8,317	48,917
8	FEDERAL INCOME TAX	220,294	1,145	16,115
9		------------------	------------------	------------------
10	TOTAL OPERATING EXPENSES	2,299,865	150,547	102,909
11				
12	UTILITY OPERATING INCOME	1,311,250	42,479	70,407
13				
14	UTILITY RATE BASE	9,841,614	778,269	195,665
15				
16	RATE OF RETURN (%)	13.32%	5.46%	35.98%
17				
18	INDEX	2.31	0.95	6.23
19				
20	DEVIATION	7.55	-0.32	30.21
21				
22	TOLERANCE BAND +10%			
23	TOLERANCE BAND -10%			
24				
25	REVENUE SURPLUS	868,423	0	73,388
26	REVENUE DEFICIENCY	0	0	0
		===========	===========	===========

				TOTAL COMPANY (1)	TOTAL RESIDENTIAL (2)	TOTAL C&I (3)	MUNICIPAL LIGHTING (4)	PRIVATE LIGHTING (5)
	PLANT IN SERVICE							
1	HIGH TENSION ≥ 69 KV	D	D02	21,468,034	12,177,130	7,248,857	84,932	72,331
2	HIGH TENSION < 69 KV	D	D02A	177,486,705	102,139,529	60,802,080	712,394	606,697
3	TRANSFORMERS - OH DEMAND	D	D03	12,860,241	8,753,595	4,022,236	45,256	39,155
4	TRANSFORMERS - UG DEMAND	D	D03	6,855,825	4,666,562	2,144,264	24,126	20,873
5	TRANSFORMERS - OH CUSTOMER	C	C01	10,094,226	6,870,848	3,157,123	35,522	30,733
6	TRANSFORMERS - UG CUSTOMER	C	C01	6,706,262	4,564,759	2,097,486	23,600	20,418
7	OH LINES DEMAND	D	D03	19,422,006	13,219,998	6,074,528	68,347	59,133
8	UG LINES DEMAND	D	D03	1,575,023	1,072,072	492,612	5,543	4,795
9	OH LINES CUSTOMER	C	C01	21,822,178	14,853,726	6,825,219	76,793	66,440
10	UG LINES CUSTOMER	C	C01	405,792	276,211	126,918	1,428	1,235
11	SERVICES - OH	C	C02	5,786,192	3,350,492	1,994,496	0	7,350
12	SERVICES - UG	C	C02	14,862,879	8,606,343	5,123,223	0	18,881
13	METER & METER INSTALLATIONS	C	S01	9,099,500	5,966,092	3,036,208	0	20,462
14	INSTALL. ON CUSTR PREMISES	C	C03	582,742	0	0	0	0
15	STREET LIGHTING	C	C04	4,664,106	0	0	3,033,914	1,630,192
16	CUSTOMER ACCOUNTING	C	S02	1,058	921	127	0	9
17	UNCOLLECTIBLES	C	S03	0	0	0	0	0
18	CUSTOMER SERVICE	C	S04	316	275	37	0	3
19	REVENUES	R	R99	0	0	0	0	0
20				-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		239,667,834	142,028,886	80,784,577	940,597	802,984
22	TOTAL CUSTOMER	C		74,025,251	44,489,667	22,360,835	3,171,257	1,795,724
23	TOTAL REVENUE	R		0	0	0	0	0
24				-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL			313,693,085	186,518,553	103,145,412	4,111,854	2,598,709
				===========	===========	===========	===========	===========

				TOTAL PRIMARY (6)	RESID SC1 GENERAL (7)	RESID SC3 T.O.U. (8)	RESID SC5 W/ SP HTG (9)	C&I SC2 SEC NON DEM (10)
	PLANT IN SERVICE							
1	HIGH TENSION ≥ 69 KV	D	D02	1,884,784	12,012,760	3,327	161,043	34,729
2	HIGH TENSION < 69 KV	D	D02A	13,226,005	100,760,824	27,904	1,350,800	291,299
3	TRANSFORMERS - OH DEMAND	D	D03	0	8,622,385	2,665	128,545	25,540
4	TRANSFORMERS - UG DEMAND	D	D03	0	4,596,614	1,421	68,528	13,615
5	TRANSFORMERS - OH CUSTOMER	C	C01	0	6,767,859	2,092	100,897	20,047
6	TRANSFORMERS - UG CUSTOMER	C	C01	0	4,496,337	1,390	67,033	13,318
7	OH LINES DEMAND	D	D03	0	13,021,841	4,024	194,133	38,572
8	UG LINES DEMAND	D	D03	0	1,056,003	326	15,743	3,128
9	OH LINES CUSTOMER	C	C01	0	14,631,081	4,522	218,124	43,338
10	UG LINES CUSTOMER	C	C01	0	272,070	84	4,056	806
11	SERVICES - OH	C	C02	433,854	3,305,266	915	44,310	9,556
12	SERVICES - UG	C	C02	1,114,432	8,490,173	2,351	113,819	24,545
13	METER & METER INSTALLATIONS	C	S01	76,740	5,753,747	9,263	203,082	87,584
14	INSTALL. ON CUSTR PREMISES	C	C03	582,742	0	0	0	0
15	STREET LIGHTING	C	C04	0	0	0	0	0
16	CUSTOMER ACCOUNTING	C	S02	1	896	0	25	19
17	UNCOLLECTIBLES	C	S03	0	0	0	0	0
18	CUSTOMER SERVICE	C	S04	0	268	0	7	7
19	REVENUES	R	R99	0	0	0	0	0
20				-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		15,110,789	140,070,428	39,666	1,918,792	406,883
22	TOTAL CUSTOMER	C		2,207,768	43,717,697	20,617	751,353	199,219
23	TOTAL REVENUE	R		0	0	0	0	0
24				-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL			17,318,557	183,788,125	60,283	2,670,145	606,103
				===========	===========	===========	===========	===========

				C&I SC2 SEC GEN SERV (11)	C&I SC2 SEC SPACE HTG (12)	C&I SC2 PRIMARY GEN (13)	SC4 MUNI STR LTG (14)	SC6 DUSK TO DAWN (15)	SC6 ENERGY LTG (16)
	PLANT IN SERVICE								
1	HIGH TENSION ≥ 69 KV	D	D02	6,077,804	299,606	836,719	84,932	45,616	26,715
2	HIGH TENSION < 69 KV	D	D02A	50,979,500	2,513,038	7,018,243	712,394	382,621	224,076
3	TRANSFORMERS - OH DEMAND	D	D03	3,804,447	192,249	0	45,256	24,317	14,838
4	TRANSFORMERS - UG DEMAND	D	D03	2,028,160	102,489	0	24,126	12,963	7,910
5	TRANSFORMERS - OH CUSTOMER	C	C01	2,986,176	150,900	0	35,522	19,087	11,646
6	TRANSFORMERS - UG CUSTOMER	C	C01	1,983,914	100,253	0	23,600	12,681	7,737
7	OH LINES DEMAND	D	D03	5,745,615	290,342	0	68,347	36,724	22,408
8	UG LINES DEMAND	D	D03	465,939	23,545	0	5,543	2,978	1,817
9	OH LINES CUSTOMER	C	C01	6,455,658	326,222	0	76,793	41,263	25,178
10	UG LINES CUSTOMER	C	C01	120,045	6,066	0	1,428	767	468
11	SERVICES - OH	C	C02	1,672,285	82,435	230,220	0	0	7,350
12	SERVICES - UG	C	C02	4,295,566	211,750	591,362	0	0	18,881
13	METER & METER INSTALLATIONS	C	S01	2,818,176	53,893	76,555	0	0	20,462
14	INSTALL. ON CUSTR PREMISES	C	C03	0	0	0	0	0	0
15	STREET LIGHTING	C	C04	0	0	0	3,033,914	1,630,192	0
16	CUSTOMER ACCOUNTING	C	S02	104	2	1	0	8	1
17	UNCOLLECTIBLES	C	S03	0	0	0	0	0	0
18	CUSTOMER SERVICE	C	S04	29	1	0	0	3	0
19	REVENUES	R	R99	0	0	0	0	0	0
20				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		69,101,464	3,421,269	7,854,961	940,597	505,220	297,764
22	TOTAL CUSTOMER	C		20,331,955	931,523	898,138	3,171,257	1,704,000	91,724
23	TOTAL REVENUE	R		0	0	0	0	0	0
24				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL			89,433,419	4,352,791	8,753,099	4,111,854	2,209,220	389,489
				===========	===========	===========	===========	===========	===========

				SC7 PRIMARY T.O.U. (17)	SC7 SEP MET SP HTG (18)	SC7 HV TOD (19)
	PLANT IN SERVICE					
1	HIGH TENSION ≥ 69 KV	D	D02	1,470,810	106,001	307,973
2	HIGH TENSION < 69 KV	D	D02A	12,336,887	889,118	0
3	TRANSFORMERS - OH DEMAND	D	D03	0	0	0
4	TRANSFORMERS - UG DEMAND	D	D03	0	0	0
5	TRANSFORMERS - OH CUSTOMER	C	C01	0	0	0
6	TRANSFORMERS - UG CUSTOMER	C	C01	0	0	0
7	OH LINES DEMAND	D	D03	0	0	0
8	UG LINES DEMAND	D	D03	0	0	0
9	OH LINES CUSTOMER	C	C01	0	0	0
10	UG LINES CUSTOMER	C	C01	0	0	0
11	SERVICES - OH	C	C02	404,688	29,166	0
12	SERVICES - UG	C	C02	1,039,514	74,918	0
13	METER & METER INSTALLATIONS	C	S01	42,930	20,285	13,524
14	INSTALL. ON CUSTR PREMISES	C	C03	441,587	141,155	0
15	STREET LIGHTING	C	C04	0	0	0
16	CUSTOMER ACCOUNTING	C	S02	1	0	0
17	UNCOLLECTIBLES	C	S03	0	0	0
18	CUSTOMER SERVICE	C	S04	0	0	0
19	REVENUES	R	R99	0	0	0
20				-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		13,807,697	995,119	307,973
22	TOTAL CUSTOMER	C		1,928,721	265,524	13,524
23	TOTAL REVENUE	R		0	0	0
24				-------------------	-------------------	-------------------
25	TOTAL			15,736,418	1,260,643	321,497
				===========	===========	===========

				TOTAL COMPANY (1)	TOTAL RESIDENTIAL (2)	TOTAL C&I (3)	MUNICIPAL LIGHTING (4)	PRIVATE LIGHTING (5)
	GENERAL PLANT							
1	HIGH TENSION ≥ 69 KV	D	D02	306,748	173,994	103,576	1,214	1,034
2	HIGH TENSION < 69 KV	D	D02A	2,738,862	1,576,152	938,259	10,993	9,362
3	TRANSFORMERS - OH DEMAND	D	D03	47,334	32,219	14,804	167	144
4	TRANSFORMERS - UG DEMAND	D	D03	25,234	17,176	7,892	89	77
5	TRANSFORMERS - OH CUSTOMER	C	C01	37,153	25,289	11,620	131	113
6	TRANSFORMERS - UG CUSTOMER	C	C01	24,683	16,801	7,720	87	75
7	OH LINES DEMAND	D	D03	708,519	482,269	221,600	2,493	2,157
8	UG LINES DEMAND	D	D03	8,721	5,936	2,728	31	27
9	OH LINES CUSTOMER	C	C01	796,078	541,867	248,986	2,801	2,424
10	UG LINES CUSTOMER	C	C01	2,247	1,529	703	8	7
11	SERVICES - OH	C	C02	205,901	119,227	70,974	0	262
12	SERVICES - UG	C	C02	69,711	40,366	24,029	0	89
13	METER & METER INSTALLATIONS	C	S01	104,898	68,776	35,001	0	236
14	INSTALL. ON CUSTR PREMISES	C	C03	2,145	0	0	0	0
15	STREET LIGHTING	C	C04	98,285	0	0	63,933	34,353
16	CUSTOMER ACCOUNTING	C	S02	1,439,719	1,253,141	172,649	410	12,674
17	UNCOLLECTIBLES	C	S03	0	0	0	0	0
18	CUSTOMER SERVICE	C	S04	430,297	374,743	50,538	153	4,610
19	REVENUES	R	R99	0	0	0	0	0
20				-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		3,835,418	2,287,746	1,288,859	14,986	12,800
22	TOTAL CUSTOMER	C		3,211,117	2,441,740	622,219	67,522	54,842
23	TOTAL REVENUE	R		0	0	0	0	0
24				-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL			7,046,534	4,729,486	1,911,079	82,509	67,642
				===========	===========	===========	===========	===========

				TOTAL PRIMARY (6)	RESID SC1 GENERAL (7)	RESID SC3 T.O.U. (8)	RESID SC5 W/ SP HTG (9)	C&I SC2 SEC NON DEM (10)
	GENERAL PLANT							
1	HIGH TENSION ≥ 69 KV	D	D02	26,931	171,645	48	2,301	496
2	HIGH TENSION < 69 KV	D	D02A	204,095	1,554,877	431	20,845	4,495
3	TRANSFORMERS - OH DEMAND	D	D03	0	31,736	10	473	94
4	TRANSFORMERS - UG DEMAND	D	D03	0	16,918	5	252	50
5	TRANSFORMERS - OH CUSTOMER	C	C01	0	24,910	8	371	74
6	TRANSFORMERS - UG CUSTOMER	C	C01	0	16,549	5	247	49
7	OH LINES DEMAND	D	D03	0	475,040	147	7,082	1,407
8	UG LINES DEMAND	D	D03	0	5,847	2	87	17
9	OH LINES CUSTOMER	C	C01	0	533,745	165	7,957	1,581
10	UG LINES CUSTOMER	C	C01	0	1,507	0	22	4
11	SERVICES - OH	C	C02	15,439	117,618	33	1,577	340
12	SERVICES - UG	C	C02	5,227	39,821	11	534	115
13	METER & METER INSTALLATIONS	C	S01	885	66,328	107	2,341	1,010
14	INSTALL. ON CUSTR PREMISES	C	C03	2,145	0	0	0	0
15	STREET LIGHTING	C	C04	0	0	0	0	0
16	CUSTOMER ACCOUNTING	C	S02	845	1,219,306	341	33,493	26,439
17	UNCOLLECTIBLES	C	S03	0	0	0	0	0
18	CUSTOMER SERVICE	C	S04	253	364,664	100	9,979	8,943
19	REVENUES	R	R99	0	0	0	0	0
20				-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		231,026	2,256,063	642	31,040	6,560
22	TOTAL CUSTOMER	C		24,793	2,384,448	770	56,522	38,555
23	TOTAL REVENUE	R		0	0	0	0	0
24				-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL			255,819	4,640,512	1,412	87,562	45,115
				===========	===========	===========	===========	===========

				C&I SC2 SEC GEN SERV (11)	C&I SC2 SEC SPACE HTG (12)	C&I SC2 PRIMARY GEN (13)	SC4 MUNI STR LTG (14)	SC6 DUSK TO DAWN (15)	SC6 ENERGY LTG (16)
	GENERAL PLANT								
1	HIGH TENSION ≥ 69 KV	D	D02	86,843	4,281	11,956	1,214	652	382
2	HIGH TENSION < 69 KV	D	D02A	786,683	38,780	108,301	10,993	5,904	3,458
3	TRANSFORMERS - OH DEMAND	D	D03	14,003	708	0	167	90	55
4	TRANSFORMERS - UG DEMAND	D	D03	7,465	377	0	89	48	29
5	TRANSFORMERS - OH CUSTOMER	C	C01	10,991	555	0	131	70	43
6	TRANSFORMERS - UG CUSTOMER	C	C01	7,302	369	0	87	47	28
7	OH LINES DEMAND	D	D03	209,601	10,592	0	2,493	1,340	817
8	UG LINES DEMAND	D	D03	2,580	130	0	31	16	10
9	OH LINES CUSTOMER	C	C01	235,504	11,901	0	2,801	1,505	918
10	UG LINES CUSTOMER	C	C01	665	34	0	8	4	3
11	SERVICES - OH	C	C02	59,508	2,933	8,192	0	0	262
12	SERVICES - UG	C	C02	20,147	993	2,774	0	0	89
13	METER & METER INSTALLATIONS	C	S01	32,487	621	883	0	0	236
14	INSTALL. ON CUSTR PREMISES	C	C03	0	0	0	0	0	0
15	STREET LIGHTING	C	C04	0	0	0	63,933	34,353	0
16	CUSTOMER ACCOUNTING	C	S02	141,491	3,215	1,505	410	10,681	1,993
17	UNCOLLECTIBLES	C	S03	0	0	0	0	0	0
18	CUSTOMER SERVICE	C	S04	40,129	989	477	153	3,992	618
19	REVENUES	R	R99	0	0	0	0	0	0
20				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		1,107,175	54,867	120,257	14,986	8,050	4,751
22	TOTAL CUSTOMER	C		548,224	21,610	13,830	67,522	50,652	4,190
23	TOTAL REVENUE	R		0	0	0	0	0	0
24				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL			1,655,400	76,478	134,087	82,509	58,701	8,941
				===========	===========	===========	===========	===========	===========

				SC7 PRIMARY T.O.U. (17)	SC7 SEP MET SP HTG (18)	SC7 HV TOD (19)
	GENERAL PLANT					
1	HIGH TENSION ≥ 69 KV	D	D02	21,016	1,515	4,400
2	HIGH TENSION < 69 KV	D	D02A	190,375	13,720	0
3	TRANSFORMERS - OH DEMAND	D	D03	0	0	0
4	TRANSFORMERS - UG DEMAND	D	D03	0	0	0
5	TRANSFORMERS - OH CUSTOMER	C	C01	0	0	0
6	TRANSFORMERS - UG CUSTOMER	C	C01	0	0	0
7	OH LINES DEMAND	D	D03	0	0	0
8	UG LINES DEMAND	D	D03	0	0	0
9	OH LINES CUSTOMER	C	C01	0	0	0
10	UG LINES CUSTOMER	C	C01	0	0	0
11	SERVICES - OH	C	C02	14,401	1,038	0
12	SERVICES - UG	C	C02	4,876	351	0
13	METER & METER INSTALLATIONS	C	S01	495	234	156
14	INSTALL. ON CUSTR PREMISES	C	C03	1,625	520	0
15	STREET LIGHTING	C	C04	0	0	0
16	CUSTOMER ACCOUNTING	C	S02	761	60	24
17	UNCOLLECTIBLES	C	S03	0	0	0
18	CUSTOMER SERVICE	C	S04	230	18	6
19	REVENUES	R	R99	0	0	0
20				-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		211,391	15,235	4,400
22	TOTAL CUSTOMER	C		22,388	2,220	186
23	TOTAL REVENUE	R		0	0	0
24				-------------------	-------------------	-------------------
25	TOTAL			233,778	17,455	4,586
				===========	===========	===========

				TOTAL COMPANY (1)	TOTAL RESIDENTIAL (2)	TOTAL C&I (3)	MUNICIPAL LIGHTING (4)	PRIVATE LIGHTING (5)
	PLANT HELD FOR FUTURE USE							
1	HIGH TENSION ≥ 69 KV	D	D02	0	0	0	0	0
2	HIGH TENSION < 69 KV	D	D02A	208,709	120,107	71,498	838	713
3	TRANSFORMERS - OH DEMAND	D	D03	0	0	0	0	0
4	TRANSFORMERS - UG DEMAND	D	D03	0	0	0	0	0
5	TRANSFORMERS - OH CUSTOMER	C	C01	0	0	0	0	0
6	TRANSFORMERS - UG CUSTOMER	C	C01	0	0	0	0	0
7	OH LINES DEMAND	D	D03	0	0	0	0	0
8	UG LINES DEMAND	D	D03	0	0	0	0	0
9	OH LINES CUSTOMER	C	C01	0	0	0	0	0
10	UG LINES CUSTOMER	C	C01	0	0	0	0	0
11	SERVICES - OH	C	C02	0	0	0	0	0
12	SERVICES - UG	C	C02	0	0	0	0	0
13	METER & METER INSTALLATIONS	C	S01	0	0	0	0	0
14	INSTALL. ON CUSTR PREMISES	C	C03	0	0	0	0	0
15	STREET LIGHTING	C	C04	0	0	0	0	0
16	CUSTOMER ACCOUNTING	C	S02	0	0	0	0	0
17	UNCOLLECTIBLES	C	S03	0	0	0	0	0
18	CUSTOMER SERVICE	C	S04	0	0	0	0	0
19	REVENUES	R	R99	0	0	0	0	0
20				-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		208,709	120,107	71,498	838	713
22	TOTAL CUSTOMER	C		0	0	0	0	0
23	TOTAL REVENUE	R		0	0	0	0	0
24				-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL			208,709	120,107	71,498	838	713
				=============	============	===========	===========	===========

				TOTAL PRIMARY (6)	RESID SC1 GENERAL (7)	RESID SC3 T.O.U. (8)	RESID SC5 W/ SP HTG (9)	C&I SC2 SEC NON DEM (10)
	PLANT HELD FOR FUTURE USE							
1	HIGH TENSION ≥ 69 KV	D	D02	0	0	0	0	0
2	HIGH TENSION < 69 KV	D	D02A	15,553	118,486	33	1,588	343
3	TRANSFORMERS - OH DEMAND	D	D03	0	0	0	0	0
4	TRANSFORMERS - UG DEMAND	D	D03	0	0	0	0	0
5	TRANSFORMERS - OH CUSTOMER	C	C01	0	0	0	0	0
6	TRANSFORMERS - UG CUSTOMER	C	C01	0	0	0	0	0
7	OH LINES DEMAND	D	D03	0	0	0	0	0
8	UG LINES DEMAND	D	D03	0	0	0	0	0
9	OH LINES CUSTOMER	C	C01	0	0	0	0	0
10	UG LINES CUSTOMER	C	C01	0	0	0	0	0
11	SERVICES - OH	C	C02	0	0	0	0	0
12	SERVICES - UG	C	C02	0	0	0	0	0
13	METER & METER INSTALLATIONS	C	S01	0	0	0	0	0
14	INSTALL. ON CUSTR PREMISES	C	C03	0	0	0	0	0
15	STREET LIGHTING	C	C04	0	0	0	0	0
16	CUSTOMER ACCOUNTING	C	S02	0	0	0	0	0
17	UNCOLLECTIBLES	C	S03	0	0	0	0	0
18	CUSTOMER SERVICE	C	S04	0	0	0	0	0
19	REVENUES	R	R99	0	0	0	0	0
20				-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		15,553	118,486	33	1,588	343
22	TOTAL CUSTOMER	C		0	0	0	0	0
23	TOTAL REVENUE	R		0	0	0	0	0
24				-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL			15,553	118,486	33	1,588	343
				===========	===========	===========	===========	===========

				C&I SC2 SEC GEN SERV (11)	C&I SC2 SEC SPACE HTG (12)	C&I SC2 PRIMARY GEN (13)	SC4 MUNI STR LTG (14)	SC6 DUSK TO DAWN (15)	SC6 ENERGY LTG (16)
	PLANT HELD FOR FUTURE USE								
1	HIGH TENSION ≥ 69 KV	D	D02	0	0	0	0	0	0
2	HIGH TENSION < 69 KV	D	D02A	59,948	2,955	8,253	838	450	263
3	TRANSFORMERS - OH DEMAND	D	D03	0	0	0	0	0	0
4	TRANSFORMERS - UG DEMAND	D	D03	0	0	0	0	0	0
5	TRANSFORMERS - OH CUSTOMER	C	C01	0	0	0	0	0	0
6	TRANSFORMERS - UG CUSTOMER	C	C01	0	0	0	0	0	0
7	OH LINES DEMAND	D	D03	0	0	0	0	0	0
8	UG LINES DEMAND	D	D03	0	0	0	0	0	0
9	OH LINES CUSTOMER	C	C01	0	0	0	0	0	0
10	UG LINES CUSTOMER	C	C01	0	0	0	0	0	0
11	SERVICES - OH	C	C02	0	0	0	0	0	0
12	SERVICES - UG	C	C02	0	0	0	0	0	0
13	METER & METER INSTALLATIONS	C	S01	0	0	0	0	0	0
14	INSTALL. ON CUSTR PREMISES	C	C03	0	0	0	0	0	0
15	STREET LIGHTING	C	C04	0	0	0	0	0	0
16	CUSTOMER ACCOUNTING	C	S02	0	0	0	0	0	0
17	UNCOLLECTIBLES	C	S03	0	0	0	0	0	0
18	CUSTOMER SERVICE	C	S04	0	0	0	0	0	0
19	REVENUES	R	R99	0	0	0	0	0	0
20				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		59,948	2,955	8,253	838	450	263
22	TOTAL CUSTOMER	C		0	0	0	0	0	0
23	TOTAL REVENUE	R		0	0	0	0	0	0
24				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL			59,948	2,955	8,253	838	450	263
				===========	===========	===========	===========	===========	===========

				SC7 PRIMARY T.O.U. (17)	SC7 SEP MET SP HTG (18)	SC7 HV TOD (19)
	PLANT HELD FOR FUTURE USE					
1	HIGH TENSION ≥ 69 KV	D	D02	0	0	0
2	HIGH TENSION < 69 KV	D	D02A	14,507	1,046	0
3	TRANSFORMERS - OH DEMAND	D	D03	0	0	0
4	TRANSFORMERS - UG DEMAND	D	D03	0	0	0
5	TRANSFORMERS - OH CUSTOMER	C	C01	0	0	0
6	TRANSFORMERS - UG CUSTOMER	C	C01	0	0	0
7	OH LINES DEMAND	D	D03	0	0	0
8	UG LINES DEMAND	D	D03	0	0	0
9	OH LINES CUSTOMER	C	C01	0	0	0
10	UG LINES CUSTOMER	C	C01	0	0	0
11	SERVICES - OH	C	C02	0	0	0
12	SERVICES - UG	C	C02	0	0	0
13	METER & METER INSTALLATIONS	C	S01	0	0	0
14	INSTALL. ON CUSTR PREMISES	C	C03	0	0	0
15	STREET LIGHTING	C	C04	0	0	0
16	CUSTOMER ACCOUNTING	C	S02	0	0	0
17	UNCOLLECTIBLES	C	S03	0	0	0
18	CUSTOMER SERVICE	C	S04	0	0	0
19	REVENUES	R	R99	0	0	0
20				-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		14,507	1,046	0
22	TOTAL CUSTOMER	C		0	0	0
23	TOTAL REVENUE	R		0	0	0
24				-------------------	-------------------	-------------------
25	TOTAL			14,507	1,046	0
				===========	===========	===========

				TOTAL COMPANY (1)	TOTAL RESIDENTIAL (2)	TOTAL C&I (3)	MUNICIPAL LIGHTING (4)	PRIVATE LIGHTING (5)
	ACCUM. PROV. FOR DEPRECIATION							
1	HIGH TENSION ≥ 69 KV	D	D02	5,378,385	3,050,735	1,816,056	21,278	18,121
2	HIGH TENSION < 69 KV	D	D02A	39,525,725	22,746,149	13,540,430	158,648	135,110
3	TRANSFORMERS - OH DEMAND	D	D03	3,275,529	2,229,558	1,024,472	11,527	9,973
4	TRANSFORMERS - UG DEMAND	D	D03	1,746,192	1,188,583	546,148	6,145	5,316
5	TRANSFORMERS - OH CUSTOMER	C	C01	2,571,019	1,750,019	804,125	9,048	7,828
6	TRANSFORMERS - UG CUSTOMER	C	C01	1,708,098	1,162,653	534,234	6,011	5,201
7	OH LINES DEMAND	D	D03	4,417,507	3,006,869	1,381,642	15,545	13,450
8	UG LINES DEMAND	D	D03	395,241	269,029	123,618	1,391	1,203
9	OH LINES CUSTOMER	C	C01	4,963,422	3,378,458	1,552,386	17,466	15,112
10	UG LINES CUSTOMER	C	C01	101,831	69,313	31,849	358	310
11	SERVICES - OH	C	C02	2,268,593	1,313,628	781,982	0	2,882
12	SERVICES - UG	C	C02	5,688,407	3,293,869	1,960,789	0	7,226
13	METER & METER INSTALLATIONS	C	S01	1,045,604	685,551	348,884	0	2,351
14	INSTALL. ON CUSTR PREMISES	C	C03	190,467	0	0	0	0
15	STREET LIGHTING	C	C04	1,922,277	0	0	1,250,405	671,872
16	CUSTOMER ACCOUNTING	C	S02	435,856	379,372	52,267	124	3,837
17	UNCOLLECTIBLES	C	S03	0	0	0	0	0
18	CUSTOMER SERVICE	C	S04	130,267	113,448	15,300	46	1,396
19	REVENUES	R	R99	0	0	0	0	0
20				-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		54,738,579	32,490,923	18,432,365	214,534	183,173
22	TOTAL CUSTOMER	C		21,025,840	12,146,311	6,081,817	1,283,459	718,013
23	TOTAL REVENUE	R		0	0	0	0	0
24				-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL			75,764,419	44,637,234	24,514,182	1,497,992	901,186
				===========	===========	===========	===========	===========

				TOTAL PRIMARY (6)	RESID SC1 GENERAL (7)	RESID SC3 T.O.U. (8)	RESID SC5 W/ SP HTG (9)	C&I SC2 SEC NON DEM (10)
	ACCUM. PROV. FOR DEPRECIATION							
1	HIGH TENSION ≥ 69 KV	D	D02	472,195	3,009,556	833	40,346	8,701
2	HIGH TENSION < 69 KV	D	D02A	2,945,389	22,439,116	6,214	300,819	64,871
3	TRANSFORMERS - OH DEMAND	D	D03	0	2,196,139	679	32,741	6,505
4	TRANSFORMERS - UG DEMAND	D	D03	0	1,170,767	362	17,454	3,468
5	TRANSFORMERS - OH CUSTOMER	C	C01	0	1,723,787	533	25,699	5,106
6	TRANSFORMERS - UG CUSTOMER	C	C01	0	1,145,226	354	17,073	3,392
7	OH LINES DEMAND	D	D03	0	2,961,799	915	44,155	8,773
8	UG LINES DEMAND	D	D03	0	264,997	82	3,951	785
9	OH LINES CUSTOMER	C	C01	0	3,327,818	1,028	49,612	9,857
10	UG LINES CUSTOMER	C	C01	0	68,274	21	1,018	202
11	SERVICES - OH	C	C02	170,101	1,295,896	359	17,373	3,746
12	SERVICES - UG	C	C02	426,522	3,249,408	900	43,562	9,394
13	METER & METER INSTALLATIONS	C	S01	8,818	661,151	1,064	23,336	10,064
14	INSTALL. ON CUSTR PREMISES	C	C03	190,467	0	0	0	0
15	STREET LIGHTING	C	C04	0	0	0	0	0
16	CUSTOMER ACCOUNTING	C	S02	256	369,129	103	10,140	8,004
17	UNCOLLECTIBLES	C	S03	0	0	0	0	0
18	CUSTOMER SERVICE	C	S04	77	110,397	30	3,021	2,707
19	REVENUES	R	R99	0	0	0	0	0
20				-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		3,417,584	32,042,372	9,085	439,466	93,103
22	TOTAL CUSTOMER	C		796,240	11,951,085	4,393	190,833	52,473
23	TOTAL REVENUE	R		0	0	0	0	0
24				-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL			4,213,824	43,993,457	13,478	630,298	145,576
				===========	===========	===========	===========	===========

				C&I SC2 SEC GEN SERV (11)	C&I SC2 SEC SPACE HTG (12)	C&I SC2 PRIMARY GEN (13)	SC4 MUNI STR LTG (14)	SC6 DUSK TO DAWN (15)	SC6 ENERGY LTG (16)
	ACCUM. PROV. FOR DEPRECIATION								
1	HIGH TENSION ≥ 69 KV	D	D02	1,522,672	75,060	209,623	21,278	11,428	6,693
2	HIGH TENSION < 69 KV	D	D02A	11,352,973	559,646	1,562,940	158,648	85,208	49,901
3	TRANSFORMERS - OH DEMAND	D	D03	969,000	48,966	0	11,527	6,194	3,779
4	TRANSFORMERS - UG DEMAND	D	D03	516,576	26,104	0	6,145	3,302	2,015
5	TRANSFORMERS - OH CUSTOMER	C	C01	760,585	38,434	0	9,048	4,861	2,966
6	TRANSFORMERS - UG CUSTOMER	C	C01	505,307	25,535	0	6,011	3,230	1,971
7	OH LINES DEMAND	D	D03	1,306,832	66,038	0	15,545	8,353	5,097
8	UG LINES DEMAND	D	D03	116,924	5,909	0	1,391	747	456
9	OH LINES CUSTOMER	C	C01	1,468,330	74,199	0	17,466	9,385	5,727
10	UG LINES CUSTOMER	C	C01	30,125	1,522	0	358	193	117
11	SERVICES - OH	C	C02	655,653	32,320	90,262	0	0	2,882
12	SERVICES - UG	C	C02	1,644,024	81,042	226,329	0	0	7,226
13	METER & METER INSTALLATIONS	C	S01	323,831	6,193	8,797	0	0	2,351
14	INSTALL. ON CUSTR PREMISES	C	C03	0	0	0	0	0	0
15	STREET LIGHTING	C	C04	0	0	0	1,250,405	671,872	0
16	CUSTOMER ACCOUNTING	C	S02	42,834	973	456	124	3,234	603
17	UNCOLLECTIBLES	C	S03	0	0	0	0	0	0
18	CUSTOMER SERVICE	C	S04	12,149	299	144	46	1,208	187
19	REVENUES	R	R99	0	0	0	0	0	0
20				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		15,784,977	781,722	1,772,563	214,534	115,232	67,941
22	TOTAL CUSTOMER	C		5,442,837	260,518	325,988	1,283,459	693,982	24,031
23	TOTAL REVENUE	R		0	0	0	0	0	0
24				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL			21,227,813	1,042,241	2,098,552	1,497,992	809,215	91,972
				===========	===========	===========	===========	===========	===========

				SC7 PRIMARY T.O.U. (17)	SC7 SEP MET SP HTG (18)	SC7 HV TOD (19)
	ACCUM. PROV. FOR DEPRECIATION					
1	HIGH TENSION ≥ 69 KV	D	D02	368,482	26,556	77,156
2	HIGH TENSION < 69 KV	D	D02A	2,747,385	198,004	0
3	TRANSFORMERS - OH DEMAND	D	D03	0	0	0
4	TRANSFORMERS - UG DEMAND	D	D03	0	0	0
5	TRANSFORMERS - OH CUSTOMER	C	C01	0	0	0
6	TRANSFORMERS - UG CUSTOMER	C	C01	0	0	0
7	OH LINES DEMAND	D	D03	0	0	0
8	UG LINES DEMAND	D	D03	0	0	0
9	OH LINES CUSTOMER	C	C01	0	0	0
10	UG LINES CUSTOMER	C	C01	0	0	0
11	SERVICES - OH	C	C02	158,666	11,435	0
12	SERVICES - UG	C	C02	397,849	28,673	0
13	METER & METER INSTALLATIONS	C	S01	4,933	2,331	1,554
14	INSTALL. ON CUSTR PREMISES	C	C03	144,331	46,136	0
15	STREET LIGHTING	C	C04	0	0	0
16	CUSTOMER ACCOUNTING	C	S02	231	18	7
17	UNCOLLECTIBLES	C	S03	0	0	0
18	CUSTOMER SERVICE	C	S04	70	5	2
19	REVENUES	R	R99	0	0	0
20				-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		3,115,867	224,560	77,156
22	TOTAL CUSTOMER	C		706,079	88,598	1,563
23	TOTAL REVENUE	R		0	0	0
24				-------------------	-------------------	-------------------
25	TOTAL			3,821,946	313,158	78,719
				===========	===========	===========

				TOTAL COMPANY (1)	TOTAL RESIDENTIAL (2)	TOTAL C&I (3)	MUNICIPAL LIGHTING (4)	PRIVATE LIGHTING (5)
	NON-INTEREST BEARING CWIP							
1	HIGH TENSION ≥ 69 KV	D	D02	48,622	27,580	16,418	192	164
2	HIGH TENSION < 69 KV	D	D02A	404,857	232,986	138,693	1,625	1,384
3	TRANSFORMERS - OH DEMAND	D	D03	27,195	18,511	8,506	96	83
4	TRANSFORMERS - UG DEMAND	D	D03	14,498	9,868	4,534	51	44
5	TRANSFORMERS - OH CUSTOMER	C	C01	21,346	14,530	6,676	75	65
6	TRANSFORMERS - UG CUSTOMER	C	C01	14,182	9,653	4,436	50	43
7	OH LINES DEMAND	D	D03	50,091	34,096	15,667	176	153
8	UG LINES DEMAND	D	D03	3,372	2,295	1,055	12	10
9	OH LINES CUSTOMER	C	C01	56,281	38,309	17,603	198	171
10	UG LINES CUSTOMER	C	C01	869	591	272	3	3
11	SERVICES - OH	C	C02	14,850	8,599	5,119	0	19
12	SERVICES - UG	C	C02	31,643	18,323	10,907	0	40
13	METER & METER INSTALLATIONS	C	S01	20,254	13,279	6,758	0	46
14	INSTALL. ON CUSTR PREMISES	C	C03	1,232	0	0	0	0
15	STREET LIGHTING	C	C04	11,012	0	0	7,163	3,849
16	CUSTOMER ACCOUNTING	C	S02	20,387	17,745	2,445	6	179
17	UNCOLLECTIBLES	C	S03	0	0	0	0	0
18	CUSTOMER SERVICE	C	S04	6,093	5,307	716	2	65
19	REVENUES	R	R99	0	0	0	0	0
20				-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		548,636	325,336	184,872	2,152	1,837
22	TOTAL CUSTOMER	C		198,148	126,335	54,931	7,497	4,480
23	TOTAL REVENUE	R		0	0	0	0	0
24				-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL			746,784	451,671	239,803	9,649	6,318
				===========	===========	===========	===========	===========

				TOTAL PRIMARY (6)	RESID SC1 GENERAL (7)	RESID SC3 T.O.U. (8)	RESID SC5 W/ SP HTG (9)	C&I SC2 SEC NON DEM (10)
	NON-INTEREST BEARING CWIP							
1	HIGH TENSION ≥ 69 KV	D	D02	4,269	27,207	8	365	79
2	HIGH TENSION < 69 KV	D	D02A	30,169	229,841	64	3,081	664
3	TRANSFORMERS - OH DEMAND	D	D03	0	18,234	6	272	54
4	TRANSFORMERS - UG DEMAND	D	D03	0	9,720	3	145	29
5	TRANSFORMERS - OH CUSTOMER	C	C01	0	14,312	4	213	42
6	TRANSFORMERS - UG CUSTOMER	C	C01	0	9,508	3	142	28
7	OH LINES DEMAND	D	D03	0	33,584	10	501	99
8	UG LINES DEMAND	D	D03	0	2,261	1	34	7
9	OH LINES CUSTOMER	C	C01	0	37,735	12	563	112
10	UG LINES CUSTOMER	C	C01	0	582	0	9	2
11	SERVICES - OH	C	C02	1,113	8,483	2	114	25
12	SERVICES - UG	C	C02	2,373	18,075	5	242	52
13	METER & METER INSTALLATIONS	C	S01	171	12,807	21	452	195
14	INSTALL. ON CUSTR PREMISES	C	C03	1,232	0	0	0	0
15	STREET LIGHTING	C	C04	0	0	0	0	0
16	CUSTOMER ACCOUNTING	C	S02	12	17,266	5	474	374
17	UNCOLLECTIBLES	C	S03	0	0	0	0	0
18	CUSTOMER SERVICE	C	S04	4	5,164	1	141	127
19	REVENUES	R	R99	0	0	0	0	0
20				-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		34,438	320,848	91	4,397	932
22	TOTAL CUSTOMER	C		4,905	123,932	53	2,350	957
23	TOTAL REVENUE	R		0	0	0	0	0
24				-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL			39,343	444,780	144	6,747	1,889
				===========	===========	===========	===========	===========

				C&I SC2 SEC GEN SERV (11)	C&I SC2 SEC SPACE HTG (12)	C&I SC2 PRIMARY GEN (13)	SC4 MUNI STR LTG (14)	SC6 DUSK TO DAWN (15)	SC6 ENERGY LTG (16)
	NON-INTEREST BEARING CWIP								
1	HIGH TENSION ≥ 69 KV	D	D02	13,765	679	1,895	192	103	61
2	HIGH TENSION < 69 KV	D	D02A	116,287	5,732	16,009	1,625	873	511
3	TRANSFORMERS - OH DEMAND	D	D03	8,045	407	0	96	51	31
4	TRANSFORMERS - UG DEMAND	D	D03	4,289	217	0	51	27	17
5	TRANSFORMERS - OH CUSTOMER	C	C01	6,315	319	0	75	40	25
6	TRANSFORMERS - UG CUSTOMER	C	C01	4,195	212	0	50	27	16
7	OH LINES DEMAND	D	D03	14,818	749	0	176	95	58
8	UG LINES DEMAND	D	D03	998	50	0	12	6	4
9	OH LINES CUSTOMER	C	C01	16,650	841	0	198	106	65
10	UG LINES CUSTOMER	C	C01	257	13	0	3	2	1
11	SERVICES - OH	C	C02	4,292	212	591	0	0	19
12	SERVICES - UG	C	C02	9,145	451	1,259	0	0	40
13	METER & METER INSTALLATIONS	C	S01	6,273	120	170	0	0	46
14	INSTALL. ON CUSTR PREMISES	C	C03	0	0	0	0	0	0
15	STREET LIGHTING	C	C04	0	0	0	7,163	3,849	0
16	CUSTOMER ACCOUNTING	C	S02	2,004	46	21	6	151	28
17	UNCOLLECTIBLES	C	S03	0	0	0	0	0	0
18	CUSTOMER SERVICE	C	S04	568	14	7	2	57	9
19	REVENUES	R	R99	0	0	0	0	0	0
20				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		158,203	7,833	17,904	2,152	1,156	681
22	TOTAL CUSTOMER	C		49,698	2,227	2,048	7,497	4,232	249
23	TOTAL REVENUE	R		0	0	0	0	0	0
24				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL			207,901	10,061	19,952	9,649	5,388	930
				===========	===========	===========	===========	===========	===========

				SC7 PRIMARY T.O.U. (17)	SC7 SEP MET SP HTG (18)	SC7 HV TOD (19)
	NON-INTEREST BEARING CWIP					
1	HIGH TENSION ≥ 69 KV	D	D02	3,331	240	698
2	HIGH TENSION < 69 KV	D	D02A	28,141	2,028	0
3	TRANSFORMERS - OH DEMAND	D	D03	0	0	0
4	TRANSFORMERS - UG DEMAND	D	D03	0	0	0
5	TRANSFORMERS - OH CUSTOMER	C	C01	0	0	0
6	TRANSFORMERS - UG CUSTOMER	C	C01	0	0	0
7	OH LINES DEMAND	D	D03	0	0	0
8	UG LINES DEMAND	D	D03	0	0	0
9	OH LINES CUSTOMER	C	C01	0	0	0
10	UG LINES CUSTOMER	C	C01	0	0	0
11	SERVICES - OH	C	C02	1,039	75	0
12	SERVICES - UG	C	C02	2,213	159	0
13	METER & METER INSTALLATIONS	C	S01	96	45	30
14	INSTALL. ON CUSTR PREMISES	C	C03	934	298	0
15	STREET LIGHTING	C	C04	0	0	0
16	CUSTOMER ACCOUNTING	C	S02	11	1	0
17	UNCOLLECTIBLES	C	S03	0	0	0
18	CUSTOMER SERVICE	C	S04	3	0	0
19	REVENUES	R	R99	0	0	0
20				-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		31,472	2,268	698
22	TOTAL CUSTOMER	C		4,295	579	31
23	TOTAL REVENUE	R		0	0	0
24				-------------------	-------------------	-------------------
25	TOTAL			35,767	2,847	728
				===========	===========	===========

			TOTAL COMPANY (1)	TOTAL RESIDENTIAL (2)	TOTAL C&I (3)	MUNICIPAL LIGHTING (4)	PRIVATE LIGHTING (5)
	NET PLANT						
1	HIGH TENSION ≥ 69 KV	D	16,445,020	9,327,968	5,552,795	65,060	55,407
2	HIGH TENSION < 69 KV	D	141,313,407	81,322,625	48,410,100	567,202	483,047
3	TRANSFORMERS - OH DEMAND	D	9,659,241	6,574,766	3,021,075	33,991	29,409
4	TRANSFORMERS - UG DEMAND	D	5,149,364	3,505,023	1,610,542	18,121	15,678
5	TRANSFORMERS - OH CUSTOMER	C	7,581,705	5,160,648	2,371,294	26,680	23,083
6	TRANSFORMERS - UG CUSTOMER	C	5,037,029	3,428,560	1,575,407	17,725	15,336
7	OH LINES DEMAND	D	15,763,110	10,729,494	4,930,153	55,471	47,993
8	UG LINES DEMAND	D	1,191,875	811,275	372,777	4,194	3,629
9	OH LINES CUSTOMER	C	17,711,116	12,055,445	5,539,421	62,326	53,924
10	UG LINES CUSTOMER	C	307,077	209,018	96,043	1,081	935
11	SERVICES - OH	C	3,738,350	2,164,690	1,288,607	0	4,749
12	SERVICES - UG	C	9,275,825	5,371,163	3,197,370	0	11,783
13	METER & METER INSTALLATIONS	C	8,179,047	5,362,596	2,729,082	0	18,392
14	INSTALL. ON CUSTR PREMISES	C	395,653	0	0	0	0
15	STREET LIGHTING	C	2,851,126	0	0	1,854,605	996,522
16	CUSTOMER ACCOUNTING	C	1,025,308	892,435	122,953	292	9,026
17	UNCOLLECTIBLES	C	0	0	0	0	0
18	CUSTOMER SERVICE	C	306,440	266,876	35,991	109	3,283
19	REVENUES	R	0	0	0	0	0
20			-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D	189,522,018	112,271,152	63,897,441	744,039	635,163
22	TOTAL CUSTOMER	C	56,408,676	34,911,431	16,956,168	1,962,818	1,137,033
23	TOTAL REVENUE	R	0	0	0	0	0
24			-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL		245,930,694	147,182,583	80,853,610	2,706,857	1,772,196
			===========	===========	===========	===========	===========

			TOTAL PRIMARY (6)	RESID SC1 GENERAL (7)	RESID SC3 T.O.U. (8)	RESID SC5 W/ SP HTG (9)	C&I SC2 SEC NON DEM (10)
	NET PLANT						
1	HIGH TENSION ≥ 69 KV	D	1,443,789	9,202,057	2,548	123,363	26,603
2	HIGH TENSION < 69 KV	D	10,530,433	80,224,913	22,217	1,075,496	231,930
3	TRANSFORMERS - OH DEMAND	D	0	6,476,216	2,001	96,549	19,183
4	TRANSFORMERS - UG DEMAND	D	0	3,452,486	1,067	51,471	10,226
5	TRANSFORMERS - OH CUSTOMER	C	0	5,083,294	1,571	75,783	15,057
6	TRANSFORMERS - UG CUSTOMER	C	0	3,377,168	1,044	50,348	10,003
7	OH LINES DEMAND	D	0	10,568,667	3,266	157,560	31,305
8	UG LINES DEMAND	D	0	799,115	247	11,913	2,367
9	OH LINES CUSTOMER	C	0	11,874,743	3,670	177,032	35,174
10	UG LINES CUSTOMER	C	0	205,885	64	3,069	610
11	SERVICES - OH	C	280,305	2,135,471	591	28,628	6,174
12	SERVICES - UG	C	695,510	5,298,661	1,467	71,034	15,318
13	METER & METER INSTALLATIONS	C	68,977	5,171,731	8,326	182,539	78,724
14	INSTALL. ON CUSTR PREMISES	C	395,653	0	0	0	0
15	STREET LIGHTING	C	0	0	0	0	0
16	CUSTOMER ACCOUNTING	C	602	868,340	243	23,853	18,829
17	UNCOLLECTIBLES	C	0	0	0	0	0
18	CUSTOMER SERVICE	C	180	259,698	71	7,107	6,369
19	REVENUES	R	0	0	0	0	0
20			-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D	11,974,222	110,723,453	31,347	1,516,352	321,615
22	TOTAL CUSTOMER	C	1,441,226	34,274,991	17,047	619,392	186,258
23	TOTAL REVENUE	R	0	0	0	0	0
24			-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL		13,415,448	144,998,445	48,394	2,135,745	507,872
			===========	===========	===========	===========	===========

			C&I SC2 SEC GEN SERV (11)	C&I SC2 SEC SPACE HTG (12)	C&I SC2 PRIMARY GEN (13)	SC4 MUNI STR LTG (14)	SC6 DUSK TO DAWN (15)	SC6 ENERGY LTG (16)
	NET PLANT							
1	HIGH TENSION ≥ 69 KV	D	4,655,741	229,505	640,946	65,060	34,943	20,464
2	HIGH TENSION < 69 KV	D	40,589,445	2,000,860	5,587,865	567,202	304,640	178,408
3	TRANSFORMERS - OH DEMAND	D	2,857,495	144,397	0	33,991	18,264	11,144
4	TRANSFORMERS - UG DEMAND	D	1,523,337	76,978	0	18,121	9,737	5,941
5	TRANSFORMERS - OH CUSTOMER	C	2,242,897	113,340	0	26,680	14,336	8,748
6	TRANSFORMERS - UG CUSTOMER	C	1,490,105	75,299	0	17,725	9,524	5,812
7	OH LINES DEMAND	D	4,663,203	235,645	0	55,471	29,806	18,187
8	UG LINES DEMAND	D	352,593	17,817	0	4,194	2,254	1,375
9	OH LINES CUSTOMER	C	5,239,482	264,766	0	62,326	33,489	20,434
10	UG LINES CUSTOMER	C	90,843	4,591	0	1,081	581	354
11	SERVICES - OH	C	1,080,432	53,260	148,741	0	0	4,749
12	SERVICES - UG	C	2,680,835	132,152	369,065	0	0	11,783
13	METER & METER INSTALLATIONS	C	2,533,106	48,441	68,811	0	0	18,392
14	INSTALL. ON CUSTR PREMISES	C	0	0	0	0	0	0
15	STREET LIGHTING	C	0	0	0	1,854,605	996,522	0
16	CUSTOMER ACCOUNTING	C	100,764	2,289	1,072	292	7,607	1,420
17	UNCOLLECTIBLES	C	0	0	0	0	0	0
18	CUSTOMER SERVICE	C	28,578	704	340	109	2,843	440
19	REVENUES	R	0	0	0	0	0	0
20			-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D	54,641,813	2,705,202	6,228,811	744,039	399,643	235,519
22	TOTAL CUSTOMER	C	15,487,041	694,842	588,028	1,962,818	1,064,901	72,132
23	TOTAL REVENUE	R	0	0	0	0	0	0
24			-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL		70,128,854	3,400,044	6,816,839	2,706,857	1,464,545	307,651
			===========	===========	===========	===========	===========	===========

			SC7 PRIMARY T.O.U. (17)	SC7 SEP MET SP HTG (18)	SC7 HV TOD (19)
	NET PLANT				
1	HIGH TENSION ≥ 69 KV	D	1,126,675	81,199	235,915
2	HIGH TENSION < 69 KV	D	9,822,524	707,908	0
3	TRANSFORMERS - OH DEMAND	D	0	0	0
4	TRANSFORMERS - UG DEMAND	D	0	0	0
5	TRANSFORMERS - OH CUSTOMER	C	0	0	0
6	TRANSFORMERS - UG CUSTOMER	C	0	0	0
7	OH LINES DEMAND	D	0	0	0
8	UG LINES DEMAND	D	0	0	0
9	OH LINES CUSTOMER	C	0	0	0
10	UG LINES CUSTOMER	C	0	0	0
11	SERVICES - OH	C	261,461	18,843	0
12	SERVICES - UG	C	648,754	46,756	0
13	METER & METER INSTALLATIONS	C	38,588	18,233	12,156
14	INSTALL. ON CUSTR PREMISES	C	299,816	95,837	0
15	STREET LIGHTING	C	0	0	0
16	CUSTOMER ACCOUNTING	C	542	42	17
17	UNCOLLECTIBLES	C	0	0	0
18	CUSTOMER SERVICE	C	164	13	4
19	REVENUES	R	0	0	0
20			-------------------	-------------------	-------------------
21	TOTAL DEMAND	D	10,949,200	789,108	235,915
22	TOTAL CUSTOMER	C	1,249,325	179,724	12,177
23	TOTAL REVENUE	R	0	0	0
24			-------------------	-------------------	-------------------
25	TOTAL		12,198,524	968,832	248,091
			===========	===========	===========

				TOTAL COMPANY (1)	TOTAL RESIDENTIAL (2)	TOTAL C&I (3)	MUNICIPAL LIGHTING (4)	PRIVATE LIGHTING (5)
	RATE BASE ADJUSTMENTS							
1	HIGH TENSION ≥ 69 KV	D	D02	(3,939,274)	(2,234,441)	(1,330,128)	(15,585)	(13,272)
2	HIGH TENSION < 69 KV	D	D02A	(32,301,591)	(18,588,825)	(11,065,640)	(129,652)	(110,416)
3	TRANSFORMERS - OH DEMAND	D	D03	(2,350,044)	(1,599,607)	(735,012)	(8,270)	(7,155)
4	TRANSFORMERS - UG DEMAND	D	D03	(1,252,814)	(852,754)	(391,837)	(4,409)	(3,814)
5	TRANSFORMERS - OH CUSTOMER	C	C01	(1,844,590)	(1,255,559)	(576,924)	(6,491)	(5,616)
6	TRANSFORMERS - UG CUSTOMER	C	C01	(1,225,483)	(834,151)	(383,289)	(4,313)	(3,731)
7	OH LINES DEMAND	D	D03	(1,184,886)	(806,518)	(370,591)	(4,170)	(3,608)
8	UG LINES DEMAND	D	D03	(80,791)	(54,992)	(25,269)	(284)	(246)
9	OH LINES CUSTOMER	C	C01	(1,331,314)	(906,187)	(416,389)	(4,685)	(4,053)
10	UG LINES CUSTOMER	C	C01	(20,815)	(14,168)	(6,510)	(73)	(63)
11	SERVICES - OH	C	C02	(332,930)	(192,783)	(114,761)	0	(423)
12	SERVICES - UG	C	C02	(785,021)	(454,566)	(270,596)	0	(997)
13	METER & METER INSTALLATIONS	C	S01	(1,677,859)	(1,100,089)	(559,847)	0	(3,773)
14	INSTALL. ON CUSTR PREMISES	C	C03	(103,986)	0	0	0	0
15	STREET LIGHTING	C	C04	(883,109)	0	0	(574,446)	(308,663)
16	CUSTOMER ACCOUNTING	C	S02	(220,062)	(191,543)	(26,389)	(63)	(1,937)
17	UNCOLLECTIBLES	C	S03	0	0	0	0	0
18	CUSTOMER SERVICE	C	S04	(65,771)	(57,280)	(7,725)	(23)	(705)
19	REVENUES	R	R99	0	0	0	0	0
20				-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		(41,109,400)	(24,137,137)	(13,918,476)	(162,369)	(138,511)
22	TOTAL CUSTOMER	C		(8,490,941)	(5,006,327)	(2,362,429)	(590,094)	(329,962)
23	TOTAL REVENUE	R		0	0	0	0	0
24				-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL			(49,600,341)	(29,143,463)	(16,280,905)	(752,463)	(468,473)
				===========	===========	===========	===========	===========

				TOTAL PRIMARY (6)	RESID SC1 GENERAL (7)	RESID SC3 T.O.U. (8)	RESID SC5 W/ SP HTG (9)	C&I SC2 SEC NON DEM (10)
	RATE BASE ADJUSTMENTS							
1	HIGH TENSION ≥ 69 KV	D	D02	(345,848)	(2,204,280)	(610)	(29,551)	(6,373)
2	HIGH TENSION < 69 KV	D	D02A	(2,407,059)	(18,337,909)	(5,078)	(245,838)	(53,015)
3	TRANSFORMERS - OH DEMAND	D	D03	0	(1,575,630)	(487)	(23,490)	(4,667)
4	TRANSFORMERS - UG DEMAND	D	D03	0	(839,972)	(260)	(12,523)	(2,488)
5	TRANSFORMERS - OH CUSTOMER	C	C01	0	(1,236,739)	(382)	(18,438)	(3,663)
6	TRANSFORMERS - UG CUSTOMER	C	C01	0	(821,648)	(254)	(12,249)	(2,434)
7	OH LINES DEMAND	D	D03	0	(794,429)	(246)	(11,844)	(2,353)
8	UG LINES DEMAND	D	D03	0	(54,168)	(17)	(808)	(160)
9	OH LINES CUSTOMER	C	C01	0	(892,604)	(276)	(13,307)	(2,644)
10	UG LINES CUSTOMER	C	C01	0	(13,956)	(4)	(208)	(41)
11	SERVICES - OH	C	C02	(24,963)	(190,181)	(53)	(2,550)	(550)
12	SERVICES - UG	C	C02	(58,862)	(448,430)	(124)	(6,012)	(1,296)
13	METER & METER INSTALLATIONS	C	S01	(14,150)	(1,060,935)	(1,708)	(37,446)	(16,150)
14	INSTALL. ON CUSTR PREMISES	C	C03	(103,986)	0	0	0	0
15	STREET LIGHTING	C	C04	0	0	0	0	0
16	CUSTOMER ACCOUNTING	C	S02	(129)	(186,371)	(52)	(5,119)	(4,041)
17	UNCOLLECTIBLES	C	S03	0	0	0	0	0
18	CUSTOMER SERVICE	C	S04	(39)	(55,739)	(15)	(1,525)	(1,367)
19	REVENUES	R	R99	0	0	0	0	0
20				-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		(2,752,907)	(23,806,387)	(6,698)	(324,052)	(69,056)
22	TOTAL CUSTOMER	C		(202,129)	(4,906,603)	(2,869)	(96,855)	(32,186)
23	TOTAL REVENUE	R		0	0	0	0	0
24				-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL			(2,955,037)	(28,712,990)	(9,566)	(420,907)	(101,242)
				===========	===========	===========	===========	===========

				C&I SC2 SEC GEN SERV (11)	C&I SC2 SEC SPACE HTG (12)	C&I SC2 PRIMARY GEN (13)	SC4 MUNI STR LTG (14)	SC6 DUSK TO DAWN (15)	SC6 ENERGY LTG (16)
	RATE BASE ADJUSTMENTS								
1	HIGH TENSION ≥ 69 KV	D	D02	(1,115,246)	(54,976)	(153,534)	(15,585)	(8,370)	(4,902)
2	HIGH TENSION < 69 KV	D	D02A	(9,277,985)	(457,359)	(1,277,281)	(129,652)	(69,635)	(40,781)
3	TRANSFORMERS - OH DEMAND	D	D03	(695,214)	(35,131)	0	(8,270)	(4,444)	(2,711)
4	TRANSFORMERS - UG DEMAND	D	D03	(370,620)	(18,728)	0	(4,409)	(2,369)	(1,445)
5	TRANSFORMERS - OH CUSTOMER	C	C01	(545,685)	(27,575)	0	(6,491)	(3,488)	(2,128)
6	TRANSFORMERS - UG CUSTOMER	C	C01	(362,535)	(18,320)	0	(4,313)	(2,317)	(1,414)
7	OH LINES DEMAND	D	D03	(350,525)	(17,713)	0	(4,170)	(2,240)	(1,367)
8	UG LINES DEMAND	D	D03	(23,900)	(1,208)	0	(284)	(153)	(93)
9	OH LINES CUSTOMER	C	C01	(393,843)	(19,902)	0	(4,685)	(2,517)	(1,536)
10	UG LINES CUSTOMER	C	C01	(6,158)	(311)	0	(73)	(39)	(24)
11	SERVICES - OH	C	C02	(96,221)	(4,743)	(13,247)	0	0	(423)
12	SERVICES - UG	C	C02	(226,881)	(11,184)	(31,234)	0	0	(997)
13	METER & METER INSTALLATIONS	C	S01	(519,644)	(9,937)	(14,116)	0	0	(3,773)
14	INSTALL. ON CUSTR PREMISES	C	C03	0	0	0	0	0	0
15	STREET LIGHTING	C	C04	0	0	0	(574,446)	(308,663)	0
16	CUSTOMER ACCOUNTING	C	S02	(21,627)	(491)	(230)	(63)	(1,633)	(305)
17	UNCOLLECTIBLES	C	S03	0	0	0	0	0	0
18	CUSTOMER SERVICE	C	S04	(6,134)	(151)	(73)	(23)	(610)	(94)
19	REVENUES	R	R99	0	0	0	0	0	0
20				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		(11,833,490)	(585,115)	(1,430,815)	(162,369)	(87,211)	(51,300)
22	TOTAL CUSTOMER	C		(2,178,728)	(92,615)	(58,900)	(590,094)	(319,268)	(10,694)
23	TOTAL REVENUE	R		0	0	0	0	0	0
24				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL			(14,012,218)	(677,731)	(1,489,714)	(752,463)	(406,479)	(61,994)
				===========	===========	===========	===========	===========	===========

				SC7 PRIMARY T.O.U. (17)	SC7 SEP MET SP HTG (18)	SC7 HV TOD (19)
	RATE BASE ADJUSTMENTS					
1	HIGH TENSION ≥ 69 KV	D	D02	(269,886)	(19,451)	(56,511)
2	HIGH TENSION < 69 KV	D	D02A	(2,245,245)	(161,815)	0
3	TRANSFORMERS - OH DEMAND	D	D03	0	0	0
4	TRANSFORMERS - UG DEMAND	D	D03	0	0	0
5	TRANSFORMERS - OH CUSTOMER	C	C01	0	0	0
6	TRANSFORMERS - UG CUSTOMER	C	C01	0	0	0
7	OH LINES DEMAND	D	D03	0	0	0
8	UG LINES DEMAND	D	D03	0	0	0
9	OH LINES CUSTOMER	C	C01	0	0	0
10	UG LINES CUSTOMER	C	C01	0	0	0
11	SERVICES - OH	C	C02	(23,285)	(1,678)	0
12	SERVICES - UG	C	C02	(54,905)	(3,957)	0
13	METER & METER INSTALLATIONS	C	S01	(7,916)	(3,740)	(2,494)
14	INSTALL. ON CUSTR PREMISES	C	C03	(78,798)	(25,188)	0
15	STREET LIGHTING	C	C04	0	0	0
16	CUSTOMER ACCOUNTING	C	S02	(116)	(9)	(4)
17	UNCOLLECTIBLES	C	S03	0	0	0
18	CUSTOMER SERVICE	C	S04	(35)	(3)	(1)
19	REVENUES	R	R99	0	0	0
20				-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		(2,515,131)	(181,265)	(56,511)
22	TOTAL CUSTOMER	C		(165,056)	(34,575)	(2,498)
23	TOTAL REVENUE	R		0	0	0
24				-------------------	-------------------	-------------------
25	TOTAL			(2,680,186)	(215,841)	(59,010)
				===========	===========	===========

				TOTAL COMPANY (1)	TOTAL RESIDENTIAL (2)	TOTAL C&I (3)	MUNICIPAL LIGHTING (4)	PRIVATE LIGHTING (5)
	WORKING CAPITAL							
1	HIGH TENSION ≥ 69 KV	D	D02	432,110	245,102	145,905	1,710	1,456
2	HIGH TENSION < 69 KV	D	D02A	3,680,626	2,118,116	1,260,881	14,773	12,581
3	TRANSFORMERS - OH DEMAND	D	D03	202,218	137,644	63,247	712	616
4	TRANSFORMERS - UG DEMAND	D	D03	107,803	73,378	33,717	379	328
5	TRANSFORMERS - OH CUSTOMER	C	C01	158,724	108,039	49,643	559	483
6	TRANSFORMERS - UG CUSTOMER	C	C01	105,451	71,778	32,981	371	321
7	OH LINES DEMAND	D	D03	571,169	388,778	178,642	2,010	1,739
8	UG LINES DEMAND	D	D03	26,003	17,699	8,133	92	79
9	OH LINES CUSTOMER	C	C01	641,754	436,824	200,718	2,258	1,954
10	UG LINES CUSTOMER	C	C01	6,699	4,560	2,095	24	20
11	SERVICES - OH	C	C02	163,532	94,693	56,369	0	208
12	SERVICES - UG	C	C02	230,941	133,726	79,605	0	293
13	METER & METER INSTALLATIONS	C	S01	178,590	117,092	59,590	0	402
14	INSTALL. ON CUSTR PREMISES	C	C03	8,965	0	0	0	0
15	STREET LIGHTING	C	C04	103,404	0	0	67,262	36,142
16	CUSTOMER ACCOUNTING	C	S02	533,778	464,604	64,010	152	4,699
17	UNCOLLECTIBLES	C	S03	41,318	22,913	15,063	556	302
18	CUSTOMER SERVICE	C	S04	133,768	116,498	15,711	48	1,433
19	REVENUES	R	R99	0	0	0	0	0
20				-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		5,019,928	2,980,717	1,690,525	19,675	16,799
22	TOTAL CUSTOMER	C		2,306,925	1,570,727	575,786	71,230	46,256
23	TOTAL REVENUE	R		0	0	0	0	0
24				-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL			7,326,853	4,551,444	2,266,311	90,905	63,056
				===========	===========	===========	===========	===========

				TOTAL PRIMARY (6)	RESID SC1 GENERAL (7)	RESID SC3 T.O.U. (8)	RESID SC5 W/ SP HTG (9)	C&I SC2 SEC NON DEM (10)
	WORKING CAPITAL							
1	HIGH TENSION ≥ 69 KV	D	D02	37,937	241,794	67	3,241	699
2	HIGH TENSION < 69 KV	D	D02A	274,274	2,089,525	579	28,012	6,041
3	TRANSFORMERS - OH DEMAND	D	D03	0	135,581	42	2,021	402
4	TRANSFORMERS - UG DEMAND	D	D03	0	72,278	22	1,078	214
5	TRANSFORMERS - OH CUSTOMER	C	C01	0	106,420	33	1,587	315
6	TRANSFORMERS - UG CUSTOMER	C	C01	0	70,702	22	1,054	209
7	OH LINES DEMAND	D	D03	0	382,951	118	5,709	1,134
8	UG LINES DEMAND	D	D03	0	17,434	5	260	52
9	OH LINES CUSTOMER	C	C01	0	430,276	133	6,415	1,275
10	UG LINES CUSTOMER	C	C01	0	4,492	1	67	13
11	SERVICES - OH	C	C02	12,262	93,415	26	1,252	270
12	SERVICES - UG	C	C02	17,316	131,921	37	1,769	381
13	METER & METER INSTALLATIONS	C	S01	1,506	112,925	182	3,986	1,719
14	INSTALL. ON CUSTR PREMISES	C	C03	8,965	0	0	0	0
15	STREET LIGHTING	C	C04	0	0	0	0	0
16	CUSTOMER ACCOUNTING	C	S02	313	452,060	127	12,418	9,802
17	UNCOLLECTIBLES	C	S03	2,485	22,432	6	474	227
18	CUSTOMER SERVICE	C	S04	79	113,365	31	3,102	2,780
19	REVENUES	R	R99	0	0	0	0	0
20				-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		312,211	2,939,562	834	40,322	8,541
22	TOTAL CUSTOMER	C		42,926	1,538,007	597	32,123	16,992
23	TOTAL REVENUE	R		0	0	0	0	0
24				-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL			355,137	4,477,569	1,431	72,444	25,533
				===========	===========	===========	===========	===========

				C&I SC2 SEC GEN SERV (11)	C&I SC2 SEC SPACE HTG (12)	C&I SC2 PRIMARY GEN (13)	SC4 MUNI STR LTG (14)	SC6 DUSK TO DAWN (15)	SC6 ENERGY LTG (16)
	WORKING CAPITAL								
1	HIGH TENSION ≥ 69 KV	D	D02	122,334	6,030	16,842	1,710	918	538
2	HIGH TENSION < 69 KV	D	D02A	1,057,186	52,114	145,541	14,773	7,935	4,647
3	TRANSFORMERS - OH DEMAND	D	D03	59,822	3,023	0	712	382	233
4	TRANSFORMERS - UG DEMAND	D	D03	31,891	1,612	0	379	204	124
5	TRANSFORMERS - OH CUSTOMER	C	C01	46,955	2,373	0	559	300	183
6	TRANSFORMERS - UG CUSTOMER	C	C01	31,196	1,576	0	371	199	122
7	OH LINES DEMAND	D	D03	168,969	8,538	0	2,010	1,080	659
8	UG LINES DEMAND	D	D03	7,692	389	0	92	49	30
9	OH LINES CUSTOMER	C	C01	189,850	9,594	0	2,258	1,213	740
10	UG LINES CUSTOMER	C	C01	1,982	100	0	24	13	8
11	SERVICES - OH	C	C02	47,263	2,330	6,507	0	0	208
12	SERVICES - UG	C	C02	66,745	3,290	9,189	0	0	293
13	METER & METER INSTALLATIONS	C	S01	55,310	1,058	1,502	0	0	402
14	INSTALL. ON CUSTR PREMISES	C	C03	0	0	0	0	0	0
15	STREET LIGHTING	C	C04	0	0	0	67,262	36,142	0
16	CUSTOMER ACCOUNTING	C	S02	52,458	1,192	558	152	3,960	739
17	UNCOLLECTIBLES	C	S03	12,697	529	1,610	556	238	63
18	CUSTOMER SERVICE	C	S04	12,475	307	148	48	1,241	192
19	REVENUES	R	R99	0	0	0	0	0	0
20				------------------	------------------	------------------	------------------	------------------	------------------
21	TOTAL DEMAND	D		1,447,895	71,706	162,382	19,675	10,568	6,231
22	TOTAL CUSTOMER	C		516,932	22,349	19,514	71,230	43,306	2,950
23	TOTAL REVENUE	R		0	0	0	0	0	0
24				------------------	------------------	------------------	------------------	------------------	------------------
25	TOTAL			1,964,827	94,055	181,896	90,905	53,874	9,181
				===========	===========	===========	===========	===========	===========

				SC7 PRIMARY T.O.U. (17)	SC7 SEP MET SP HTG (18)	SC7 HV TOD (19)
	WORKING CAPITAL					
1	HIGH TENSION ≥ 69 KV	D	D02	29,605	2,134	6,199
2	HIGH TENSION < 69 KV	D	D02A	255,836	18,438	0
3	TRANSFORMERS - OH DEMAND	D	D03	0	0	0
4	TRANSFORMERS - UG DEMAND	D	D03	0	0	0
5	TRANSFORMERS - OH CUSTOMER	C	C01	0	0	0
6	TRANSFORMERS - UG CUSTOMER	C	C01	0	0	0
7	OH LINES DEMAND	D	D03	0	0	0
8	UG LINES DEMAND	D	D03	0	0	0
9	OH LINES CUSTOMER	C	C01	0	0	0
10	UG LINES CUSTOMER	C	C01	0	0	0
11	SERVICES - OH	C	C02	11,437	824	0
12	SERVICES - UG	C	C02	16,152	1,164	0
13	METER & METER INSTALLATIONS	C	S01	843	398	265
14	INSTALL. ON CUSTR PREMISES	C	C03	6,793	2,172	0
15	STREET LIGHTING	C	C04	0	0	0
16	CUSTOMER ACCOUNTING	C	S02	282	22	9
17	UNCOLLECTIBLES	C	S03	2,256	121	108
18	CUSTOMER SERVICE	C	S04	71	5	2
19	REVENUES	R	R99	0	0	0
20				-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		285,440	20,572	6,199
22	TOTAL CUSTOMER	C		37,835	4,706	384
23	TOTAL REVENUE	R		0	0	0
24				-------------------	-------------------	-------------------
25	TOTAL			323,276	25,278	6,583
				===========	===========	===========

			TOTAL COMPANY (1)	TOTAL RESIDENTIAL (2)	TOTAL C&I (3)	MUNICIPAL LIGHTING (4)	PRIVATE LIGHTING (5)
	TOTAL RATE BASE						
1	HIGH TENSION ≥ 69 KV	D	12,937,856	7,338,630	4,368,573	51,185	43,591
2	HIGH TENSION < 69 KV	D	112,692,441	64,851,916	38,605,341	452,324	385,213
3	TRANSFORMERS - OH DEMAND	D	7,511,415	5,112,803	2,349,310	26,433	22,869
4	TRANSFORMERS - UG DEMAND	D	4,004,353	2,725,647	1,252,422	14,091	12,192
5	TRANSFORMERS - OH CUSTOMER	C	5,895,840	4,013,128	1,844,014	20,748	17,951
6	TRANSFORMERS - UG CUSTOMER	C	3,916,996	2,666,186	1,225,100	13,784	11,926
7	OH LINES DEMAND	D	15,149,393	10,311,754	4,738,203	53,311	46,124
8	UG LINES DEMAND	D	1,137,087	773,982	355,641	4,001	3,462
9	OH LINES CUSTOMER	C	17,021,555	11,586,081	5,323,751	59,899	51,824
10	UG LINES CUSTOMER	C	292,961	199,410	91,628	1,031	892
11	SERVICES - OH	C	3,568,952	2,066,600	1,230,215	0	4,534
12	SERVICES - UG	C	8,721,745	5,050,323	3,006,379	0	11,080
13	METER & METER INSTALLATIONS	C	6,679,778	4,379,599	2,228,825	0	15,020
14	INSTALL. ON CUSTR PREMISES	C	300,631	0	0	0	0
15	STREET LIGHTING	C	2,071,421	0	0	1,347,421	724,000
16	CUSTOMER ACCOUNTING	C	1,339,025	1,165,497	160,574	381	11,788
17	UNCOLLECTIBLES	C	41,318	22,913	15,063	556	302
18	CUSTOMER SERVICE	C	374,437	326,095	43,977	133	4,011
19	REVENUES	R	0	0	0	0	0
20			-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D	153,432,546	91,114,733	51,669,491	601,345	513,451
22	TOTAL CUSTOMER	C	50,224,660	31,475,832	15,169,525	1,443,953	853,327
23	TOTAL REVENUE	R	0	0	0	0	0
24			-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL		203,657,206	122,590,564	66,839,016	2,045,299	1,366,779
			===========	===========	===========	===========	===========

			TOTAL PRIMARY (6)	RESID SC1 GENERAL (7)	RESID SC3 T.O.U. (8)	RESID SC5 W/ SP HTG (9)	C&I SC2 SEC NON DEM (10)
	TOTAL RATE BASE						
1	HIGH TENSION ≥ 69 KV	D	1,135,878	7,239,571	2,005	97,054	20,930
2	HIGH TENSION < 69 KV	D	8,397,648	63,976,529	17,717	857,670	184,956
3	TRANSFORMERS - OH DEMAND	D	0	5,036,167	1,556	75,080	14,917
4	TRANSFORMERS - UG DEMAND	D	0	2,684,792	830	40,026	7,953
5	TRANSFORMERS - OH CUSTOMER	C	0	3,952,974	1,222	58,932	11,709
6	TRANSFORMERS - UG CUSTOMER	C	0	2,626,222	812	39,152	7,779
7	OH LINES DEMAND	D	0	10,157,189	3,139	151,426	30,086
8	UG LINES DEMAND	D	0	762,381	236	11,366	2,258
9	OH LINES CUSTOMER	C	0	11,412,415	3,527	170,139	33,804
10	UG LINES CUSTOMER	C	0	196,421	61	2,928	582
11	SERVICES - OH	C	267,603	2,038,705	565	27,331	5,894
12	SERVICES - UG	C	653,964	4,982,152	1,380	66,791	14,403
13	METER & METER INSTALLATIONS	C	56,333	4,223,721	6,800	149,079	64,293
14	INSTALL. ON CUSTR PREMISES	C	300,631	0	0	0	0
15	STREET LIGHTING	C	0	0	0	0	0
16	CUSTOMER ACCOUNTING	C	786	1,134,028	317	31,151	24,590
17	UNCOLLECTIBLES	C	2,485	22,432	6	474	227
18	CUSTOMER SERVICE	C	220	317,324	87	8,684	7,782
19	REVENUES	R	0	0	0	0	0
20			-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D	9,533,526	89,856,629	25,483	1,232,621	261,100
22	TOTAL CUSTOMER	C	1,282,023	30,906,395	14,776	554,661	171,063
23	TOTAL REVENUE	R	0	0	0	0	0
24			-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL		10,815,548	120,763,024	40,259	1,787,282	432,163
			===========	===========	===========	===========	===========

			C&I SC2 SEC GEN SERV (11)	C&I SC2 SEC SPACE HTG (12)	C&I SC2 PRIMARY GEN (13)	SC4 MUNI STR LTG (14)	SC6 DUSK TO DAWN (15)	SC6 ENERGY LTG (16)
	TOTAL RATE BASE							
1	HIGH TENSION ≥ 69 KV	D	3,662,829	180,559	504,254	51,185	27,491	16,100
2	HIGH TENSION < 69 KV	D	32,368,646	1,595,615	4,456,125	452,324	242,939	142,274
3	TRANSFORMERS - OH DEMAND	D	2,222,103	112,289	0	26,433	14,203	8,666
4	TRANSFORMERS - UG DEMAND	D	1,184,608	59,862	0	14,091	7,572	4,620
5	TRANSFORMERS - OH CUSTOMER	C	1,744,167	88,138	0	20,748	11,148	6,802
6	TRANSFORMERS - UG CUSTOMER	C	1,158,766	58,556	0	13,784	7,406	4,519
7	OH LINES DEMAND	D	4,481,647	226,470	0	53,311	28,645	17,479
8	UG LINES DEMAND	D	336,385	16,998	0	4,001	2,150	1,312
9	OH LINES CUSTOMER	C	5,035,489	254,457	0	59,899	32,185	19,639
10	UG LINES CUSTOMER	C	86,667	4,380	0	1,031	554	338
11	SERVICES - OH	C	1,031,474	50,847	142,001	0	0	4,534
12	SERVICES - UG	C	2,520,698	124,258	347,019	0	0	11,080
13	METER & METER INSTALLATIONS	C	2,068,772	39,562	56,197	0	0	15,020
14	INSTALL. ON CUSTR PREMISES	C	0	0	0	0	0	0
15	STREET LIGHTING	C	0	0	0	1,347,421	724,000	0
16	CUSTOMER ACCOUNTING	C	131,595	2,990	1,400	381	9,934	1,854
17	UNCOLLECTIBLES	C	12,697	529	1,610	556	238	63
18	CUSTOMER SERVICE	C	34,920	861	415	133	3,474	538
19	REVENUES	R	0	0	0	0	0	0
20			-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D	44,256,218	2,191,793	4,960,379	601,345	323,000	190,451
22	TOTAL CUSTOMER	C	13,825,244	624,576	548,642	1,443,953	788,940	64,387
23	TOTAL REVENUE	R	0	0	0	0	0	0
24			-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL		58,081,463	2,816,369	5,509,021	2,045,299	1,111,940	254,838
			===========	===========	===========	===========	===========	===========

			SC7 PRIMARY T.O.U. (17)	SC7 SEP MET SP HTG (18)	SC7 HV TOD (19)
	TOTAL RATE BASE				
1	HIGH TENSION ≥ 69 KV	D	886,394	63,882	185,602
2	HIGH TENSION < 69 KV	D	7,833,116	564,532	0
3	TRANSFORMERS - OH DEMAND	D	0	0	0
4	TRANSFORMERS - UG DEMAND	D	0	0	0
5	TRANSFORMERS - OH CUSTOMER	C	0	0	0
6	TRANSFORMERS - UG CUSTOMER	C	0	0	0
7	OH LINES DEMAND	D	0	0	0
8	UG LINES DEMAND	D	0	0	0
9	OH LINES CUSTOMER	C	0	0	0
10	UG LINES CUSTOMER	C	0	0	0
11	SERVICES - OH	C	249,614	17,990	0
12	SERVICES - UG	C	610,001	43,963	0
13	METER & METER INSTALLATIONS	C	31,514	14,891	9,927
14	INSTALL. ON CUSTR PREMISES	C	227,811	72,820	0
15	STREET LIGHTING	C	0	0	0
16	CUSTOMER ACCOUNTING	C	708	55	22
17	UNCOLLECTIBLES	C	2,256	121	108
18	CUSTOMER SERVICE	C	200	15	5
19	REVENUES	R	0	0	0
20			-------------------	-------------------	-------------------
21	TOTAL DEMAND	D	8,719,509	628,414	185,602
22	TOTAL CUSTOMER	C	1,122,104	149,855	10,063
23	TOTAL REVENUE	R	0	0	0
24			-------------------	-------------------	-------------------
25	TOTAL		9,841,614	778,269	195,665
			===========	===========	===========

				TOTAL COMPANY (1)	TOTAL RESIDENTIAL (2)	TOTAL C&I (3)	MUNICIPAL LIGHTING (4)	PRIVATE LIGHTING (5)
	OPERATION & MAINTENANCE							
1	HIGH TENSION ≥ 69 KV	D	D02	2,348,034	1,331,855	792,833	9,289	7,911
2	HIGH TENSION < 69 KV	D	D02A	20,638,506	11,876,987	7,070,186	82,839	70,548
3	TRANSFORMERS - OH DEMAND	D	D03	620,355	422,257	194,025	2,183	1,889
4	TRANSFORMERS - UG DEMAND	D	D03	330,713	225,106	103,435	1,164	1,007
5	TRANSFORMERS - OH CUSTOMER	C	C01	486,927	331,437	152,294	1,714	1,483
6	TRANSFORMERS - UG CUSTOMER	C	C01	323,498	220,196	101,179	1,138	985
7	OH LINES DEMAND	D	D03	4,729,846	3,219,470	1,479,332	16,645	14,401
8	UG LINES DEMAND	D	D03	88,939	60,538	27,817	313	271
9	OH LINES CUSTOMER	C	C01	5,314,361	3,617,332	1,662,147	18,701	16,180
10	UG LINES CUSTOMER	C	C01	22,914	15,597	7,167	81	70
11	SERVICES - OH	C	C02	1,377,796	797,812	474,925	0	1,750
12	SERVICES - UG	C	C02	763,180	441,919	263,067	0	969
13	METER & METER INSTALLATIONS	C	S01	843,375	552,959	281,407	0	1,896
14	INSTALL. ON CUSTR PREMISES	C	C03	26,366	0	0	0	0
15	STREET LIGHTING	C	C04	701,417	0	0	456,258	245,158
16	CUSTOMER ACCOUNTING	C	S02	7,808,695	6,796,742	936,406	2,222	68,743
17	UNCOLLECTIBLES	C	S03	611,945	339,347	223,087	8,240	4,466
18	CUSTOMER SERVICE	C	S04	1,955,308	1,702,865	229,649	696	20,948
19	REVENUES	R	R99	0	0	0	0	0
20				-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		28,756,393	17,136,214	9,667,629	112,432	96,026
22	TOTAL CUSTOMER	C		20,235,781	14,816,206	4,331,329	489,050	362,648
23	TOTAL REVENUE	R		0	0	0	0	0
24				-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL			48,992,174	31,952,421	13,998,957	601,482	458,674
				===========	===========	===========	===========	===========

				TOTAL PRIMARY (6)	RESID SC1 GENERAL (7)	RESID SC3 T.O.U. (8)	RESID SC5 W/ SP HTG (9)	C&I SC2 SEC NON DEM (10)
	OPERATION & MAINTENANCE							
1	HIGH TENSION ≥ 69 KV	D	D02	206,145	1,313,878	364	17,614	3,798
2	HIGH TENSION < 69 KV	D	D02A	1,537,946	11,716,669	3,245	157,074	33,873
3	TRANSFORMERS - OH DEMAND	D	D03	0	415,928	129	6,201	1,232
4	TRANSFORMERS - UG DEMAND	D	D03	0	221,732	69	3,306	657
5	TRANSFORMERS - OH CUSTOMER	C	C01	0	326,469	101	4,867	967
6	TRANSFORMERS - UG CUSTOMER	C	C01	0	216,895	67	3,234	642
7	OH LINES DEMAND	D	D03	0	3,171,213	980	47,277	9,393
8	UG LINES DEMAND	D	D03	0	59,631	18	889	177
9	OH LINES CUSTOMER	C	C01	0	3,563,111	1,101	53,120	10,554
10	UG LINES CUSTOMER	C	C01	0	15,363	5	229	46
11	SERVICES - OH	C	C02	103,308	787,043	218	10,551	2,275
12	SERVICES - UG	C	C02	57,224	435,954	121	5,844	1,260
13	METER & METER INSTALLATIONS	C	S01	7,113	533,278	859	18,822	8,118
14	INSTALL. ON CUSTR PREMISES	C	C03	26,366	0	0	0	0
15	STREET LIGHTING	C	C04	0	0	0	0	0
16	CUSTOMER ACCOUNTING	C	S02	4,583	6,613,231	1,851	181,660	143,397
17	UNCOLLECTIBLES	C	S03	36,805	332,233	96	7,018	3,355
18	CUSTOMER SERVICE	C	S04	1,150	1,657,063	455	45,347	40,638
19	REVENUES	R	R99	0	0	0	0	0
20				-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		1,744,092	16,899,050	4,804	232,360	49,130
22	TOTAL CUSTOMER	C		236,548	14,480,641	4,873	330,692	211,253
23	TOTAL REVENUE	R		0	0	0	0	0
24				-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL			1,980,640	31,379,691	9,677	563,052	260,383
				===========	===========	===========	===========	===========

				C&I SC2 SEC GEN SERV (11)	C&I SC2 SEC SPACE HTG (12)	C&I SC2 PRIMARY GEN (13)	SC4 MUNI STR LTG (14)	SC6 DUSK TO DAWN (15)	SC6 ENERGY LTG (16)
	OPERATION & MAINTENANCE								
1	HIGH TENSION ≥ 69 KV	D	D02	664,751	32,769	91,515	9,289	4,989	2,922
2	HIGH TENSION < 69 KV	D	D02A	5,927,997	292,221	816,095	82,839	44,492	26,056
3	TRANSFORMERS - OH DEMAND	D	D03	183,520	9,274	0	2,183	1,173	716
4	TRANSFORMERS - UG DEMAND	D	D03	97,835	4,944	0	1,164	625	382
5	TRANSFORMERS - OH CUSTOMER	C	C01	144,048	7,279	0	1,714	921	562
6	TRANSFORMERS - UG CUSTOMER	C	C01	95,700	4,836	0	1,138	612	373
7	OH LINES DEMAND	D	D03	1,399,231	70,707	0	16,645	8,943	5,457
8	UG LINES DEMAND	D	D03	26,311	1,330	0	313	168	103
9	OH LINES CUSTOMER	C	C01	1,572,148	79,445	0	18,701	10,049	6,132
10	UG LINES CUSTOMER	C	C01	6,779	343	0	81	43	26
11	SERVICES - OH	C	C02	398,201	19,629	54,820	0	0	1,750
12	SERVICES - UG	C	C02	220,569	10,873	30,365	0	0	969
13	METER & METER INSTALLATIONS	C	S01	261,199	4,995	7,095	0	0	1,896
14	INSTALL. ON CUSTR PREMISES	C	C03	0	0	0	0	0	0
15	STREET LIGHTING	C	C04	0	0	0	456,258	245,158	0
16	CUSTOMER ACCOUNTING	C	S02	767,411	17,435	8,162	2,222	57,932	10,811
17	UNCOLLECTIBLES	C	S03	188,055	7,834	23,843	8,240	3,528	938
18	CUSTOMER SERVICE	C	S04	182,349	4,495	2,167	696	18,139	2,809
19	REVENUES	R	R99	0	0	0	0	0	0
20				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		8,299,644	411,244	907,610	112,432	60,391	35,635
22	TOTAL CUSTOMER	C		3,836,460	157,164	126,452	489,050	336,381	26,268
23	TOTAL REVENUE	R		0	0	0	0	0	0
24				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL			12,136,104	568,408	1,034,062	601,482	396,772	61,903
				===========	===========	===========	===========	===========	===========

				SC7 PRIMARY T.O.U. (17)	SC7 SEP MET SP HTG (18)	SC7 HV TOD (19)
	OPERATION & MAINTENANCE					
1	HIGH TENSION ≥ 69 KV	D	D02	160,868	11,594	33,684
2	HIGH TENSION < 69 KV	D	D02A	1,434,558	103,388	0
3	TRANSFORMERS - OH DEMAND	D	D03	0	0	0
4	TRANSFORMERS - UG DEMAND	D	D03	0	0	0
5	TRANSFORMERS - OH CUSTOMER	C	C01	0	0	0
6	TRANSFORMERS - UG CUSTOMER	C	C01	0	0	0
7	OH LINES DEMAND	D	D03	0	0	0
8	UG LINES DEMAND	D	D03	0	0	0
9	OH LINES CUSTOMER	C	C01	0	0	0
10	UG LINES CUSTOMER	C	C01	0	0	0
11	SERVICES - OH	C	C02	96,363	6,945	0
12	SERVICES - UG	C	C02	53,377	3,847	0
13	METER & METER INSTALLATIONS	C	S01	3,979	1,880	1,253
14	INSTALL. ON CUSTR PREMISES	C	C03	19,979	6,386	0
15	STREET LIGHTING	C	C04	0	0	0
16	CUSTOMER ACCOUNTING	C	S02	4,130	323	130
17	UNCOLLECTIBLES	C	S03	33,415	1,786	1,604
18	CUSTOMER SERVICE	C	S04	1,043	80	27
19	REVENUES	R	R99	0	0	0
20				-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		1,595,425	114,982	33,684
22	TOTAL CUSTOMER	C		212,287	21,248	3,014
23	TOTAL REVENUE	R		0	0	0
24				-------------------	-------------------	-------------------
25	TOTAL			1,807,712	136,230	36,698
				===========	===========	===========

				TOTAL COMPANY (1)	TOTAL RESIDENTIAL (2)	TOTAL C&I (3)	MUNICIPAL LIGHTING (4)	PRIVATE LIGHTING (5)
	DEPRECIATION & AMORTIZATION							
1	HIGH TENSION ≥ 69 KV	D	D02	37,319	21,168	12,601	148	126
2	HIGH TENSION < 69 KV	D	D02A	351,636	202,358	120,461	1,411	1,202
3	TRANSFORMERS - OH DEMAND	D	D03	30,349	20,658	9,492	107	92
4	TRANSFORMERS - UG DEMAND	D	D03	16,179	11,013	5,060	57	49
5	TRANSFORMERS - OH CUSTOMER	C	C01	23,822	16,215	7,451	84	73
6	TRANSFORMERS - UG CUSTOMER	C	C01	15,826	10,773	4,950	56	48
7	OH LINES DEMAND	D	D03	41,343	28,141	12,931	145	126
8	UG LINES DEMAND	D	D03	2,506	1,706	784	9	8
9	OH LINES CUSTOMER	C	C01	46,453	31,619	14,529	163	141
10	UG LINES CUSTOMER	C	C01	646	439	202	2	2
11	SERVICES - OH	C	C02	11,290	6,538	3,892	0	14
12	SERVICES - UG	C	C02	25,413	14,715	8,760	0	32
13	METER & METER INSTALLATIONS	C	S01	49,260	32,297	16,436	0	111
14	INSTALL. ON CUSTR PREMISES	C	C03	1,555	0	0	0	0
15	STREET LIGHTING	C	C04	13,063	0	0	8,497	4,566
16	CUSTOMER ACCOUNTING	C	S02	11,254	9,796	1,350	3	99
17	UNCOLLECTIBLES	C	S03	0	0	0	0	0
18	CUSTOMER SERVICE	C	S04	3,364	2,929	395	1	36
19	REVENUES	R	R99	0	0	0	0	0
20				-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		479,333	285,044	161,329	1,877	1,603
22	TOTAL CUSTOMER	C		201,945	125,321	57,964	8,807	5,122
23	TOTAL REVENUE	R		0	0	0	0	0
24				-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL			681,279	410,366	219,293	10,684	6,725
				===========	===========	===========	===========	===========

				TOTAL PRIMARY (6)	RESID SC1 GENERAL (7)	RESID SC3 T.O.U. (8)	RESID SC5 W/ SP HTG (9)	C&I SC2 SEC NON DEM (10)
	DEPRECIATION & AMORTIZATION							
1	HIGH TENSION ≥ 69 KV	D	D02	3,276	20,883	6	280	60
2	HIGH TENSION < 69 KV	D	D02A	26,203	199,627	55	2,676	577
3	TRANSFORMERS - OH DEMAND	D	D03	0	20,348	6	303	60
4	TRANSFORMERS - UG DEMAND	D	D03	0	10,848	3	162	32
5	TRANSFORMERS - OH CUSTOMER	C	C01	0	15,972	5	238	47
6	TRANSFORMERS - UG CUSTOMER	C	C01	0	10,611	3	158	31
7	OH LINES DEMAND	D	D03	0	27,719	9	413	82
8	UG LINES DEMAND	D	D03	0	1,680	1	25	5
9	OH LINES CUSTOMER	C	C01	0	31,145	10	464	92
10	UG LINES CUSTOMER	C	C01	0	433	0	6	1
11	SERVICES - OH	C	C02	847	6,449	2	86	19
12	SERVICES - UG	C	C02	1,905	14,516	4	195	42
13	METER & METER INSTALLATIONS	C	S01	415	31,148	50	1,099	474
14	INSTALL. ON CUSTR PREMISES	C	C03	1,555	0	0	0	0
15	STREET LIGHTING	C	C04	0	0	0	0	0
16	CUSTOMER ACCOUNTING	C	S02	7	9,531	3	262	207
17	UNCOLLECTIBLES	C	S03	0	0	0	0	0
18	CUSTOMER SERVICE	C	S04	2	2,851	1	78	70
19	REVENUES	R	R99	0	0	0	0	0
20				-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		29,480	281,105	80	3,860	817
22	TOTAL CUSTOMER	C		4,731	122,657	77	2,587	984
23	TOTAL REVENUE	R		0	0	0	0	0
24				-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL			34,211	403,762	157	6,447	1,801
				===========	===========	===========	===========	===========

				C&I SC2 SEC GEN SERV (11)	C&I SC2 SEC SPACE HTG (12)	C&I SC2 PRIMARY GEN (13)	SC4 MUNI STR LTG (14)	SC6 DUSK TO DAWN (15)	SC6 ENERGY LTG (16)
	DEPRECIATION & AMORTIZATION								
1	HIGH TENSION ≥ 69 KV	D	D02	10,565	521	1,455	148	79	46
2	HIGH TENSION < 69 KV	D	D02A	101,000	4,979	13,905	1,411	758	444
3	TRANSFORMERS - OH DEMAND	D	D03	8,978	454	0	107	57	35
4	TRANSFORMERS - UG DEMAND	D	D03	4,786	242	0	57	31	19
5	TRANSFORMERS - OH CUSTOMER	C	C01	7,047	356	0	84	45	27
6	TRANSFORMERS - UG CUSTOMER	C	C01	4,682	237	0	56	30	18
7	OH LINES DEMAND	D	D03	12,231	618	0	145	78	48
8	UG LINES DEMAND	D	D03	741	37	0	9	5	3
9	OH LINES CUSTOMER	C	C01	13,742	694	0	163	88	54
10	UG LINES CUSTOMER	C	C01	191	10	0	2	1	1
11	SERVICES - OH	C	C02	3,263	161	449	0	0	14
12	SERVICES - UG	C	C02	7,345	362	1,011	0	0	32
13	METER & METER INSTALLATIONS	C	S01	15,256	292	414	0	0	111
14	INSTALL. ON CUSTR PREMISES	C	C03	0	0	0	0	0	0
15	STREET LIGHTING	C	C04	0	0	0	8,497	4,566	0
16	CUSTOMER ACCOUNTING	C	S02	1,106	25	12	3	83	16
17	UNCOLLECTIBLES	C	S03	0	0	0	0	0	0
18	CUSTOMER SERVICE	C	S04	314	8	4	1	31	5
19	REVENUES	R	R99	0	0	0	0	0	0
20				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		138,302	6,851	15,359	1,877	1,008	595
22	TOTAL CUSTOMER	C		52,946	2,144	1,890	8,807	4,844	278
23	TOTAL REVENUE	R		0	0	0	0	0	0
24				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL			191,248	8,995	17,249	10,684	5,853	873
				===========	===========	===========	===========	===========	===========

				SC7 PRIMARY T.O.U. (17)	SC7 SEP MET SP HTG (18)	SC7 HV TOD (19)
	DEPRECIATION & AMORTIZATION					
1	HIGH TENSION ≥ 69 KV	D	D02	2,557	184	535
2	HIGH TENSION < 69 KV	D	D02A	24,442	1,762	0
3	TRANSFORMERS - OH DEMAND	D	D03	0	0	0
4	TRANSFORMERS - UG DEMAND	D	D03	0	0	0
5	TRANSFORMERS - OH CUSTOMER	C	C01	0	0	0
6	TRANSFORMERS - UG CUSTOMER	C	C01	0	0	0
7	OH LINES DEMAND	D	D03	0	0	0
8	UG LINES DEMAND	D	D03	0	0	0
9	OH LINES CUSTOMER	C	C01	0	0	0
10	UG LINES CUSTOMER	C	C01	0	0	0
11	SERVICES - OH	C	C02	790	57	0
12	SERVICES - UG	C	C02	1,777	128	0
13	METER & METER INSTALLATIONS	C	S01	232	110	73
14	INSTALL. ON CUSTR PREMISES	C	C03	1,179	377	0
15	STREET LIGHTING	C	C04	0	0	0
16	CUSTOMER ACCOUNTING	C	S02	6	0	0
17	UNCOLLECTIBLES	C	S03	0	0	0
18	CUSTOMER SERVICE	C	S04	2	0	0
19	REVENUES	R	R99	0	0	0
20				-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		26,999	1,946	535
22	TOTAL CUSTOMER	C		3,986	672	73
23	TOTAL REVENUE	R		0	0	0
24				-------------------	-------------------	-------------------
25	TOTAL			30,984	2,618	609
				===========	===========	===========

				TOTAL COMPANY (1)	TOTAL RESIDENTIAL (2)	TOTAL C&I (3)	MUNICIPAL LIGHTING (4)	PRIVATE LIGHTING (5)
	PROPERTY TAXES							
1	HIGH TENSION ≥ 69 KV	D	D02	38,096	21,609	12,863	151	128
2	HIGH TENSION < 69 KV	D	D02A	315,678	181,666	108,143	1,267	1,079
3	TRANSFORMERS - OH DEMAND	D	D03	22,582	15,371	7,063	79	69
4	TRANSFORMERS - UG DEMAND	D	D03	12,039	8,194	3,765	42	37
5	TRANSFORMERS - OH CUSTOMER	C	C01	17,725	12,065	5,544	62	54
6	TRANSFORMERS - UG CUSTOMER	C	C01	11,776	8,016	3,683	41	36
7	OH LINES DEMAND	D	D03	35,219	23,973	11,015	124	107
8	UG LINES DEMAND	D	D03	2,771	1,886	867	10	8
9	OH LINES CUSTOMER	C	C01	39,572	26,935	12,377	139	120
10	UG LINES CUSTOMER	C	C01	714	486	223	3	2
11	SERVICES - OH	C	C02	10,483	6,070	3,614	0	13
12	SERVICES - UG	C	C02	26,125	15,128	9,005	0	33
13	METER & METER INSTALLATIONS	C	S01	16,104	10,558	5,373	0	36
14	INSTALL. ON CUSTR PREMISES	C	C03	1,023	0	0	0	0
15	STREET LIGHTING	C	C04	8,332	0	0	5,420	2,912
16	CUSTOMER ACCOUNTING	C	S02	2,521	2,194	302	1	22
17	UNCOLLECTIBLES	C	S03	0	0	0	0	0
18	CUSTOMER SERVICE	C	S04	753	656	88	0	8
19	REVENUES	R	R99	0	0	0	0	0
20				-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		426,385	252,699	143,716	1,673	1,429
22	TOTAL CUSTOMER	C		135,129	82,109	40,210	5,666	3,238
23	TOTAL REVENUE	R		0	0	0	0	0
24				-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL			561,514	334,807	183,926	7,340	4,666
				===========	===========	===========	===========	===========

				TOTAL PRIMARY (6)	RESID SC1 GENERAL (7)	RESID SC3 T.O.U. (8)	RESID SC5 W/ SP HTG (9)	C&I SC2 SEC NON DEM (10)
	PROPERTY TAXES							
1	HIGH TENSION ≥ 69 KV	D	D02	3,345	21,317	6	286	62
2	HIGH TENSION < 69 KV	D	D02A	23,524	179,213	50	2,403	518
3	TRANSFORMERS - OH DEMAND	D	D03	0	15,141	5	226	45
4	TRANSFORMERS - UG DEMAND	D	D03	0	8,072	2	120	24
5	TRANSFORMERS - OH CUSTOMER	C	C01	0	11,884	4	177	35
6	TRANSFORMERS - UG CUSTOMER	C	C01	0	7,896	2	118	23
7	OH LINES DEMAND	D	D03	0	23,613	7	352	70
8	UG LINES DEMAND	D	D03	0	1,858	1	28	6
9	OH LINES CUSTOMER	C	C01	0	26,532	8	396	79
10	UG LINES CUSTOMER	C	C01	0	479	0	7	1
11	SERVICES - OH	C	C02	786	5,988	2	80	17
12	SERVICES - UG	C	C02	1,959	14,924	4	200	43
13	METER & METER INSTALLATIONS	C	S01	136	10,182	16	359	155
14	INSTALL. ON CUSTR PREMISES	C	C03	1,023	0	0	0	0
15	STREET LIGHTING	C	C04	0	0	0	0	0
16	CUSTOMER ACCOUNTING	C	S02	1	2,135	1	59	46
17	UNCOLLECTIBLES	C	S03	0	0	0	0	0
18	CUSTOMER SERVICE	C	S04	0	638	0	17	16
19	REVENUES	R	R99	0	0	0	0	0
20				-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		26,868	249,214	71	3,414	724
22	TOTAL CUSTOMER	C		3,906	80,658	37	1,413	416
23	TOTAL REVENUE	R		0	0	0	0	0
24				-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL			30,774	329,872	108	4,828	1,140
				===========	===========	===========	===========	===========

				C&I SC2 SEC GEN SERV (11)	C&I SC2 SEC SPACE HTG (12)	C&I SC2 PRIMARY GEN (13)	SC4 MUNI STR LTG (14)	SC6 DUSK TO DAWN (15)	SC6 ENERGY LTG (16)
	PROPERTY TAXES								
1	HIGH TENSION ≥ 69 KV	D	D02	10,785	532	1,485	151	81	47
2	HIGH TENSION < 69 KV	D	D02A	90,672	4,470	12,483	1,267	681	399
3	TRANSFORMERS - OH DEMAND	D	D03	6,681	338	0	79	43	26
4	TRANSFORMERS - UG DEMAND	D	D03	3,561	180	0	42	23	14
5	TRANSFORMERS - OH CUSTOMER	C	C01	5,244	265	0	62	34	20
6	TRANSFORMERS - UG CUSTOMER	C	C01	3,484	176	0	41	22	14
7	OH LINES DEMAND	D	D03	10,419	526	0	124	67	41
8	UG LINES DEMAND	D	D03	820	41	0	10	5	3
9	OH LINES CUSTOMER	C	C01	11,706	592	0	139	75	46
10	UG LINES CUSTOMER	C	C01	211	11	0	3	1	1
11	SERVICES - OH	C	C02	3,030	149	417	0	0	13
12	SERVICES - UG	C	C02	7,551	372	1,039	0	0	33
13	METER & METER INSTALLATIONS	C	S01	4,987	95	135	0	0	36
14	INSTALL. ON CUSTR PREMISES	C	C03	0	0	0	0	0	0
15	STREET LIGHTING	C	C04	0	0	0	5,420	2,912	0
16	CUSTOMER ACCOUNTING	C	S02	248	6	3	1	19	3
17	UNCOLLECTIBLES	C	S03	0	0	0	0	0	0
18	CUSTOMER SERVICE	C	S04	70	2	1	0	7	1
19	REVENUES	R	R99	0	0	0	0	0	0
20				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		122,938	6,087	13,967	1,673	899	530
22	TOTAL CUSTOMER	C		36,531	1,668	1,596	5,666	3,070	168
23	TOTAL REVENUE	R		0	0	0	0	0	0
24				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL			159,469	7,754	15,563	7,340	3,969	698
				===========	===========	===========	===========	===========	===========

				SC7 PRIMARY T.O.U. (17)	SC7 SEP MET SP HTG (18)	SC7 HV TOD (19)
	PROPERTY TAXES					
1	HIGH TENSION ≥ 69 KV	D	D02	2,610	188	547
2	HIGH TENSION < 69 KV	D	D02A	21,942	1,581	0
3	TRANSFORMERS - OH DEMAND	D	D03	0	0	0
4	TRANSFORMERS - UG DEMAND	D	D03	0	0	0
5	TRANSFORMERS - OH CUSTOMER	C	C01	0	0	0
6	TRANSFORMERS - UG CUSTOMER	C	C01	0	0	0
7	OH LINES DEMAND	D	D03	0	0	0
8	UG LINES DEMAND	D	D03	0	0	0
9	OH LINES CUSTOMER	C	C01	0	0	0
10	UG LINES CUSTOMER	C	C01	0	0	0
11	SERVICES - OH	C	C02	733	53	0
12	SERVICES - UG	C	C02	1,827	132	0
13	METER & METER INSTALLATIONS	C	S01	76	36	24
14	INSTALL. ON CUSTR PREMISES	C	C03	775	248	0
15	STREET LIGHTING	C	C04	0	0	0
16	CUSTOMER ACCOUNTING	C	S02	1	0	0
17	UNCOLLECTIBLES	C	S03	0	0	0
18	CUSTOMER SERVICE	C	S04	0	0	0
19	REVENUES	R	R99	0	0	0
20				-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		24,552	1,769	547
22	TOTAL CUSTOMER	C		3,414	468	24
23	TOTAL REVENUE	R		0	0	0
24				-------------------	-------------------	-------------------
25	TOTAL			27,966	2,238	570
				===========	===========	===========

				TOTAL COMPANY (1)	TOTAL RESIDENTIAL (2)	TOTAL C&I (3)	MUNICIPAL LIGHTING (4)	PRIVATE LIGHTING (5)
	PAYROLL & MISC. TAXES							
1	HIGH TENSION ≥ 69 KV	D	D02	44,595	25,295	15,058	176	150
2	HIGH TENSION < 69 KV	D	D02A	398,175	229,140	136,404	1,598	1,361
3	TRANSFORMERS - OH DEMAND	D	D03	6,881	4,684	2,152	24	21
4	TRANSFORMERS - UG DEMAND	D	D03	3,668	2,497	1,147	13	11
5	TRANSFORMERS - OH CUSTOMER	C	C01	5,401	3,677	1,689	19	16
6	TRANSFORMERS - UG CUSTOMER	C	C01	3,588	2,443	1,122	13	11
7	OH LINES DEMAND	D	D03	103,004	70,112	32,216	362	314
8	UG LINES DEMAND	D	D03	1,268	863	397	4	4
9	OH LINES CUSTOMER	C	C01	115,734	78,776	36,197	407	352
10	UG LINES CUSTOMER	C	C01	327	222	102	1	1
11	SERVICES - OH	C	C02	29,934	17,333	10,318	0	38
12	SERVICES - UG	C	C02	10,135	5,868	3,493	0	13
13	METER & METER INSTALLATIONS	C	S01	15,250	9,999	5,088	0	34
14	INSTALL. ON CUSTR PREMISES	C	C03	312	0	0	0	0
15	STREET LIGHTING	C	C04	14,289	0	0	9,295	4,994
16	CUSTOMER ACCOUNTING	C	S02	209,306	182,181	25,100	60	1,843
17	UNCOLLECTIBLES	C	S03	0	0	0	0	0
18	CUSTOMER SERVICE	C	S04	62,556	54,480	7,347	22	670
19	REVENUES	R	S06	1,676,956	781,239	650,270	6,714	5,782
20				-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		557,592	332,592	187,374	2,179	1,861
22	TOTAL CUSTOMER	C		466,831	354,979	90,458	9,816	7,973
23	TOTAL REVENUE	R		1,676,956	781,239	650,270	6,714	5,782
24				-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL			2,701,379	1,468,810	928,101	18,709	15,616
				===========	===========	===========	===========	===========

				TOTAL PRIMARY (6)	RESID SC1 GENERAL (7)	RESID SC3 T.O.U. (8)	RESID SC5 W/ SP HTG (9)	C&I SC2 SEC NON DEM (10)
	PAYROLL & MISC. TAXES							
1	HIGH TENSION ≥ 69 KV	D	D02	3,915	24,954	7	335	72
2	HIGH TENSION < 69 KV	D	D02A	29,671	226,047	63	3,030	654
3	TRANSFORMERS - OH DEMAND	D	D03	0	4,614	1	69	14
4	TRANSFORMERS - UG DEMAND	D	D03	0	2,460	1	37	7
5	TRANSFORMERS - OH CUSTOMER	C	C01	0	3,621	1	54	11
6	TRANSFORMERS - UG CUSTOMER	C	C01	0	2,406	1	36	7
7	OH LINES DEMAND	D	D03	0	69,061	21	1,030	205
8	UG LINES DEMAND	D	D03	0	850	0	13	3
9	OH LINES CUSTOMER	C	C01	0	77,596	24	1,157	230
10	UG LINES CUSTOMER	C	C01	0	219	0	3	1
11	SERVICES - OH	C	C02	2,244	17,099	5	229	49
12	SERVICES - UG	C	C02	760	5,789	2	78	17
13	METER & METER INSTALLATIONS	C	S01	129	9,643	16	340	147
14	INSTALL. ON CUSTR PREMISES	C	C03	312	0	0	0	0
15	STREET LIGHTING	C	C04	0	0	0	0	0
16	CUSTOMER ACCOUNTING	C	S02	123	177,262	50	4,869	3,844
17	UNCOLLECTIBLES	C	S03	0	0	0	0	0
18	CUSTOMER SERVICE	C	S04	37	53,015	15	1,451	1,300
19	REVENUES	R	S06	232,951	764,887	293	16,059	5,478
20				-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		33,587	327,986	93	4,513	954
22	TOTAL CUSTOMER	C		3,604	346,650	112	8,217	5,605
23	TOTAL REVENUE	R		232,951	764,887	293	16,059	5,478
24				-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL			270,142	1,439,523	498	28,788	12,037
				===========	===========	===========	===========	===========

				C&I SC2 SEC GEN SERV (11)	C&I SC2 SEC SPACE HTG (12)	C&I SC2 PRIMARY GEN (13)	SC4 MUNI STR LTG (14)	SC6 DUSK TO DAWN (15)	SC6 ENERGY LTG (16)
	PAYROLL & MISC. TAXES								
1	HIGH TENSION ≥ 69 KV	D	D02	12,625	622	1,738	176	95	55
2	HIGH TENSION < 69 KV	D	D02A	114,368	5,638	15,745	1,598	858	503
3	TRANSFORMERS - OH DEMAND	D	D03	2,036	103	0	24	13	8
4	TRANSFORMERS - UG DEMAND	D	D03	1,085	55	0	13	7	4
5	TRANSFORMERS - OH CUSTOMER	C	C01	1,598	81	0	19	10	6
6	TRANSFORMERS - UG CUSTOMER	C	C01	1,062	54	0	13	7	4
7	OH LINES DEMAND	D	D03	30,472	1,540	0	362	195	119
8	UG LINES DEMAND	D	D03	375	19	0	4	2	1
9	OH LINES CUSTOMER	C	C01	34,237	1,730	0	407	219	134
10	UG LINES CUSTOMER	C	C01	97	5	0	1	1	0
11	SERVICES - OH	C	C02	8,651	426	1,191	0	0	38
12	SERVICES - UG	C	C02	2,929	144	403	0	0	13
13	METER & METER INSTALLATIONS	C	S01	4,723	90	128	0	0	34
14	INSTALL. ON CUSTR PREMISES	C	C03	0	0	0	0	0	0
15	STREET LIGHTING	C	C04	0	0	0	9,295	4,994	0
16	CUSTOMER ACCOUNTING	C	S02	20,570	467	219	60	1,553	290
17	UNCOLLECTIBLES	C	S03	0	0	0	0	0	0
18	CUSTOMER SERVICE	C	S04	5,834	144	69	22	580	90
19	REVENUES	R	S06	527,163	28,603	89,026	6,714	3,551	2,231
20				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		160,961	7,977	17,483	2,179	1,170	691
22	TOTAL CUSTOMER	C		79,701	3,142	2,011	9,816	7,364	609
23	TOTAL REVENUE	R		527,163	28,603	89,026	6,714	3,551	2,231
24				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL			767,824	39,721	108,519	18,709	12,085	3,531
				===========	===========	===========	===========	===========	===========

				SC7 PRIMARY T.O.U. (17)	SC7 SEP MET SP HTG (18)	SC7 HV TOD (19)
	PAYROLL & MISC. TAXES					
1	HIGH TENSION ≥ 69 KV	D	D02	3,055	220	640
2	HIGH TENSION < 69 KV	D	D02A	27,677	1,995	0
3	TRANSFORMERS - OH DEMAND	D	D03	0	0	0
4	TRANSFORMERS - UG DEMAND	D	D03	0	0	0
5	TRANSFORMERS - OH CUSTOMER	C	C01	0	0	0
6	TRANSFORMERS - UG CUSTOMER	C	C01	0	0	0
7	OH LINES DEMAND	D	D03	0	0	0
8	UG LINES DEMAND	D	D03	0	0	0
9	OH LINES CUSTOMER	C	C01	0	0	0
10	UG LINES CUSTOMER	C	C01	0	0	0
11	SERVICES - OH	C	C02	2,094	151	0
12	SERVICES - UG	C	C02	709	51	0
13	METER & METER INSTALLATIONS	C	S01	72	34	23
14	INSTALL. ON CUSTR PREMISES	C	C03	236	76	0
15	STREET LIGHTING	C	C04	0	0	0
16	CUSTOMER ACCOUNTING	C	S02	111	9	3
17	UNCOLLECTIBLES	C	S03	0	0	0
18	CUSTOMER SERVICE	C	S04	33	3	1
19	REVENUES	R	S06	178,922	5,779	48,250
20				-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		30,732	2,215	640
22	TOTAL CUSTOMER	C		3,255	323	27
23	TOTAL REVENUE	R		178,922	5,779	48,250
24				-------------------	-------------------	-------------------
25	TOTAL			212,908	8,317	48,917
				===========	===========	===========

			TOTAL COMPANY (1)	TOTAL RESIDENTIAL (2)	TOTAL C&I (3)	MUNICIPAL LIGHTING (4)	PRIVATE LIGHTING (5)
	TOTAL OPERATING EXPENSES						
1	HIGH TENSION ≥ 69 KV	D	2,468,045	1,399,928	833,355	9,764	8,315
2	HIGH TENSION < 69 KV	D	21,703,994	12,490,151	7,435,194	87,115	74,190
3	TRANSFORMERS - OH DEMAND	D	680,168	462,971	212,733	2,394	2,071
4	TRANSFORMERS - UG DEMAND	D	362,599	246,811	113,408	1,276	1,104
5	TRANSFORMERS - OH CUSTOMER	C	533,876	363,394	166,978	1,879	1,625
6	TRANSFORMERS - UG CUSTOMER	C	354,689	241,426	110,934	1,248	1,080
7	OH LINES DEMAND	D	4,909,413	3,341,696	1,535,494	17,276	14,947
8	UG LINES DEMAND	D	95,484	64,993	29,864	336	291
9	OH LINES CUSTOMER	C	5,516,119	3,754,663	1,725,250	19,411	16,795
10	UG LINES CUSTOMER	C	24,601	16,745	7,694	87	75
11	SERVICES - OH	C	1,429,504	827,753	492,749	0	1,816
12	SERVICES - UG	C	824,852	477,630	284,326	0	1,048
13	METER & METER INSTALLATIONS	C	923,989	605,814	308,305	0	2,078
14	INSTALL. ON CUSTR PREMISES	C	29,256	0	0	0	0
15	STREET LIGHTING	C	737,100	0	0	479,470	257,630
16	CUSTOMER ACCOUNTING	C	8,031,776	6,990,913	963,157	2,285	70,706
17	UNCOLLECTIBLES	C	611,945	339,347	223,087	8,240	4,466
18	CUSTOMER SERVICE	C	2,021,981	1,760,930	237,480	719	21,662
19	REVENUES	R	1,676,956	781,239	650,270	6,714	5,782
20			-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D	30,219,703	18,006,549	10,160,048	118,161	100,918
22	TOTAL CUSTOMER	C	21,039,686	15,378,616	4,519,960	513,339	378,981
23	TOTAL REVENUE	R	1,676,956	781,239	650,270	6,714	5,782
24			-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL		52,936,345	34,166,403	15,330,278	638,215	485,682
			===========	===========	===========	===========	===========

			TOTAL PRIMARY (6)	RESID SC1 GENERAL (7)	RESID SC3 T.O.U. (8)	RESID SC5 W/ SP HTG (9)	C&I SC2 SEC NON DEM (10)
	TOTAL OPERATING EXPENSES						
1	HIGH TENSION ≥ 69 KV	D	216,682	1,381,031	382	18,514	3,993
2	HIGH TENSION < 69 KV	D	1,617,344	12,321,556	3,412	165,183	35,622
3	TRANSFORMERS - OH DEMAND	D	0	456,031	141	6,799	1,351
4	TRANSFORMERS - UG DEMAND	D	0	243,111	75	3,624	720
5	TRANSFORMERS - OH CUSTOMER	C	0	357,947	111	5,336	1,060
6	TRANSFORMERS - UG CUSTOMER	C	0	237,808	73	3,545	704
7	OH LINES DEMAND	D	0	3,291,606	1,017	49,072	9,750
8	UG LINES DEMAND	D	0	64,019	20	954	190
9	OH LINES CUSTOMER	C	0	3,698,383	1,143	55,136	10,955
10	UG LINES CUSTOMER	C	0	16,494	5	246	49
11	SERVICES - OH	C	107,185	816,580	226	10,947	2,361
12	SERVICES - UG	C	61,848	471,183	130	6,317	1,362
13	METER & METER INSTALLATIONS	C	7,792	584,251	941	20,621	8,893
14	INSTALL. ON CUSTR PREMISES	C	29,256	0	0	0	0
15	STREET LIGHTING	C	0	0	0	0	0
16	CUSTOMER ACCOUNTING	C	4,714	6,802,159	1,904	186,850	147,494
17	UNCOLLECTIBLES	C	36,805	332,233	96	7,018	3,355
18	CUSTOMER SERVICE	C	1,190	1,713,567	470	46,893	42,024
19	REVENUES	R	232,951	764,887	293	16,059	5,478
20			-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D	1,834,026	17,757,355	5,048	244,147	51,625
22	TOTAL CUSTOMER	C	248,790	15,030,606	5,100	342,910	218,258
23	TOTAL REVENUE	R	232,951	764,887	293	16,059	5,478
24			-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL		2,315,767	33,552,848	10,441	603,115	275,360
			===========	===========	===========	===========	===========

			C&I SC2 SEC GEN SERV (11)	C&I SC2 SEC SPACE HTG (12)	C&I SC2 PRIMARY GEN (13)	SC4 MUNI STR LTG (14)	SC6 DUSK TO DAWN (15)	SC6 ENERGY LTG (16)
	TOTAL OPERATING EXPENSES							
1	HIGH TENSION ≥ 69 KV	D	698,727	34,444	96,192	9,764	5,244	3,071
2	HIGH TENSION < 69 KV	D	6,234,038	307,307	858,227	87,115	46,789	27,401
3	TRANSFORMERS - OH DEMAND	D	201,214	10,168	0	2,394	1,286	785
4	TRANSFORMERS - UG DEMAND	D	107,268	5,421	0	1,276	686	418
5	TRANSFORMERS - OH CUSTOMER	C	157,936	7,981	0	1,879	1,009	616
6	TRANSFORMERS - UG CUSTOMER	C	104,928	5,302	0	1,248	671	409
7	OH LINES DEMAND	D	1,452,352	73,391	0	17,276	9,283	5,664
8	UG LINES DEMAND	D	28,247	1,427	0	336	181	110
9	OH LINES CUSTOMER	C	1,631,834	82,461	0	19,411	10,430	6,364
10	UG LINES CUSTOMER	C	7,278	368	0	87	47	28
11	SERVICES - OH	C	413,145	20,366	56,877	0	0	1,816
12	SERVICES - UG	C	238,393	11,752	32,819	0	0	1,048
13	METER & METER INSTALLATIONS	C	286,165	5,472	7,774	0	0	2,078
14	INSTALL. ON CUSTR PREMISES	C	0	0	0	0	0	0
15	STREET LIGHTING	C	0	0	0	479,470	257,630	0
16	CUSTOMER ACCOUNTING	C	789,335	17,933	8,395	2,285	59,587	11,120
17	UNCOLLECTIBLES	C	188,055	7,834	23,843	8,240	3,528	938
18	CUSTOMER SERVICE	C	188,567	4,648	2,241	719	18,757	2,905
19	REVENUES	R	527,163	28,603	89,026	6,714	3,551	2,231
20			-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D	8,721,846	432,158	954,419	118,161	63,468	37,450
22	TOTAL CUSTOMER	C	4,005,637	164,117	131,948	513,339	351,659	27,323
23	TOTAL REVENUE	R	527,163	28,603	89,026	6,714	3,551	2,231
24			-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL		13,254,646	624,878	1,175,393	638,215	418,678	67,004
			===========	===========	===========	===========	===========	===========

			SC7 PRIMARY T.O.U. (17)	SC7 SEP MET SP HTG (18)	SC7 HV TOD (19)
	TOTAL OPERATING EXPENSES				
1	HIGH TENSION ≥ 69 KV	D	169,090	12,186	35,406
2	HIGH TENSION < 69 KV	D	1,508,618	108,726	0
3	TRANSFORMERS - OH DEMAND	D	0	0	0
4	TRANSFORMERS - UG DEMAND	D	0	0	0
5	TRANSFORMERS - OH CUSTOMER	C	0	0	0
6	TRANSFORMERS - UG CUSTOMER	C	0	0	0
7	OH LINES DEMAND	D	0	0	0
8	UG LINES DEMAND	D	0	0	0
9	OH LINES CUSTOMER	C	0	0	0
10	UG LINES CUSTOMER	C	0	0	0
11	SERVICES - OH	C	99,980	7,206	0
12	SERVICES - UG	C	57,690	4,158	0
13	METER & METER INSTALLATIONS	C	4,359	2,060	1,373
14	INSTALL. ON CUSTR PREMISES	C	22,170	7,087	0
15	STREET LIGHTING	C	0	0	0
16	CUSTOMER ACCOUNTING	C	4,248	332	133
17	UNCOLLECTIBLES	C	33,415	1,786	1,604
18	CUSTOMER SERVICE	C	1,079	83	28
19	REVENUES	R	178,922	5,779	48,250
20			-------------------	-------------------	-------------------
21	TOTAL DEMAND	D	1,677,708	120,912	35,406
22	TOTAL CUSTOMER	C	222,941	22,711	3,138
23	TOTAL REVENUE	R	178,922	5,779	48,250
24			-------------------	-------------------	-------------------
25	TOTAL		2,079,571	149,403	86,794
			===========	===========	===========

				TOTAL COMPANY (1)	TOTAL RESIDENTIAL (2)	TOTAL C&I (3)	MUNICIPAL LIGHTING (4)	PRIVATE LIGHTING (5)
	OPERATING REVENUES							
1	REVENUES FROM SALES	R	R01	65,010,326	36,050,702	23,699,810	875,398	474,466
2	OTHER ELECTRIC REVENUES	R	R02	150,527	10,071	49,645	15,114	8,192
3				-------------------	-------------------	-------------------	-------------------	-------------------
4	TOTAL OPERATING REVENUES			65,160,854	36,060,774	23,749,455	890,512	482,657
				===========	===========	===========	===========	===========

				TOTAL PRIMARY (6)	RESID SC1 GENERAL (7)	RESID SC3 T.O.U. (8)	RESID SC5 W/ SP HTG (9)	C&I SC2 SEC NON DEM (10)
	OPERATING REVENUES							
1	REVENUES FROM SALES	R	R01	3,909,950	35,294,980	10,155	745,567	356,439
2	OTHER ELECTRIC REVENUES	R	R02	67,505	9,860	3	208	100
3				-------------------	-------------------	-------------------	-------------------	-------------------
4	TOTAL OPERATING REVENUES			3,977,456	35,304,841	10,158	745,775	356,539
				===========	===========	===========	===========	===========

				C&I SC2 SEC GEN SERV (11)	C&I SC2 SEC SPACE HTG (12)	C&I SC2 PRIMARY GEN (13)	SC4 MUNI STR LTG (14)	SC6 DUSK TO DAWN (15)	SC6 ENERGY LTG (16)
	OPERATING REVENUES								
1	REVENUES FROM SALES	R	R01	19,978,153	832,258	2,532,959	875,398	374,775	99,691
2	OTHER ELECTRIC REVENUES	R	R02	5,581	233	43,732	15,114	6,470	1,721
3				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
4	TOTAL OPERATING REVENUES			19,983,735	832,491	2,576,690	890,512	381,245	101,412
				===========	===========	===========	===========	===========	===========

				SC7 PRIMARY T.O.U. (17)	SC7 SEP MET SP HTG (18)	SC7 HV TOD (19)
	OPERATING REVENUES					
1	REVENUES FROM SALES	R	R01	3,549,826	189,750	170,374
2	OTHER ELECTRIC REVENUES	R	R02	61,288	3,276	2,942
3				-------------------	-------------------	-------------------
4	TOTAL OPERATING REVENUES			3,611,114	193,026	173,315
				===========	===========	===========

				TOTAL COMPANY (1)	TOTAL RESIDENTIAL (2)	TOTAL C&I (3)	MUNICIPAL LIGHTING (4)	PRIVATE LIGHTING (5)
	FIT ADJUSTMENTS							
1	HIGH TENSION ≥ 69 KV	D	D02	(137,939)	(78,242)	(46,576)	(546)	(465)
2	HIGH TENSION < 69 KV	D	D02A	(1,126,931)	(648,523)	(386,056)	(4,523)	(3,852)
3	TRANSFORMERS - OH DEMAND	D	D03	(79,067)	(53,818)	(24,729)	(278)	(241)
4	TRANSFORMERS - UG DEMAND	D	D03	(42,151)	(28,691)	(13,183)	(148)	(128)
5	TRANSFORMERS - OH CUSTOMER	C	C01	(62,061)	(42,243)	(19,410)	(218)	(189)
6	TRANSFORMERS - UG CUSTOMER	C	C01	(41,231)	(28,065)	(12,896)	(145)	(126)
7	OH LINES DEMAND	D	D03	(159,980)	(108,894)	(50,036)	(563)	(487)
8	UG LINES DEMAND	D	D03	(8,967)	(6,103)	(2,804)	(32)	(27)
9	OH LINES CUSTOMER	C	C01	(179,751)	(122,351)	(56,220)	(633)	(547)
10	UG LINES CUSTOMER	C	C01	(2,310)	(1,572)	(723)	(8)	(7)
11	SERVICES - OH	C	C02	(49,876)	(28,881)	(17,192)	0	(63)
12	SERVICES - UG	C	C02	(104,658)	(60,602)	(36,076)	0	(133)
13	METER & METER INSTALLATIONS	C	S01	(50,890)	(33,366)	(16,980)	0	(114)
14	INSTALL. ON CUSTR PREMISES	C	C03	(3,291)	0	0	0	0
15	STREET LIGHTING	C	C04	(42,617)	0	0	(27,721)	(14,895)
16	CUSTOMER ACCOUNTING	C	S02	(73,554)	(64,022)	(8,820)	(21)	(648)
17	UNCOLLECTIBLES	C	S03	0	0	0	0	0
18	CUSTOMER SERVICE	C	S04	61,299	53,385	7,200	22	657
19	REVENUES	R	R99	0	0	0	0	0
20				-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		(1,555,035)	(924,272)	(523,385)	(6,090)	(5,200)
22	TOTAL CUSTOMER	C		(548,939)	(327,717)	(161,118)	(28,725)	(16,066)
23	TOTAL REVENUE	R		0	0	0	0	0
24				-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL			(2,103,974)	(1,251,989)	(684,503)	(34,815)	(21,266)
				===========	===========	===========	===========	===========

				TOTAL PRIMARY (6)	RESID SC1 GENERAL (7)	RESID SC3 T.O.U. (8)	RESID SC5 W/ SP HTG (9)	C&I SC2 SEC NON DEM (10)
	FIT ADJUSTMENTS							
1	HIGH TENSION ≥ 69 KV	D	D02	(12,110)	(77,186)	(21)	(1,035)	(223)
2	HIGH TENSION < 69 KV	D	D02A	(83,977)	(639,769)	(177)	(8,577)	(1,850)
3	TRANSFORMERS - OH DEMAND	D	D03	0	(53,012)	(16)	(790)	(157)
4	TRANSFORMERS - UG DEMAND	D	D03	0	(28,261)	(9)	(421)	(84)
5	TRANSFORMERS - OH CUSTOMER	C	C01	0	(41,610)	(13)	(620)	(123)
6	TRANSFORMERS - UG CUSTOMER	C	C01	0	(27,644)	(9)	(412)	(82)
7	OH LINES DEMAND	D	D03	0	(107,262)	(33)	(1,599)	(318)
8	UG LINES DEMAND	D	D03	0	(6,012)	(2)	(90)	(18)
9	OH LINES CUSTOMER	C	C01	0	(120,517)	(37)	(1,797)	(357)
10	UG LINES CUSTOMER	C	C01	0	(1,549)	(0)	(23)	(5)
11	SERVICES - OH	C	C02	(3,740)	(28,491)	(8)	(382)	(82)
12	SERVICES - UG	C	C02	(7,847)	(59,784)	(17)	(801)	(173)
13	METER & METER INSTALLATIONS	C	S01	(429)	(32,178)	(52)	(1,136)	(490)
14	INSTALL. ON CUSTR PREMISES	C	C03	(3,291)	0	0	0	0
15	STREET LIGHTING	C	C04	0	0	0	0	0
16	CUSTOMER ACCOUNTING	C	S02	(43)	(62,293)	(17)	(1,711)	(1,351)
17	UNCOLLECTIBLES	C	S03	0	0	0	0	0
18	CUSTOMER SERVICE	C	S04	36	51,949	14	1,422	1,274
19	REVENUES	R	R99	0	0	0	0	0
20				-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		(96,087)	(911,501)	(259)	(12,512)	(2,649)
22	TOTAL CUSTOMER	C		(15,314)	(322,118)	(139)	(5,461)	(1,388)
23	TOTAL REVENUE	R		0	0	0	0	0
24				-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL			(111,402)	(1,233,619)	(397)	(17,973)	(4,037)
				===========	===========	===========	===========	===========

				C&I SC2 SEC GEN SERV (11)	C&I SC2 SEC SPACE HTG (12)	C&I SC2 PRIMARY GEN (13)	SC4 MUNI STR LTG (14)	SC6 DUSK TO DAWN (15)	SC6 ENERGY LTG (16)
	FIT ADJUSTMENTS								
1	HIGH TENSION ≥ 69 KV	D	D02	(39,052)	(1,925)	(5,376)	(546)	(293)	(172)
2	HIGH TENSION < 69 KV	D	D02A	(323,688)	(15,956)	(44,562)	(4,523)	(2,429)	(1,423)
3	TRANSFORMERS - OH DEMAND	D	D03	(23,390)	(1,182)	0	(278)	(150)	(91)
4	TRANSFORMERS - UG DEMAND	D	D03	(12,469)	(630)	0	(148)	(80)	(49)
5	TRANSFORMERS - OH CUSTOMER	C	C01	(18,359)	(928)	0	(218)	(117)	(72)
6	TRANSFORMERS - UG CUSTOMER	C	C01	(12,197)	(616)	0	(145)	(78)	(48)
7	OH LINES DEMAND	D	D03	(47,327)	(2,392)	0	(563)	(303)	(185)
8	UG LINES DEMAND	D	D03	(2,653)	(134)	0	(32)	(17)	(10)
9	OH LINES CUSTOMER	C	C01	(53,176)	(2,687)	0	(633)	(340)	(207)
10	UG LINES CUSTOMER	C	C01	(683)	(35)	0	(8)	(4)	(3)
11	SERVICES - OH	C	C02	(14,415)	(711)	(1,984)	0	0	(63)
12	SERVICES - UG	C	C02	(30,248)	(1,491)	(4,164)	0	0	(133)
13	METER & METER INSTALLATIONS	C	S01	(15,761)	(301)	(428)	0	0	(114)
14	INSTALL. ON CUSTR PREMISES	C	C03	0	0	0	0	0	0
15	STREET LIGHTING	C	C04	0	0	0	(27,721)	(14,895)	0
16	CUSTOMER ACCOUNTING	C	S02	(7,229)	(164)	(77)	(21)	(546)	(102)
17	UNCOLLECTIBLES	C	S03	0	0	0	0	0	0
18	CUSTOMER SERVICE	C	S04	5,717	141	68	22	569	88
19	REVENUES	R	R99	0	0	0	0	0	0
20				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		(448,580)	(22,219)	(49,938)	(6,090)	(3,271)	(1,929)
22	TOTAL CUSTOMER	C		(146,351)	(6,792)	(6,586)	(28,725)	(15,412)	(654)
23	TOTAL REVENUE	R		0	0	0	0	0	0
24				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL			(594,931)	(29,011)	(56,523)	(34,815)	(18,683)	(2,583)
				===========	===========	===========	===========	===========	===========

				SC7 PRIMARY T.O.U. (17)	SC7 SEP MET SP HTG (18)	SC7 HV TOD (19)
	FIT ADJUSTMENTS					
1	HIGH TENSION ≥ 69 KV	D	D02	(9,450)	(681)	(1,979)
2	HIGH TENSION < 69 KV	D	D02A	(78,332)	(5,645)	0
3	TRANSFORMERS - OH DEMAND	D	D03	0	0	0
4	TRANSFORMERS - UG DEMAND	D	D03	0	0	0
5	TRANSFORMERS - OH CUSTOMER	C	C01	0	0	0
6	TRANSFORMERS - UG CUSTOMER	C	C01	0	0	0
7	OH LINES DEMAND	D	D03	0	0	0
8	UG LINES DEMAND	D	D03	0	0	0
9	OH LINES CUSTOMER	C	C01	0	0	0
10	UG LINES CUSTOMER	C	C01	0	0	0
11	SERVICES - OH	C	C02	(3,488)	(251)	0
12	SERVICES - UG	C	C02	(7,320)	(528)	0
13	METER & METER INSTALLATIONS	C	S01	(240)	(113)	(76)
14	INSTALL. ON CUSTR PREMISES	C	C03	(2,494)	(797)	0
15	STREET LIGHTING	C	C04	0	0	0
16	CUSTOMER ACCOUNTING	C	S02	(39)	(3)	(1)
17	UNCOLLECTIBLES	C	S03	0	0	0
18	CUSTOMER SERVICE	C	S04	33	3	1
19	REVENUES	R	R99	0	0	0
20				-------------------	-------------------	-------------------
21	TOTAL DEMAND	D		(87,782)	(6,326)	(1,979)
22	TOTAL CUSTOMER	C		(13,548)	(1,690)	(76)
23	TOTAL REVENUE	R		0	0	0
24				-------------------	-------------------	-------------------
25	TOTAL			(101,330)	(8,016)	(2,055)
				===========	===========	===========

			TOTAL COMPANY (1)	TOTAL RESIDENTIAL (2)	TOTAL C&I (3)	MUNICIPAL LIGHTING (4)	PRIVATE LIGHTING (5)
	FEDERAL INCOME TAX COMPUTATION						
1	HIGH TENSION ≥ 69 KV	D	(656,229)	(372,227)	(221,581)	(2,596)	(2,211)
2	HIGH TENSION < 69 KV	D	(5,684,770)	(3,271,455)	(1,947,446)	(22,817)	(19,432)
3	TRANSFORMERS - OH DEMAND	D	(221,902)	(151,042)	(69,403)	(781)	(676)
4	TRANSFORMERS - UG DEMAND	D	(118,297)	(80,521)	(36,999)	(416)	(360)
5	TRANSFORMERS - OH CUSTOMER	C	(174,175)	(118,556)	(54,476)	(613)	(530)
6	TRANSFORMERS - UG CUSTOMER	C	(115,716)	(78,764)	(36,192)	(407)	(352)
7	OH LINES DEMAND	D	(1,190,957)	(810,650)	(372,490)	(4,191)	(3,626)
8	UG LINES DEMAND	D	(29,018)	(19,752)	(9,076)	(102)	(88)
9	OH LINES CUSTOMER	C	(1,338,136)	(910,830)	(418,522)	(4,709)	(4,074)
10	UG LINES CUSTOMER	C	(7,476)	(5,089)	(2,338)	(26)	(23)
11	SERVICES - OH	C	(350,072)	(202,709)	(120,669)	0	(445)
12	SERVICES - UG	C	(277,877)	(160,905)	(95,784)	0	(353)
13	METER & METER INSTALLATIONS	C	(244,927)	(160,587)	(81,724)	0	(551)
14	INSTALL. ON CUSTR PREMISES	C	(9,435)	0	0	0	0
15	STREET LIGHTING	C	(197,408)	0	0	(128,410)	(68,998)
16	CUSTOMER ACCOUNTING	C	(1,760,227)	(1,532,114)	(211,084)	(501)	(15,496)
17	UNCOLLECTIBLES	C	(128,508)	(71,263)	(46,848)	(1,730)	(938)
18	CUSTOMER SERVICE	C	(363,317)	(316,410)	(42,671)	(129)	(3,892)
19	REVENUES	R	13,331,618	7,408,702	4,850,829	185,598	100,144
20			-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D	(7,901,173)	(4,705,647)	(2,656,996)	(30,904)	(26,393)
22	TOTAL CUSTOMER	C	(4,967,274)	(3,557,227)	(1,110,309)	(136,526)	(95,652)
23	TOTAL REVENUE	R	13,331,618	7,408,702	4,850,829	185,598	100,144
24			-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL		463,172	(854,171)	1,083,524	18,168	(21,901)
			===========	===========	===========	===========	===========

			TOTAL PRIMARY (6)	RESID SC1 GENERAL (7)	RESID SC3 T.O.U. (8)	RESID SC5 W/ SP HTG (9)	C&I SC2 SEC NON DEM (10)
	FEDERAL INCOME TAX COMPUTATION						
1	HIGH TENSION ≥ 69 KV	D	(57,614)	(367,203)	(102)	(4,923)	(1,062)
2	HIGH TENSION < 69 KV	D	(423,619)	(3,227,296)	(894)	(43,265)	(9,330)
3	TRANSFORMERS - OH DEMAND	D	0	(148,778)	(46)	(2,218)	(441)
4	TRANSFORMERS - UG DEMAND	D	0	(79,314)	(25)	(1,182)	(235)
5	TRANSFORMERS - OH CUSTOMER	C	0	(116,779)	(36)	(1,741)	(346)
6	TRANSFORMERS - UG CUSTOMER	C	0	(77,584)	(24)	(1,157)	(230)
7	OH LINES DEMAND	D	0	(798,499)	(247)	(11,904)	(2,365)
8	UG LINES DEMAND	D	0	(19,456)	(6)	(290)	(58)
9	OH LINES CUSTOMER	C	0	(897,178)	(277)	(13,375)	(2,657)
10	UG LINES CUSTOMER	C	0	(5,013)	(2)	(75)	(15)
11	SERVICES - OH	C	(26,249)	(199,973)	(55)	(2,681)	(578)
12	SERVICES - UG	C	(20,835)	(158,733)	(44)	(2,128)	(459)
13	METER & METER INSTALLATIONS	C	(2,066)	(154,871)	(249)	(5,466)	(2,357)
14	INSTALL. ON CUSTR PREMISES	C	(9,435)	0	0	0	0
15	STREET LIGHTING	C	0	0	0	0	0
16	CUSTOMER ACCOUNTING	C	(1,033)	(1,490,747)	(417)	(40,950)	(32,324)
17	UNCOLLECTIBLES	C	(7,729)	(69,769)	(20)	(1,474)	(705)
18	CUSTOMER SERVICE	C	(214)	(307,900)	(85)	(8,426)	(7,551)
19	REVENUES	R	786,346	7,253,390	2,072	153,241	73,723
20			-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D	(481,233)	(4,640,546)	(1,319)	(63,783)	(13,490)
22	TOTAL CUSTOMER	C	(67,560)	(3,478,545)	(1,209)	(77,472)	(47,223)
23	TOTAL REVENUE	R	786,346	7,253,390	2,072	153,241	73,723
24			-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL		237,553	(865,701)	(457)	11,986	13,010
			===========	===========	===========	===========	===========

			C&I SC2 SEC GEN SERV (11)	C&I SC2 SEC SPACE HTG (12)	C&I SC2 PRIMARY GEN (13)	SC4 MUNI STR LTG (14)	SC6 DUSK TO DAWN (15)	SC6 ENERGY LTG (16)
	FEDERAL INCOME TAX COMPUTATION							
1	HIGH TENSION ≥ 69 KV	D	(185,785)	(9,158)	(25,577)	(2,596)	(1,394)	(817)
2	HIGH TENSION < 69 KV	D	(1,632,836)	(80,491)	(224,789)	(22,817)	(12,255)	(7,177)
3	TRANSFORMERS - OH DEMAND	D	(65,645)	(3,317)	0	(781)	(420)	(256)
4	TRANSFORMERS - UG DEMAND	D	(34,996)	(1,768)	0	(416)	(224)	(136)
5	TRANSFORMERS - OH CUSTOMER	C	(51,526)	(2,604)	0	(613)	(329)	(201)
6	TRANSFORMERS - UG CUSTOMER	C	(34,232)	(1,730)	0	(407)	(219)	(134)
7	OH LINES DEMAND	D	(352,321)	(17,804)	0	(4,191)	(2,252)	(1,374)
8	UG LINES DEMAND	D	(8,584)	(434)	0	(102)	(55)	(33)
9	OH LINES CUSTOMER	C	(395,861)	(20,004)	0	(4,709)	(2,530)	(1,544)
10	UG LINES CUSTOMER	C	(2,212)	(112)	0	(26)	(14)	(9)
11	SERVICES - OH	C	(101,175)	(4,987)	(13,929)	0	0	(445)
12	SERVICES - UG	C	(80,310)	(3,959)	(11,056)	0	0	(353)
13	METER & METER INSTALLATIONS	C	(75,856)	(1,451)	(2,061)	0	0	(551)
14	INSTALL. ON CUSTR PREMISES	C	0	0	0	0	0	0
15	STREET LIGHTING	C	0	0	0	(128,410)	(68,998)	0
16	CUSTOMER ACCOUNTING	C	(172,989)	(3,930)	(1,840)	(501)	(13,059)	(2,437)
17	UNCOLLECTIBLES	C	(39,492)	(1,645)	(5,007)	(1,730)	(741)	(197)
18	CUSTOMER SERVICE	C	(33,882)	(835)	(403)	(129)	(3,370)	(522)
19	REVENUES	R	4,085,880	168,816	522,410	185,598	79,316	20,828
20			-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
21	TOTAL DEMAND	D	(2,280,167)	(112,972)	(250,366)	(30,904)	(16,600)	(9,794)
22	TOTAL CUSTOMER	C	(987,535)	(41,257)	(34,295)	(136,526)	(89,260)	(6,391)
23	TOTAL REVENUE	R	4,085,880	168,816	522,410	185,598	79,316	20,828
24			-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
25	TOTAL		818,178	14,587	237,749	18,168	(26,544)	4,643
			===========	===========	===========	===========	===========	===========

			SC7 PRIMARY T.O.U. (17)	SC7 SEP MET SP HTG (18)	SC7 HV TOD (19)
	FEDERAL INCOME TAX COMPUTATION				
1	HIGH TENSION ≥ 69 KV	D	(44,959)	(3,240)	(9,414)
2	HIGH TENSION < 69 KV	D	(395,142)	(28,478)	0
3	TRANSFORMERS - OH DEMAND	D	0	0	0
4	TRANSFORMERS - UG DEMAND	D	0	0	0
5	TRANSFORMERS - OH CUSTOMER	C	0	0	0
6	TRANSFORMERS - UG CUSTOMER	C	0	0	0
7	OH LINES DEMAND	D	0	0	0
8	UG LINES DEMAND	D	0	0	0
9	OH LINES CUSTOMER	C	0	0	0
10	UG LINES CUSTOMER	C	0	0	0
11	SERVICES - OH	C	(24,484)	(1,765)	0
12	SERVICES - UG	C	(19,435)	(1,401)	0
13	METER & METER INSTALLATIONS	C	(1,156)	(546)	(364)
14	INSTALL. ON CUSTR PREMISES	C	(7,149)	(2,285)	0
15	STREET LIGHTING	C	0	0	0
16	CUSTOMER ACCOUNTING	C	(931)	(73)	(29)
17	UNCOLLECTIBLES	C	(7,017)	(375)	(337)
18	CUSTOMER SERVICE	C	(194)	(15)	(5)
19	REVENUES	R	720,760	39,322	26,264
20			-------------------	-------------------	-------------------
21	TOTAL DEMAND	D	(440,101)	(31,718)	(9,414)
22	TOTAL CUSTOMER	C	(60,366)	(6,459)	(735)
23	TOTAL REVENUE	R	720,760	39,322	26,264
24			-------------------	-------------------	-------------------
25	TOTAL		220,294	1,145	16,115
			===========	===========	===========

		TOTAL COMPANY (1)	TOTAL RESIDENTIAL (2)	TOTAL C&I (3)	MUNICIPAL LIGHTING (4)	PRIVATE LIGHTING (5)
	CUSTOMER COST BY CLASS					
1	NUMBER OF CUSTOMERS	73,087	63,651	8,584	26	783
2						
3	RATE BASE	50,224,660	31,475,832	15,169,525	1,443,953	853,327
4						
5	TOTAL CUSTOMER OPERATING EXPS.	21,624,115	15,738,781	4,708,987	518,797	382,930
6	MONTHLY OP. EXPS. COST/CUST	24.66	20.61	45.71	1,662.81	40.75
7						
8	RETURN @ 5.78% (CUSTOMER)	2,900,507	1,817,750	876,050	83,389	49,280
9	F.I.T. PERCENT ON RETURN	3.94%				
10	INCOME TAX ON RETURN	114,225	71,585	34,500	3,284	1,941
11	TOTAL RETURN & F.I.T.	3,014,731	1,889,334	910,550	86,673	51,221
12	MONTHLY RET. F.I.T. COST/CUST	3.44	2.47	8.84	277.80	5.45
13						
14	MONTHLY CUSTOMER COSTS	28.09	23.08	54.55	1,940.61	46.21
		===========	===========	===========	===========	===========

		TOTAL PRIMARY (6)	RESID SC1 GENERAL (7)	RESID SC3 T.O.U. (8)	RESID SC5 W/ SP HTG (9)	C&I SC2 SEC NON DEM (10)
	CUSTOMER COST BY CLASS					
1	NUMBER OF CUSTOMERS	43	61,939	17	1,695	1,519
2						
3	RATE BASE	1,282,023	30,906,395	14,776	554,661	171,063
4						
5	TOTAL CUSTOMER OPERATING EXPS.	274,619	15,381,244	5,247	352,290	222,688
6	MONTHLY OP. EXPS. COST/CUST	532.21	20.69	25.72	17.32	12.22
7						
8	RETURN @ 5.78% (CUSTOMER)	74,038	1,784,864	853	32,032	9,879
9	F.I.T. PERCENT ON RETURN					
10	INCOME TAX ON RETURN	2,916	70,290	34	1,261	389
11	TOTAL RETURN & F.I.T.	76,953	1,855,154	887	33,293	10,268
12	MONTHLY RET. F.I.T. COST/CUST	149.13	2.50	4.35	1.64	0.56
13						
14	MONTHLY CUSTOMER COSTS	681.34	23.19	30.07	18.96	12.78
		===========	===========	===========	===========	===========

		C&I SC2 SEC GEN SERV (11)	C&I SC2 SEC SPACE HTG (12)	C&I SC2 PRIMARY GEN (13)	SC4 MUNI STR LTG (14)	SC6 DUSK TO DAWN (15)	SC6 ENERGY LTG (16)
	CUSTOMER COST BY CLASS						
1	NUMBER OF CUSTOMERS	6,816	168	81	26	678	105
2							
3	RATE BASE	13,825,244	624,576	548,642	1,443,953	788,940	64,387
4							
5	TOTAL CUSTOMER OPERATING EXPS.	4,171,548	171,990	142,761	518,797	354,667	28,264
6	MONTHLY OP. EXPS. COST/CUST	51.00	85.31	146.87	1,662.81	43.59	22.43
7							
8	RETURN @ 5.78% (CUSTOMER)	798,417	36,070	31,684	83,389	45,562	3,718
9	F.I.T. PERCENT ON RETURN						
10	INCOME TAX ON RETURN	31,442	1,420	1,248	3,284	1,794	146
11	TOTAL RETURN & F.I.T.	829,859	37,490	32,932	86,673	47,356	3,865
12	MONTHLY RET. F.I.T. COST/CUST	10.15	18.60	33.88	277.80	5.82	3.07
13							
14	MONTHLY CUSTOMER COSTS	61.15	103.91	180.75	1,940.61	49.41	25.50
		===========	===========	===========	===========	===========	===========

		SC7 PRIMARY T.O.U. (17)	SC7 SEP MET SP HTG (18)	SC7 HV TOD (19)
	CUSTOMER COST BY CLASS			
1	NUMBER OF CUSTOMERS	39	3	1
2				
3	RATE BASE	1,122,104	149,855	10,063
4				
5	TOTAL CUSTOMER OPERATING EXPS.	243,928	23,625	7,066
6	MONTHLY OP. EXPS. COST/CUST	521.21	656.24	588.87
7				
8	RETURN @ 5.78% (CUSTOMER)	64,802	8,654	581
9	F.I.T. PERCENT ON RETURN			
10	INCOME TAX ON RETURN	2,552	341	23
11	TOTAL RETURN & F.I.T.	67,354	8,995	604
12	MONTHLY RET. F.I.T. COST/CUST	143.92	249.86	50.34
13				
14	MONTHLY CUSTOMER COSTS	665.13	906.11	639.21
		===========	===========	===========

			TOTAL COMPANY (1)	TOTAL RESIDENTIAL (2)	TOTAL C&I (3)	MUNICIPAL LIGHTING (4)	PRIVATE LIGHTING (5)
	ALLOCATION FACTORS						
1	HIGH TENSION - 60 HZ FOR ABOVE 69KV		425,913	241,587	143,813	1,685	1,435
2	PERCENT	D02	100.000000%	56.722147%	33.765816%	0.395621%	0.336923%
4	HIGH TENSION - 60 HZ FOR BELOW 69KV		419,803	241,587	143,813	1,685	1,435
5	PERCENT	D02A	100.000000%	57.547707%	34.257259%	0.401379%	0.341827%
7	LOW TENSION - OH & UG		441,598	300,583	138,117	1,554	1,345
8	PERCENT	D03	100.000000%	68.067111%	31.276523%	0.351904%	0.304462%
10	KWH SALES		1,592,895,983	742,077,890	617,673,807	6,377,481	5,492,564
11	PERCENT	E01	100.000000%	46.586714%	38.776782%	0.400370%	0.344816%
13	BOOK COST - OH & UG LINES CUST.		22,227,383	15,129,538	6,951,953	78,219	67,674
14	PERCENT	C01	100.000000%	68.067111%	31.276523%	0.351904%	0.304462%
16	BOOK COST - SERVICES OH & UG		20,648,868	11,956,718	7,117,649	0	26,231
17	PERCENT	C02	100.000000%	57.904955%	34.469923%	0.000000%	0.127033%
19	BOOK COST-INSTALL. ON CUST. PREM.		582,740	0	0	0	0
20	PERCENT	C03	100.000000%	0.000000%	0.000000%	0.000000%	0.000000%
22	BOOK COST-STREET LIGHTING		4,664,034	0	0	3,033,867	1,630,167
23	PERCENT	C04	100.000000%	0.000000%	0.000000%	65.048137%	34.951863%
25	BOOK COST-METERS & METER INSTALL		9,099,423	5,966,041	3,036,182	0	20,461
26	PERCENT	S01	100.000000%	65.565048%	33.366750%	0.000000%	0.224865%
28	CUSTOMER ACCOUNTS EXPENSE		4,677,881	4,071,660	560,964	1,331	41,181
29	PERCENT	S02	100.000000%	87.040695%	11.991835%	0.028450%	0.880333%
31	UNCOLLECTIBLES ACCOUNTS		611,945	339,347	223,087	8,240	4,466
32	PERCENT	S03	100.000000%	55.453809%	36.455454%	1.346552%	0.729831%
34	CUSTOMER SERVICE EXPENSES		1,016,512	885,273	119,388	362	10,890
35	PERCENT	S04	100.000000%	87.089359%	11.744907%	0.035574%	1.071326%
37	REVENUES-PAYROLL & MISC.		1,676,956	781,239	650,270	6,714	5,782
38	PERCENT	S06	100.000000%	46.586714%	38.776782%	0.400370%	0.344816%
40	REVENUES FROM SALES		65,010,326	36,050,702	23,699,810	875,398	474,466
41	PERCENT	R01	100.000000%	55.453809%	36.455454%	1.346552%	0.729831%
43	OTHER ELECTRIC REVENUES		150,527	10,071	49,645	15,114	8,192
44	PERCENT	R02	100.000000%	6.690752%	32.980714%	10.040561%	5.441984%
46	NULL REVENUE FACTOR		0	0	0	0	0
47	PERCENT	R99	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
49	NUMBER OF CUSTOMERS	K01	73,087	63,651	8,584	26	783

Line			TOTAL PRIMARY (6)	RESID SC1 GENERAL (7)	RESID SC3 T.O.U. (8)	RESID SC5 W/ SP HTG (9)	C&I SC2 SEC NON DEM (10)
	ALLOCATION FACTORS						
1	HIGH TENSION - 60 HZ FOR ABOVE 69KV		37,393	238,326	66	3,195	689
2	PERCENT	D02	8.779493%	55.956498%	0.015496%	0.750153%	0.161770%
3							
4	HIGH TENSION - 60 HZ FOR BELOW 69KV		31,283	238,326	66	3,195	689
5	PERCENT	D02A	7.451829%	56.770914%	0.015722%	0.761071%	0.164125%
6							
7	LOW TENSION - OH & UG		0	296,078	92	4,414	877
8	PERCENT	D03	0.000000%	67.046839%	0.020720%	0.999552%	0.198597%
9							
10	KWH SALES		221,274,241	726,545,879	278,431	15,253,580	5,203,602
11	PERCENT	E01	13.891318%	45.611634%	0.017480%	0.957601%	0.326676%
12							
13	BOOK COST - OH & UG LINES CUST.		0	14,902,758	4,606	222,174	44,143
14	PERCENT	C01	0.000000%	67.046839%	0.020720%	0.999552%	0.198597%
15							
16	BOOK COST - SERVICES OH & UG		1,548,270	11,795,323	3,266	158,128	34,100
17	PERCENT	C02	7.498089%	57.123340%	0.015819%	0.765796%	0.165143%
18							
19	BOOK COST-INSTALL. ON CUST. PREM.		582,740	0	0	0	0
20	PERCENT	C03	100.000000%	0.000000%	0.000000%	0.000000%	0.000000%
21							
22	BOOK COST-STREET LIGHTING		0	0	0	0	0
23	PERCENT	C04	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
24							
25	BOOK COST-METERS & METER INSTALL		76,739	5,753,698	9,263	203,080	87,583
26	PERCENT	S01	0.843338%	63.231458%	0.101800%	2.231790%	0.962509%
27							
28	CUSTOMER ACCOUNTS EXPENSE		2,745	3,961,725	1,109	108,825	85,904
29	PERCENT	S02	0.058687%	84.690603%	0.023710%	2.326381%	1.836379%
30							
31	UNCOLLECTIBLES ACCOUNTS		36,805	332,233	96	7,018	3,355
32	PERCENT	S03	6.014353%	54.291344%	0.015621%	1.146844%	0.548281%
33							
34	CUSTOMER SERVICE EXPENSES		598	861,463	236	23,574	21,127
35	PERCENT	S04	0.058834%	84.746945%	0.023260%	2.319154%	2.078345%
36							
37	REVENUES-PAYROLL & MISC.		232,951	764,887	293	16,059	5,478
38	PERCENT	S06	13.891318%	45.611634%	0.017480%	0.957601%	0.326676%
39							
40	REVENUES FROM SALES		3,909,950	35,294,980	10,155	745,567	356,439
41	PERCENT	R01	6.014353%	54.291344%	0.015621%	1.146844%	0.548281%
42							
43	OTHER ELECTRIC REVENUES		67,505	9,860	3	208	100
44	PERCENT	R02	44.845989%	6.550496%	0.001885%	0.138372%	0.066153%
45							
46	NULL REVENUE FACTOR		0	0	0	0	0
47	PERCENT	R99	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
48							
49	NUMBER OF CUSTOMERS	K01	43	61,939	17	1,695	1,519

			C&I SC2 SEC GEN SERV (11)	C&I SC2 SEC SPACE HTG (12)	C&I SC2 PRIMARY GEN (13)	SC4 MUNI STR LTG (14)	SC6 DUSK TO DAWN (15)	SC6 ENERGY LTG (16)
	ALLOCATION FACTORS							
1	HIGH TENSION - 60 HZ FOR ABOVE 69KV		120,580	5,944	16,600	1,685	905	530
2	PERCENT	D02	28.310946%	1.395590%	3.897510%	0.395621%	0.212485%	0.124439%
3								
4	HIGH TENSION - 60 HZ FOR BELOW 69KV		120,580	5,944	16,600	1,685	905	530
5	PERCENT	D02A	28.722996%	1.415902%	3.954236%	0.401379%	0.215577%	0.126250%
6								
7	LOW TENSION - OH & UG		130,638	6,602	0	1,554	835	510
8	PERCENT	D03	29.583014%	1.494912%	0.000000%	0.351904%	0.189086%	0.115376%
9								
10	KWH SALES		500,738,006	27,169,160	84,563,039	6,377,481	3,373,135	2,119,429
11	PERCENT	E01	31.435700%	1.705646%	5.308761%	0.400370%	0.211761%	0.133055%
12								
13	BOOK COST - OH & UG LINES CUST.		6,575,530	332,280	0	78,219	42,029	25,645
14	PERCENT	C01	29.583014%	1.494912%	0.000000%	0.351904%	0.189086%	0.115376%
15								
16	BOOK COST - SERVICES OH & UG		5,967,792	294,183	821,574	0	0	26,231
17	PERCENT	C02	28.901305%	1.424692%	3.978783%	0.000000%	0.000000%	0.127033%
18								
19	BOOK COST-INSTALL. ON CUST. PREM.		0	0	0	0	0	0
20	PERCENT	C03	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
21								
22	BOOK COST-STREET LIGHTING		0	0	0	3,033,867	1,630,167	0
23	PERCENT	C04	0.000000%	0.000000%	0.000000%	65.048137%	34.951863%	0.000000%
24								
25	BOOK COST-METERS & METER INSTALL		2,818,153	53,892	76,554	0	0	20,461
26	PERCENT	S01	30.970672%	0.592263%	0.841306%	0.000000%	0.000000%	0.224865%
27								
28	CUSTOMER ACCOUNTS EXPENSE		459,726	10,445	4,890	1,331	34,704	6,476
29	PERCENT	S02	9.827653%	0.223278%	0.104525%	0.028450%	0.741885%	0.138449%
30								
31	UNCOLLECTIBLES ACCOUNTS		188,055	7,834	23,843	8,240	3,528	938
32	PERCENT	S03	30.730738%	1.280194%	3.896241%	1.346552%	0.576485%	0.153346%
33								
34	CUSTOMER SERVICE EXPENSES		94,799	2,337	1,127	362	9,430	1,460
35	PERCENT	S04	9.325872%	0.229863%	0.110827%	0.035574%	0.927662%	0.143664%
36								
37	REVENUES-PAYROLL & MISC.		527,163	28,603	89,026	6,714	3,551	2,231
38	PERCENT	S06	31.435700%	1.705646%	5.308761%	0.400370%	0.211761%	0.133055%
39								
40	REVENUES FROM SALES		19,978,153	832,258	2,532,959	875,398	374,775	99,691
41	PERCENT	R01	30.730738%	1.280194%	3.896241%	1.346552%	0.576485%	0.153346%
42								
43	OTHER ELECTRIC REVENUES		5,581	233	43,732	15,114	6,470	1,721
44	PERCENT	R02	3.707802%	0.154461%	29.052298%	10.040561%	4.298559%	1.143424%
45								
46	NULL REVENUE FACTOR		0	0	0	0	0	0
47	PERCENT	R99	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
48								
49	NUMBER OF CUSTOMERS	K01	6,816	168	81	26	678	105

		SC7 PRIMARY T.O.U. (17)	SC7 SEP MET SP HTG (18)	SC7 HV TOD (19)
ALLOCATION FACTORS				
HIGH TENSION - 60 HZ FOR ABOVE 69KV		29,180	2,103	6,110
PERCENT	D02	6.851164%	0.493763%	1.434565%
HIGH TENSION - 60 HZ FOR BELOW 69KV		29,180	2,103	0
PERCENT	D02A	6.950879%	0.500949%	0.000000%
LOW TENSION - OH & UG		0	0	0
PERCENT	D03	0.000000%	0.000000%	0.000000%
KWH SALES		169,952,948	5,489,759	45,831,534
PERCENT	E01	10.669432%	0.344640%	2.877246%
BOOK COST - OH & UG LINES CUST.		0	0	0
PERCENT	C01	0.000000%	0.000000%	0.000000%
BOOK COST - SERVICES OH & UG		1,444,188	104,082	0
PERCENT	C02	6.994029%	0.504059%	0.000000%
BOOK COST-INSTALL. ON CUST. PREM.		441,586	141,154	0
PERCENT	C03	75.777521%	24.222479%	0.000000%
BOOK COST-STREET LIGHTING		0	0	0
PERCENT	C04	0.000000%	0.000000%	0.000000%
BOOK COST-METERS & METER INSTALL		42,930	20,285	13,524
PERCENT	S01	0.471789%	0.222929%	0.148620%
CUSTOMER ACCOUNTS EXPENSE		2,474	193	78
PERCENT	S02	0.052891%	0.004134%	0.001662%
UNCOLLECTIBLES ACCOUNTS		33,415	1,786	1,604
PERCENT	S03	5.460404%	0.291877%	0.262072%
CUSTOMER SERVICE EXPENSES		542	42	14
PERCENT	S04	0.053361%	0.004105%	0.001368%
REVENUES-PAYROLL & MISC.		178,922	5,779	48,250
PERCENT	S06	10.669432%	0.344640%	2.877246%
REVENUES FROM SALES		3,549,826	189,750	170,374
PERCENT	R01	5.460404%	0.291877%	0.262072%
OTHER ELECTRIC REVENUES		61,288	3,276	2,942
PERCENT	R02	40.715473%	2.176381%	1.954135%
NULL REVENUE FACTOR		0	0	0
PERCENT	R99	0.000000%	0.000000%	0.000000%
NUMBER OF CUSTOMERS	K01	39	3	1

EXHIBIT P-8
TABLE 1A

Rockland Electric Company
2016 Embedded Cost-Of-Service Study Results at April 19 Rates
Company Sponsored Methodology

Service Classification	Rate of Return %		Initial Surplus/Deficiency*	Adjustment*	Adjusted Surplus/Deficiency*
TOTAL RESIDENTIAL	2.24%		(4,612,428)	(297,726)	(4,910,154)
TOTAL C&I	10.98%		3,910,957	-	3,910,957
MUNICIPAL LIGHTING	11.45%		131,899	-	131,899
PRIVATE LIGHTING	1.38%		(69,754)	(3,160)	(72,914)
TOTAL PRIMARY	13.17%		941,811	(1,600)	940,211
RESID SC1 GENERAL	2.17%	$	(4,631,690)	(297,640)	(4,929,330)
RESID SC3 W/SP & OR W/WT HTG. T.O.U.	0.43%	$	(2,428)	(86)	(2,514)
RESID SC5 W/SP HTG	7.31%	$	21,691	-	21,691
C&I SC2 SECONDARY NON DEM MET	15.77%	$	51,538	-	51,538
C&I SC2 GENERAL SERVICE SEC	10.18%	$	2,811,702	-	2,811,702
C&I SC2 GENERAL SVC. SPACE HTG	6.85%	$	17,865	-	17,865
C&I SC2 GENERAL SVC. PRIMARY	21.12%	$	1,029,853	-	1,029,853
SC4 MUNI STREET LTG	11.45%	$	131,899	-	131,899
SC6 DUSK TO DAWN OH LIGHTING	-0.98%	$	(86,940)	(3,160)	(90,100)
SC6 ENERGY LTG	11.68%	$	17,186	-	17,186
SC7 C&I PRIMARY T.O.U.	13.32%	$	868,423	-	868,423
SC7 C&I SEP. METERED SP. HTG.	5.46%	$	-	(1,600)	(1,600)
SC7 HV TOD	35.98%	$	73,388	-	73,388
Total System			302,486	(302,486)	(0)
				(302,486)	

* Deficiencies shown as negative

EXHIBIT P-8
Schedule 2

ROCKLAND ELECTRIC COMPANY
STAFF – ENDORSED EMBEDDED
COST OF SERVICE STUDY
YEAR 2016

RATES IN EFFECT
APRIL 1, 2019

		TOTAL COMPANY (1)	TOTAL RESIDENTIAL (2)	TOTAL C&I (3)	MUNICIPAL LIGHTING (4)	PRIVATE LIGHTING (5)
	RATE OF RETURN STATEMENT					
1	TOTAL OPERATING REVENUES	65,160,854	36,060,774	23,749,455	890,512	482,657
2						
3	OPERATING EXPENSES					
4	OPERATION & MAINTENANCE	48,992,174	29,331,418	15,882,026	624,255	455,779
5	DEPRECIATION	681,279	380,302	241,178	10,925	6,877
6	PROPERTY TAXES	561,514	309,425	202,148	7,528	4,801
7	PAYROLL & MISC. TAXES	2,701,379	1,408,474	971,149	19,243	15,401
8	FEDERAL INCOME TAX	463,172	(209,483)	618,179	12,664	(22,308)
9		-------------------	-------------------	-------------------	-------------------	-------------------
10	TOTAL OPERATING EXPENSES	53,399,518	31,220,136	17,914,681	674,615	460,551
11						
12	UTILITY OPERATING INCOME	11,761,336	4,840,638	5,834,774	215,897	22,106
13						
14	UTILITY RATE BASE	203,657,206	113,291,221	73,585,911	2,117,793	1,418,560
15						
16	RATE OF RETURN (%)	5.78%	4.27%	7.93%	10.19%	1.56%
17						
18	INDEX	1.00	0.74	1.37	1.77	0.27
19						
20	DEVIATION	0.00	-1.50	2.15	4.42	-4.22
21						
22	TOLERANCE BAND +10%	6.35%				
23	TOLERANCE BAND -10%	5.20%				
24						
25	REVENUE SURPLUS	1,740,449	17,820	1,588,008	102,991	11,674
26	REVENUE DEFICIENCY	1,533,138	1,372,066	72,641	0	81,026
		===========	===========	===========	===========	===========

		TOTAL PRIMARY (6)	RESID SC1 GENERAL (7)	RESID SC3 T.O.U. (8)	RESID SC5 W/ SP HTG (9)	C&I SC2 SEC NON DEM (10)
	RATE OF RETURN STATEMENT					
1	TOTAL OPERATING REVENUES	3,977,456	35,304,841	10,158	745,775	356,539
2						
3	OPERATING EXPENSES					
4	OPERATION & MAINTENANCE	2,698,695	28,762,653	9,646	559,119	252,741
5	DEPRECIATION	41,997	373,333	159	6,810	2,200
6	PROPERTY TAXES	37,613	304,122	110	5,192	1,530
7	PAYROLL & MISC. TAXES	287,110	1,379,577	496	28,401	11,492
8	FEDERAL INCOME TAX	64,120	(219,565)	(460)	10,542	11,975
9		------------------	------------------	------------------	------------------	------------------
10	TOTAL OPERATING EXPENSES	3,129,535	30,600,121	9,951	610,064	279,938
11						
12	UTILITY OPERATING INCOME	847,921	4,704,719	207	135,712	76,601
13						
14	UTILITY RATE BASE	13,243,721	111,335,647	40,859	1,914,716	571,964
15						
16	RATE OF RETURN (%)	6.40%	4.23%	0.51%	7.09%	13.39%
17						
18	INDEX	1.11	0.73	0.09	1.23	2.32
19						
20	DEVIATION	0.63	-1.55	-5.27	1.31	7.62
21						
22	TOLERANCE BAND +10%					
23	TOLERANCE BAND -10%					
24						
25	REVENUE SURPLUS	19,957	0	0	17,820	50,970
26	REVENUE DEFICIENCY	7,406	1,369,641	2,426	0	0
		===========	===========	===========	===========	===========

		C&I SC2 SEC GEN SERV (11)	C&I SC2 SEC SPACE HTG (12)	C&I SC2 PRIMARY GEN (13)	SC4 MUNI STR LTG (14)	SC6 DUSK TO DAWN (15)	SC6 ENERGY LTG (16)
	RATE OF RETURN STATEMENT						
1	TOTAL OPERATING REVENUES	19,983,735	832,491	2,576,690	890,512	381,245	101,412
2							
3	OPERATING EXPENSES						
4	OPERATION & MAINTENANCE	13,651,588	673,972	1,303,726	624,255	389,848	65,932
5	DEPRECIATION	208,563	10,237	20,178	10,925	5,943	935
6	PROPERTY TAXES	173,697	8,794	18,126	7,528	4,055	746
7	PAYROLL & MISC. TAXES	802,640	42,123	114,893	19,243	11,791	3,611
8	FEDERAL INCOME TAX	445,157	(11,587)	172,635	12,664	(25,874)	3,567
9		-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
10	TOTAL OPERATING EXPENSES	15,281,646	723,539	1,629,558	674,615	385,762	74,789
11							
12	UTILITY OPERATING INCOME	4,702,089	108,952	947,133	215,897	(4,517)	26,623
13							
14	UTILITY RATE BASE	63,393,227	3,200,306	6,420,413	2,117,793	1,144,643	273,917
15							
16	RATE OF RETURN (%)	7.42%	3.40%	14.75%	10.19%	-0.39%	9.72%
17							
18	INDEX	1.28	0.59	2.55	1.77	-0.07	1.68
19							
20	DEVIATION	1.64	-2.37	8.98	4.42	-6.17	3.94
21							
22	TOLERANCE BAND +10%						
23	TOLERANCE BAND -10%						
24							
25	REVENUE SURPLUS	854,416	0	682,622	102,991	0	11,674
26	REVENUE DEFICIENCY	0	72,641	0	0	81,026	0
		===========	===========	===========	===========	===========	===========

		SC7 PRIMARY T.O.U. (17)	SC7 SEP MET SP HTG (18)	SC7 HV TOD (19)
	RATE OF RETURN STATEMENT			
1	TOTAL OPERATING REVENUES	3,611,114	193,026	173,315
2				
3	OPERATING EXPENSES			
4	OPERATION & MAINTENANCE	2,460,712	127,431	110,553
5	DEPRECIATION	38,698	2,361	937
6	PROPERTY TAXES	34,790	1,995	828
7	PAYROLL & MISC. TAXES	227,892	8,226	50,993
8	FEDERAL INCOME TAX	58,948	4,219	953
9		------------------	------------------	------------------
10	TOTAL OPERATING EXPENSES	2,821,039	144,232	164,265
11				
12	UTILITY OPERATING INCOME	790,076	48,795	9,051
13				
14	UTILITY RATE BASE	12,264,316	692,711	286,694
15				
16	RATE OF RETURN (%)	6.44%	7.04%	3.16%
17				
18	INDEX	1.12	1.22	0.55
19				
20	DEVIATION	0.67	1.27	-2.62
21				
22	TOLERANCE BAND +10%			
23	TOLERANCE BAND -10%			
24				
25	REVENUE SURPLUS	13,894	6,063	0
26	REVENUE DEFICIENCY	0	0	7,406
		===========	===========	===========

				TOTAL COMPANY (1)	TOTAL RESIDENTIAL (2)	TOTAL C&I (3)	MUNICIPAL LIGHTING (4)	PRIVATE LIGHTING (5)
	PLANT IN SERVICE							
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	12,236,780	6,940,964	4,131,848	48,411	41,229
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	9,231,255	4,300,538	3,579,584	36,959	31,831
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	101,167,422	58,219,531	34,657,185	406,065	345,818
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	76,319,283	36,607,946	30,470,884	314,612	270,957
5								
6	TRANSFORMERS - OH - DEMAND	D	AP2D	13,084,046	8,488,694	4,485,724	59,206	50,422
7	TRANSFORMERS - OH - ENERGY	E	AP2E	9,870,421	5,700,082	4,079,162	48,987	42,190
8	TRANSFORMERS - UG - DEMAND	D	AP2D	7,730,390	5,015,338	2,650,281	34,981	29,791
9	TRANSFORMERS - UG - ENERGY	E	AP2E	5,831,697	3,367,754	2,410,073	28,943	24,927
10								
11	OH LINES DEMAND	D	AP2D	23,509,185	15,252,337	8,059,870	106,381	90,597
12	OH LINES ENERGY	E	AP2E	17,734,999	10,241,808	7,329,367	88,019	75,806
13	UG LINES DEMAND	D	AP2D	1,129,064	732,517	387,087	5,109	4,351
14	UG LINES ENERGY	E	AP2E	851,750	491,878	352,004	4,227	3,641
15								
16	SERVICES - OH - DEMAND	C	C02	3,298,129	1,909,780	1,136,863	0	4,190
17	SERVICES - OH - ENERGY	C	E02	2,488,063	1,202,673	1,001,053	0	0
18	SERVICES - UG - DEMAND	C	C02	8,471,841	4,905,616	2,920,237	0	10,762
19	SERVICES - UG - ENERGY	C	E02	6,391,038	3,089,282	2,571,386	0	0
20								
21	METER & METER INSTALLATIONS	C	S01	9,099,500	5,966,092	3,036,208	0	20,462
22	INSTALL. ON CUSTR PREMISES	C	C03	582,742	0	0	0	0
23	STREET LIGHTING	C	C04	4,664,106	0	0	3,033,914	1,630,192
24	CUSTOMER ACCOUNTING	C	S02	1,058	921	127	0	9
25	UNCOLLECTIBLES	R	S03	0	0	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	E01	316	147	123	1	1
27	REVENUES	R	R99	0	0	0	0	0
28				-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		158,856,886	94,649,381	54,371,996	660,152	562,207
30	TOTAL ENERGY	E		119,839,722	60,710,155	48,221,197	521,748	449,352
31	TOTAL CUSTOMER	C		34,996,477	17,074,363	10,665,873	3,033,914	1,665,615
32	TOTAL REVENUE	R		0	0	0	0	0
33				-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL			313,693,085	172,433,899	113,259,065	4,215,815	2,677,174
				===========	===========	===========	===========	===========

				TOTAL PRIMARY (6)	RESID SC1 GENERAL (7)	RESID SC3 T.O.U. (8)	RESID SC5 W/ SP HTG (9)	C&I SC2 SEC NON DEM (10)
	PLANT IN SERVICE							
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	1,074,327	6,847,273	1,896	91,795	19,795
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	1,282,343	4,210,526	1,614	88,399	30,156
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	7,538,823	57,433,670	15,905	769,956	166,041
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	8,654,883	35,841,726	13,735	752,485	256,702
5								
6	TRANSFORMERS - OH - DEMAND	D	AP2D	0	8,374,112	2,319	112,263	40,023
7	TRANSFORMERS - OH - ENERGY	E	AP2E	0	5,580,777	2,139	117,166	24,178
8	TRANSFORMERS - UG - DEMAND	D	AP2D	0	4,947,640	1,370	66,328	23,647
9	TRANSFORMERS - UG - ENERGY	E	AP2E	0	3,297,266	1,264	69,225	14,285
10								
11	OH LINES DEMAND	D	AP2D	0	15,046,457	4,167	201,713	71,913
12	OH LINES ENERGY	E	AP2E	0	10,027,442	3,843	210,523	43,442
13	UG LINES DEMAND	D	AP2D	0	722,629	200	9,688	3,454
14	UG LINES ENERGY	E	AP2E	0	481,583	185	10,111	2,086
15								
16	SERVICES - OH - DEMAND	C	C02	247,297	1,884,002	522	25,257	5,447
17	SERVICES - OH - ENERGY	C	E02	284,337	1,177,500	451	24,721	8,433
18	SERVICES - UG - DEMAND	C	C02	635,226	4,839,398	1,340	64,877	13,991
19	SERVICES - UG - ENERGY	C	E02	730,371	3,024,622	1,159	63,501	21,663
20								
21	METER & METER INSTALLATIONS	C	S01	76,740	5,753,747	9,263	203,082	87,584
22	INSTALL. ON CUSTR PREMISES	C	C03	582,742	0	0	0	0
23	STREET LIGHTING	C	C04	0	0	0	0	0
24	CUSTOMER ACCOUNTING	C	S02	1	896	0	25	19
25	UNCOLLECTIBLES	R	S03	0	0	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	E01	44	144	0	3	1
27	REVENUES	R	R99	0	0	0	0	0
28				-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		8,613,150	93,371,781	25,858	1,251,743	324,872
30	TOTAL ENERGY	E		9,937,270	59,439,465	22,779	1,247,911	370,850
31	TOTAL CUSTOMER	C		2,556,712	16,680,165	12,736	381,462	137,136
32	TOTAL REVENUE	R		0	0	0	0	0
33				-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL			21,107,132	169,491,411	61,372	2,881,116	832,858
				===========	===========	===========	===========	===========

				C&I SC2 SEC GEN SERV (11)	C&I SC2 SEC SPACE HTG (12)	C&I SC2 PRIMARY GEN (13)	SC4 MUNI STR LTG (14)	SC6 DUSK TO DAWN (15)	SC6 ENERGY LTG (16)
	PLANT IN SERVICE								
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	3,464,348	170,775	476,930	48,411	26,001	15,227
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	2,901,910	157,452	490,065	36,959	19,548	12,283
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	29,058,315	1,432,432	4,000,398	406,065	218,094	127,724
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	24,702,245	1,340,300	4,171,636	314,612	166,402	104,555
5									
6	TRANSFORMERS - OH - DEMAND	D	AP2D	4,236,845	208,856	0	59,206	31,799	18,623
7	TRANSFORMERS - OH - ENERGY	E	AP2E	3,846,291	208,693	0	48,987	25,910	16,280
8	TRANSFORMERS - UG - DEMAND	D	AP2D	2,503,237	123,397	0	34,981	18,788	11,003
9	TRANSFORMERS - UG - ENERGY	E	AP2E	2,272,487	123,301	0	28,943	15,308	9,619
10									
11	OH LINES DEMAND	D	AP2D	7,612,690	375,268	0	106,381	57,136	33,461
12	OH LINES ENERGY	E	AP2E	6,910,949	374,976	0	88,019	46,554	29,251
13	UG LINES DEMAND	D	AP2D	365,611	18,023	0	5,109	2,744	1,607
14	UG LINES ENERGY	E	AP2E	331,909	18,009	0	4,227	2,236	1,405
15									
16	SERVICES - OH - DEMAND	C	C02	953,202	46,988	131,225	0	0	4,190
17	SERVICES - OH - ENERGY	C	E02	811,537	44,033	137,050	0	0	0
18	SERVICES - UG - DEMAND	C	C02	2,448,473	120,698	337,076	0	0	10,762
19	SERVICES - UG - ENERGY	C	E02	2,084,580	113,106	352,037	0	0	0
20									
21	METER & METER INSTALLATIONS	C	S01	2,818,176	53,893	76,555	0	0	20,462
22	INSTALL. ON CUSTR PREMISES	C	C03	0	0	0	0	0	0
23	STREET LIGHTING	C	C04	0	0	0	3,033,914	1,630,192	0
24	CUSTOMER ACCOUNTING	C	S02	104	2	1	0	8	1
25	UNCOLLECTIBLES	R	S03	0	0	0	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	E01	99	5	17	1	1	0
27	REVENUES	R	R99	0	0	0	0	0	0
28				------------------	------------------	------------------	------------------	------------------	------------------
29	TOTAL DEMAND	D		47,241,045	2,328,751	4,477,328	660,152	354,562	207,644
30	TOTAL ENERGY	E		40,965,891	2,222,737	4,661,719	521,748	275,960	173,393
31	TOTAL CUSTOMER	C		9,116,073	378,719	1,033,944	3,033,914	1,630,200	35,415
32	TOTAL REVENUE	R		0	0	0	0	0	0
33				------------------	------------------	------------------	------------------	------------------	------------------
34	TOTAL			97,323,009	4,930,207	10,172,991	4,215,815	2,260,722	416,452
				===========	===========	===========	===========	===========	===========

				SC7 PRIMARY T.O.U. (17)	SC7 SEP MET SP HTG (18)	SC7 HV TOD (19)
	PLANT IN SERVICE					
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	838,362	60,421	175,545
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	984,922	31,815	265,606
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	7,032,025	506,797	0
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	8,384,064	270,819	0
5						
6	TRANSFORMERS - OH - DEMAND	D	AP2D	0	0	0
7	TRANSFORMERS - OH - ENERGY	E	AP2E	0	0	0
8	TRANSFORMERS - UG - DEMAND	D	AP2D	0	0	0
9	TRANSFORMERS - UG - ENERGY	E	AP2E	0	0	0
10						
11	OH LINES DEMAND	D	AP2D	0	0	0
12	OH LINES ENERGY	E	AP2E	0	0	0
13	UG LINES DEMAND	D	AP2D	0	0	0
14	UG LINES ENERGY	E	AP2E	0	0	0
15						
16	SERVICES - OH - DEMAND	C	C02	230,672	16,625	0
17	SERVICES - OH - ENERGY	C	E02	275,440	8,897	0
18	SERVICES - UG - DEMAND	C	C02	592,523	42,703	0
19	SERVICES - UG - ENERGY	C	E02	707,517	22,854	0
20						
21	METER & METER INSTALLATIONS	C	S01	42,930	20,285	13,524
22	INSTALL. ON CUSTR PREMISES	C	C03	441,587	141,155	0
23	STREET LIGHTING	C	C04	0	0	0
24	CUSTOMER ACCOUNTING	C	S02	1	0	0
25	UNCOLLECTIBLES	R	S03	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	E01	34	1	9
27	REVENUES	R	R99	0	0	0
28				-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		7,870,387	567,218	175,545
30	TOTAL ENERGY	E		9,369,020	302,635	265,615
31	TOTAL CUSTOMER	C		2,290,670	252,519	13,524
32	TOTAL REVENUE	R		0	0	0
33				-------------------	-------------------	-------------------
34	TOTAL			19,530,077	1,122,372	454,683
				===========	===========	===========

				TOTAL COMPANY (1)	TOTAL RESIDENTIAL (2)	TOTAL C&I (3)	MUNICIPAL LIGHTING (4)	PRIVATE LIGHTING (5)
	GENERAL PLANT							
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	174,846	99,177	59,038	692	589
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	131,902	61,449	51,147	528	455
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	1,561,151	898,407	534,808	6,266	5,336
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	1,177,710	564,910	470,207	4,855	4,181
5								
6	TRANSFORMERS - OH - DEMAND	D	AP2D	48,157	31,244	16,510	218	186
7	TRANSFORMERS - OH - ENERGY	E	AP2E	36,329	20,980	15,014	180	155
8	TRANSFORMERS - UG - DEMAND	D	AP2D	28,453	18,460	9,755	129	110
9	TRANSFORMERS - UG - ENERGY	E	AP2E	21,464	12,395	8,871	107	92
10								
11	OH LINES DEMAND	D	AP2D	857,621	556,409	294,026	3,881	3,305
12	OH LINES ENERGY	E	AP2E	646,977	373,624	267,377	3,211	2,765
13	UG LINES DEMAND	D	AP2D	6,252	4,056	2,143	28	24
14	UG LINES ENERGY	E	AP2E	4,716	2,724	1,949	23	20
15								
16	SERVICES - OH - DEMAND	C	C02	117,364	67,959	40,455	0	149
17	SERVICES - OH - ENERGY	C	E02	88,538	42,797	35,622	0	0
18	SERVICES - UG - DEMAND	C	C02	39,735	23,009	13,697	0	50
19	SERVICES - UG - ENERGY	C	E02	29,976	14,490	12,060	0	0
20								
21	METER & METER INSTALLATIONS	C	S01	104,898	68,776	35,001	0	236
22	INSTALL. ON CUSTR PREMISES	C	C03	2,145	0	0	0	0
23	STREET LIGHTING	C	C04	98,285	0	0	63,933	34,353
24	CUSTOMER ACCOUNTING	C	S02	1,439,719	1,253,141	172,649	410	12,674
25	UNCOLLECTIBLES	R	S03	0	0	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	E01	430,297	200,461	166,855	1,723	1,484
27	REVENUES	R	R99	0	0	0	0	0
28				-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		2,676,480	1,607,751	916,280	11,214	9,550
30	TOTAL ENERGY	E		2,449,396	1,236,543	981,420	10,627	9,152
31	TOTAL CUSTOMER	C		1,920,658	1,470,172	309,484	64,342	47,462
32	TOTAL REVENUE	R		0	0	0	0	0
33				-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL			7,046,534	4,314,466	2,207,185	86,183	66,165
				===========	===========	===========	===========	===========

				TOTAL PRIMARY (6)	RESID SC1 GENERAL (7)	RESID SC3 T.O.U. (8)	RESID SC5 W/ SP HTG (9)	C&I SC2 SEC NON DEM (10)
	GENERAL PLANT							
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	15,351	97,838	27	1,312	283
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	18,323	60,162	23	1,263	431
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	116,334	886,280	245	11,881	2,562
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	133,557	553,087	212	11,612	3,961
5								
6	TRANSFORMERS - OH - DEMAND	D	AP2D	0	30,822	9	413	147
7	TRANSFORMERS - OH - ENERGY	E	AP2E	0	20,541	8	431	89
8	TRANSFORMERS - UG - DEMAND	D	AP2D	0	18,210	5	244	87
9	TRANSFORMERS - UG - ENERGY	E	AP2E	0	12,136	5	255	53
10								
11	OH LINES DEMAND	D	AP2D	0	548,898	152	7,359	2,623
12	OH LINES ENERGY	E	AP2E	0	365,803	140	7,680	1,585
13	UG LINES DEMAND	D	AP2D	0	4,001	1	54	19
14	UG LINES ENERGY	E	AP2E	0	2,667	1	56	12
15								
16	SERVICES - OH - DEMAND	C	C02	8,800	67,042	19	899	194
17	SERVICES - OH - ENERGY	C	E02	10,118	41,901	16	880	300
18	SERVICES - UG - DEMAND	C	C02	2,979	22,698	6	304	66
19	SERVICES - UG - ENERGY	C	E02	3,426	14,186	5	298	102
20								
21	METER & METER INSTALLATIONS	C	S01	885	66,328	107	2,341	1,010
22	INSTALL. ON CUSTR PREMISES	C	C03	2,145	0	0	0	0
23	STREET LIGHTING	C	C04	0	0	0	0	0
24	CUSTOMER ACCOUNTING	C	S02	845	1,219,306	341	33,493	26,439
25	UNCOLLECTIBLES	R	S03	0	0	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	E01	59,774	196,266	75	4,121	1,406
27	REVENUES	R	R99	0	0	0	0	0
28				-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		131,685	1,586,050	439	21,263	5,722
30	TOTAL ENERGY	E		211,653	1,210,661	464	25,417	7,536
31	TOTAL CUSTOMER	C		29,198	1,431,462	494	38,215	28,109
32	TOTAL REVENUE	R		0	0	0	0	0
33				-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL			372,536	4,228,173	1,398	84,895	41,367
				===========	===========	===========	===========	===========

				C&I SC2 SEC GEN SERV (11)	C&I SC2 SEC SPACE HTG (12)	C&I SC2 PRIMARY GEN (13)	SC4 MUNI STR LTG (14)	SC6 DUSK TO DAWN (15)	SC6 ENERGY LTG (16)
	GENERAL PLANT								
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	49,501	2,440	6,815	692	372	218
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	41,464	2,250	7,002	528	279	176
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	448,409	22,104	61,732	6,266	3,365	1,971
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	381,189	20,683	64,374	4,855	2,568	1,613
5									
6	TRANSFORMERS - OH - DEMAND	D	AP2D	15,594	769	0	218	117	69
7	TRANSFORMERS - OH - ENERGY	E	AP2E	14,157	768	0	180	95	60
8	TRANSFORMERS - UG - DEMAND	D	AP2D	9,213	454	0	129	69	40
9	TRANSFORMERS - UG - ENERGY	E	AP2E	8,364	454	0	107	56	35
10									
11	OH LINES DEMAND	D	AP2D	277,713	13,690	0	3,881	2,084	1,221
12	OH LINES ENERGY	E	AP2E	252,113	13,679	0	3,211	1,698	1,067
13	UG LINES DEMAND	D	AP2D	2,024	100	0	28	15	9
14	UG LINES ENERGY	E	AP2E	1,838	100	0	23	12	8
15									
16	SERVICES - OH - DEMAND	C	C02	33,920	1,672	4,670	0	0	149
17	SERVICES - OH - ENERGY	C	E02	28,879	1,567	4,877	0	0	0
18	SERVICES - UG - DEMAND	C	C02	11,484	566	1,581	0	0	50
19	SERVICES - UG - ENERGY	C	E02	9,777	530	1,651	0	0	0
20									
21	METER & METER INSTALLATIONS	C	S01	32,487	621	883	0	0	236
22	INSTALL. ON CUSTR PREMISES	C	C03	0	0	0	0	0	0
23	STREET LIGHTING	C	C04	0	0	0	63,933	34,353	0
24	CUSTOMER ACCOUNTING	C	S02	141,491	3,215	1,505	410	10,681	1,993
25	UNCOLLECTIBLES	R	S03	0	0	0	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	E01	135,267	7,339	22,843	1,723	911	573
27	REVENUES	R	R99	0	0	0	0	0	0
28				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		802,455	39,557	68,546	11,214	6,023	3,527
30	TOTAL ENERGY	E		834,392	45,273	94,220	10,627	5,621	3,532
31	TOTAL CUSTOMER	C		258,037	8,171	15,166	64,342	45,034	2,429
32	TOTAL REVENUE	R		0	0	0	0	0	0
33				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL			1,894,884	93,001	177,932	86,183	56,677	9,488
				===========	===========	===========	===========	===========	===========

				SC7 PRIMARY T.O.U. (17)	SC7 SEP MET SP HTG (18)	SC7 HV TOD (19)
	GENERAL PLANT					
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	11,979	863	2,508
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	14,073	455	3,795
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	108,514	7,821	0
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	129,378	4,179	0
5						
6	TRANSFORMERS - OH - DEMAND	D	AP2D	0	0	0
7	TRANSFORMERS - OH - ENERGY	E	AP2E	0	0	0
8	TRANSFORMERS - UG - DEMAND	D	AP2D	0	0	0
9	TRANSFORMERS - UG - ENERGY	E	AP2E	0	0	0
10						
11	OH LINES DEMAND	D	AP2D	0	0	0
12	OH LINES ENERGY	E	AP2E	0	0	0
13	UG LINES DEMAND	D	AP2D	0	0	0
14	UG LINES ENERGY	E	AP2E	0	0	0
15						
16	SERVICES - OH - DEMAND	C	C02	8,208	592	0
17	SERVICES - OH - ENERGY	C	E02	9,802	317	0
18	SERVICES - UG - DEMAND	C	C02	2,779	200	0
19	SERVICES - UG - ENERGY	C	E02	3,318	107	0
20						
21	METER & METER INSTALLATIONS	C	S01	495	234	156
22	INSTALL. ON CUSTR PREMISES	C	C03	1,625	520	0
23	STREET LIGHTING	C	C04	0	0	0
24	CUSTOMER ACCOUNTING	C	S02	761	60	24
25	UNCOLLECTIBLES	R	S03	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	E01	45,910	1,483	12,381
27	REVENUES	R	R99	0	0	0
28				-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		120,493	8,684	2,508
30	TOTAL ENERGY	E		189,361	6,117	16,176
31	TOTAL CUSTOMER	C		26,989	2,029	180
32	TOTAL REVENUE	R		0	0	0
33				-------------------	-------------------	-------------------
34	TOTAL			336,843	16,829	18,864
				===========	===========	===========

				TOTAL COMPANY (1)	TOTAL RESIDENTIAL (2)	TOTAL C&I (3)	MUNICIPAL LIGHTING (4)	PRIVATE LIGHTING (5)
	PLANT HELD FOR FUTURE USE							
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	0	0	0	0	0
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	0	0	0	0	0
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	118,964	68,461	40,754	477	407
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	89,745	43,048	35,831	370	319
5								
6	TRANSFORMERS - OH - DEMAND	D	AP2D	0	0	0	0	0
7	TRANSFORMERS - OH - ENERGY	E	AP2E	0	0	0	0	0
8	TRANSFORMERS - UG - DEMAND	D	AP2D	0	0	0	0	0
9	TRANSFORMERS - UG - ENERGY	E	AP2E	0	0	0	0	0
10								
11	OH LINES DEMAND	D	AP2D	0	0	0	0	0
12	OH LINES ENERGY	E	AP2E	0	0	0	0	0
13	UG LINES DEMAND	D	AP2D	0	0	0	0	0
14	UG LINES ENERGY	E	AP2E	0	0	0	0	0
15								
16	SERVICES - OH - DEMAND	C	C02	0	0	0	0	0
17	SERVICES - OH - ENERGY	C	E02	0	0	0	0	0
18	SERVICES - UG - DEMAND	C	C02	0	0	0	0	0
19	SERVICES - UG - ENERGY	C	E02	0	0	0	0	0
20								
21	METER & METER INSTALLATIONS	C	S01	0	0	0	0	0
22	INSTALL. ON CUSTR PREMISES	C	C03	0	0	0	0	0
23	STREET LIGHTING	C	C04	0	0	0	0	0
24	CUSTOMER ACCOUNTING	C	S02	0	0	0	0	0
25	UNCOLLECTIBLES	R	S03	0	0	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	E01	0	0	0	0	0
27	REVENUES	R	R99	0	0	0	0	0
28				-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		118,964	68,461	40,754	477	407
30	TOTAL ENERGY	E		89,745	43,048	35,831	370	319
31	TOTAL CUSTOMER	C		0	0	0	0	0
32	TOTAL REVENUE	R		0	0	0	0	0
33				-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL			208,709	111,509	76,585	847	725
				=============	============	===========	===========	===========

				TOTAL PRIMARY (6)	RESID SC1 GENERAL (7)	RESID SC3 T.O.U. (8)	RESID SC5 W/ SP HTG (9)	C&I SC2 SEC NON DEM (10)
	PLANT HELD FOR FUTURE USE							
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	0	0	0	0	0
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	0	0	0	0	0
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	8,865	67,537	19	905	195
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	10,177	42,147	16	885	302
5								
6	TRANSFORMERS - OH - DEMAND	D	AP2D	0	0	0	0	0
7	TRANSFORMERS - OH - ENERGY	E	AP2E	0	0	0	0	0
8	TRANSFORMERS - UG - DEMAND	D	AP2D	0	0	0	0	0
9	TRANSFORMERS - UG - ENERGY	E	AP2E	0	0	0	0	0
10								
11	OH LINES DEMAND	D	AP2D	0	0	0	0	0
12	OH LINES ENERGY	E	AP2E	0	0	0	0	0
13	UG LINES DEMAND	D	AP2D	0	0	0	0	0
14	UG LINES ENERGY	E	AP2E	0	0	0	0	0
15								
16	SERVICES - OH - DEMAND	C	C02	0	0	0	0	0
17	SERVICES - OH - ENERGY	C	E02	0	0	0	0	0
18	SERVICES - UG - DEMAND	C	C02	0	0	0	0	0
19	SERVICES - UG - ENERGY	C	E02	0	0	0	0	0
20								
21	METER & METER INSTALLATIONS	C	S01	0	0	0	0	0
22	INSTALL. ON CUSTR PREMISES	C	C03	0	0	0	0	0
23	STREET LIGHTING	C	C04	0	0	0	0	0
24	CUSTOMER ACCOUNTING	C	S02	0	0	0	0	0
25	UNCOLLECTIBLES	R	S03	0	0	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	E01	0	0	0	0	0
27	REVENUES	R	R99	0	0	0	0	0
28				-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		8,865	67,537	19	905	195
30	TOTAL ENERGY	E		10,177	42,147	16	885	302
31	TOTAL CUSTOMER	C		0	0	0	0	0
32	TOTAL REVENUE	R		0	0	0	0	0
33				-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL			19,042	109,684	35	1,790	497
				===========	===========	===========	===========	===========

				C&I SC2 SEC GEN SERV (11)	C&I SC2 SEC SPACE HTG (12)	C&I SC2 PRIMARY GEN (13)	SC4 MUNI STR LTG (14)	SC6 DUSK TO DAWN (15)	SC6 ENERGY LTG (16)
	PLANT HELD FOR FUTURE USE								
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	0	0	0	0	0	0
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	0	0	0	0	0	0
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	34,170	1,684	4,704	477	256	150
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	29,048	1,576	4,905	370	196	123
5									
6	TRANSFORMERS - OH - DEMAND	D	AP2D	0	0	0	0	0	0
7	TRANSFORMERS - OH - ENERGY	E	AP2E	0	0	0	0	0	0
8	TRANSFORMERS - UG - DEMAND	D	AP2D	0	0	0	0	0	0
9	TRANSFORMERS - UG - ENERGY	E	AP2E	0	0	0	0	0	0
10									
11	OH LINES DEMAND	D	AP2D	0	0	0	0	0	0
12	OH LINES ENERGY	E	AP2E	0	0	0	0	0	0
13	UG LINES DEMAND	D	AP2D	0	0	0	0	0	0
14	UG LINES ENERGY	E	AP2E	0	0	0	0	0	0
15									
16	SERVICES - OH - DEMAND	C	C02	0	0	0	0	0	0
17	SERVICES - OH - ENERGY	C	E02	0	0	0	0	0	0
18	SERVICES - UG - DEMAND	C	C02	0	0	0	0	0	0
19	SERVICES - UG - ENERGY	C	E02	0	0	0	0	0	0
20									
21	METER & METER INSTALLATIONS	C	S01	0	0	0	0	0	0
22	INSTALL. ON CUSTR PREMISES	C	C03	0	0	0	0	0	0
23	STREET LIGHTING	C	C04	0	0	0	0	0	0
24	CUSTOMER ACCOUNTING	C	S02	0	0	0	0	0	0
25	UNCOLLECTIBLES	R	S03	0	0	0	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	E01	0	0	0	0	0	0
27	REVENUES	R	R99	0	0	0	0	0	0
28				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		34,170	1,684	4,704	477	256	150
30	TOTAL ENERGY	E		29,048	1,576	4,905	370	196	123
31	TOTAL CUSTOMER	C		0	0	0	0	0	0
32	TOTAL REVENUE	R		0	0	0	0	0	0
33				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL			63,218	3,260	9,610	847	452	273
				===========	===========	===========	===========	===========	===========

				SC7 PRIMARY T.O.U. (17)	SC7 SEP MET SP HTG (18)	SC7 HV TOD (19)
	PLANT HELD FOR FUTURE USE					
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	0	0	0
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	0	0	0
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	8,269	596	0
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	9,859	318	0
5						
6	TRANSFORMERS - OH - DEMAND	D	AP2D	0	0	0
7	TRANSFORMERS - OH - ENERGY	E	AP2E	0	0	0
8	TRANSFORMERS - UG - DEMAND	D	AP2D	0	0	0
9	TRANSFORMERS - UG - ENERGY	E	AP2E	0	0	0
10						
11	OH LINES DEMAND	D	AP2D	0	0	0
12	OH LINES ENERGY	E	AP2E	0	0	0
13	UG LINES DEMAND	D	AP2D	0	0	0
14	UG LINES ENERGY	E	AP2E	0	0	0
15						
16	SERVICES - OH - DEMAND	C	C02	0	0	0
17	SERVICES - OH - ENERGY	C	E02	0	0	0
18	SERVICES - UG - DEMAND	C	C02	0	0	0
19	SERVICES - UG - ENERGY	C	E02	0	0	0
20						
21	METER & METER INSTALLATIONS	C	S01	0	0	0
22	INSTALL. ON CUSTR PREMISES	C	C03	0	0	0
23	STREET LIGHTING	C	C04	0	0	0
24	CUSTOMER ACCOUNTING	C	S02	0	0	0
25	UNCOLLECTIBLES	R	S03	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	E01	0	0	0
27	REVENUES	R	R99	0	0	0
28				-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		8,269	596	0
30	TOTAL ENERGY	E		9,859	318	0
31	TOTAL CUSTOMER	C		0	0	0
32	TOTAL REVENUE	R		0	0	0
33				-------------------	-------------------	-------------------
34	TOTAL			18,128	914	0
				===========	===========	===========

				TOTAL COMPANY (1)	TOTAL RESIDENTIAL (2)	TOTAL C&I (3)	MUNICIPAL LIGHTING (4)	PRIVATE LIGHTING (5)
	ACCUM. PROV. FOR DEPRECIATION							
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	3,065,679	1,738,919	1,035,152	12,128	10,329
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	2,312,706	1,077,413	896,793	9,259	7,975
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	22,529,663	12,965,305	7,718,045	90,429	77,012
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	16,996,062	8,152,473	6,785,769	70,063	60,341
5								
6	TRANSFORMERS - OH - DEMAND	D	AP2D	3,332,533	2,162,087	1,142,523	15,080	12,843
7	TRANSFORMERS - OH - ENERGY	E	AP2E	2,514,016	1,451,822	1,038,971	12,477	10,746
8	TRANSFORMERS - UG - DEMAND	D	AP2D	1,968,946	1,277,417	675,032	8,910	7,588
9	TRANSFORMERS - UG - ENERGY	E	AP2E	1,485,345	857,774	613,850	7,372	6,349
10								
11	OH LINES DEMAND	D	AP2D	5,347,129	3,469,122	1,833,206	24,196	20,606
12	OH LINES ENERGY	E	AP2E	4,033,799	2,329,484	1,667,054	20,020	17,242
13	UG LINES DEMAND	D	AP2D	283,331	183,820	97,137	1,282	1,092
14	UG LINES ENERGY	E	AP2E	213,741	123,433	88,333	1,061	914
15								
16	SERVICES - OH - DEMAND	C	C02	1,293,098	748,768	445,730	0	1,643
17	SERVICES - OH - ENERGY	C	E02	975,495	471,532	392,483	0	0
18	SERVICES - UG - DEMAND	C	C02	3,242,392	1,877,506	1,117,650	0	4,119
19	SERVICES - UG - ENERGY	C	E02	2,446,015	1,182,348	984,135	0	0
20								
21	METER & METER INSTALLATIONS	C	S01	1,045,604	685,551	348,884	0	2,351
22	INSTALL. ON CUSTR PREMISES	C	C03	190,467	0	0	0	0
23	STREET LIGHTING	C	C04	1,922,277	0	0	1,250,405	671,872
24	CUSTOMER ACCOUNTING	C	S02	435,856	379,372	52,267	124	3,837
25	UNCOLLECTIBLES	R	S03	0	0	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	E01	130,267	60,687	50,513	522	449
27	REVENUES	R	R99	0	0	0	0	0
28				-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		36,527,281	21,796,669	12,501,094	152,026	129,470
30	TOTAL ENERGY	E		27,685,935	14,053,087	11,141,283	120,773	104,015
31	TOTAL CUSTOMER	C		11,551,203	5,345,076	3,341,149	1,250,529	683,821
32	TOTAL REVENUE	R		0	0	0	0	0
33				-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL			75,764,419	41,194,832	26,983,526	1,523,328	917,306
				===========	===========	===========	===========	===========

				TOTAL PRIMARY (6)	RESID SC1 GENERAL (7)	RESID SC3 T.O.U. (8)	RESID SC5 W/ SP HTG (9)	C&I SC2 SEC NON DEM (10)
	ACCUM. PROV. FOR DEPRECIATION							
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	269,151	1,715,447	475	22,997	4,959
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	321,265	1,054,863	404	22,146	7,555
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	1,678,872	12,790,296	3,542	171,467	36,977
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	1,927,415	7,981,839	3,059	167,576	57,167
5								
6	TRANSFORMERS - OH - DEMAND	D	AP2D	0	2,132,903	591	28,594	10,194
7	TRANSFORMERS - OH - ENERGY	E	AP2E	0	1,421,435	545	29,843	6,158
8	TRANSFORMERS - UG - DEMAND	D	AP2D	0	1,260,174	349	16,894	6,023
9	TRANSFORMERS - UG - ENERGY	E	AP2E	0	839,820	322	17,632	3,638
10								
11	OH LINES DEMAND	D	AP2D	0	3,422,294	948	45,879	16,356
12	OH LINES ENERGY	E	AP2E	0	2,280,727	874	47,883	9,881
13	UG LINES DEMAND	D	AP2D	0	181,339	50	2,431	867
14	UG LINES ENERGY	E	AP2E	0	120,850	46	2,537	524
15								
16	SERVICES - OH - DEMAND	C	C02	96,958	738,661	205	9,902	2,135
17	SERVICES - OH - ENERGY	C	E02	111,480	461,663	177	9,692	3,306
18	SERVICES - UG - DEMAND	C	C02	243,117	1,852,162	513	24,830	5,355
19	SERVICES - UG - ENERGY	C	E02	279,532	1,157,601	444	24,303	8,291
20								
21	METER & METER INSTALLATIONS	C	S01	8,818	661,151	1,064	23,336	10,064
22	INSTALL. ON CUSTR PREMISES	C	C03	190,467	0	0	0	0
23	STREET LIGHTING	C	C04	0	0	0	0	0
24	CUSTOMER ACCOUNTING	C	S02	256	369,129	103	10,140	8,004
25	UNCOLLECTIBLES	R	S03	0	0	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	E01	18,096	59,417	23	1,247	426
27	REVENUES	R	R99	0	0	0	0	0
28				-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		1,948,023	21,502,452	5,955	288,262	75,376
30	TOTAL ENERGY	E		2,266,776	13,758,950	5,273	288,864	85,348
31	TOTAL CUSTOMER	C		930,627	5,240,366	2,506	102,204	37,155
32	TOTAL REVENUE	R		0	0	0	0	0
33				-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL			5,145,426	40,501,768	13,733	679,330	197,880
				===========	===========	===========	===========	===========

				C&I SC2 SEC GEN SERV (11)	C&I SC2 SEC SPACE HTG (12)	C&I SC2 PRIMARY GEN (13)	SC4 MUNI STR LTG (14)	SC6 DUSK TO DAWN (15)	SC6 ENERGY LTG (16)
	ACCUM. PROV. FOR DEPRECIATION								
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	867,923	42,784	119,485	12,128	6,514	3,815
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	727,015	39,447	122,776	9,259	4,897	3,077
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	6,471,194	318,998	890,876	90,429	48,569	28,444
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	5,501,112	298,481	929,010	70,063	37,057	23,284
5									
6	TRANSFORMERS - OH - DEMAND	D	AP2D	1,079,133	53,196	0	15,080	8,099	4,743
7	TRANSFORMERS - OH - ENERGY	E	AP2E	979,658	53,155	0	12,477	6,599	4,147
8	TRANSFORMERS - UG - DEMAND	D	AP2D	637,579	31,430	0	8,910	4,785	2,802
9	TRANSFORMERS - UG - ENERGY	E	AP2E	578,807	31,405	0	7,372	3,899	2,450
10									
11	OH LINES DEMAND	D	AP2D	1,731,495	85,354	0	24,196	12,996	7,611
12	OH LINES ENERGY	E	AP2E	1,571,885	85,288	0	20,020	10,589	6,653
13	UG LINES DEMAND	D	AP2D	91,747	4,523	0	1,282	689	403
14	UG LINES ENERGY	E	AP2E	83,290	4,519	0	1,061	561	353
15									
16	SERVICES - OH - DEMAND	C	C02	373,722	18,423	51,450	0	0	1,643
17	SERVICES - OH - ENERGY	C	E02	318,179	17,264	53,733	0	0	0
18	SERVICES - UG - DEMAND	C	C02	937,094	46,194	129,008	0	0	4,119
19	SERVICES - UG - ENERGY	C	E02	797,822	43,288	134,734	0	0	0
20									
21	METER & METER INSTALLATIONS	C	S01	323,831	6,193	8,797	0	0	2,351
22	INSTALL. ON CUSTR PREMISES	C	C03	0	0	0	0	0	0
23	STREET LIGHTING	C	C04	0	0	0	1,250,405	671,872	0
24	CUSTOMER ACCOUNTING	C	S02	42,834	973	456	124	3,234	603
25	UNCOLLECTIBLES	R	S03	0	0	0	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	E01	40,950	2,222	6,916	522	276	173
27	REVENUES	R	R99	0	0	0	0	0	0
28				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		10,879,072	536,285	1,010,361	152,026	81,652	47,818
30	TOTAL ENERGY	E		9,482,717	514,516	1,058,702	120,773	63,879	40,137
31	TOTAL CUSTOMER	C		2,793,483	132,335	378,176	1,250,529	675,105	8,716
32	TOTAL REVENUE	R		0	0	0	0	0	0
33				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL			23,155,272	1,183,135	2,447,239	1,523,328	820,635	96,671
				===========	===========	===========	===========	===========	===========

				SC7 PRIMARY T.O.U. (17)	SC7 SEP MET SP HTG (18)	SC7 HV TOD (19)
	ACCUM. PROV. FOR DEPRECIATION					
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	210,035	15,137	43,979
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	246,753	7,971	66,542
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	1,566,010	112,862	0
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	1,867,104	60,311	0
5						
6	TRANSFORMERS - OH - DEMAND	D	AP2D	0	0	0
7	TRANSFORMERS - OH - ENERGY	E	AP2E	0	0	0
8	TRANSFORMERS - UG - DEMAND	D	AP2D	0	0	0
9	TRANSFORMERS - UG - ENERGY	E	AP2E	0	0	0
10						
11	OH LINES DEMAND	D	AP2D	0	0	0
12	OH LINES ENERGY	E	AP2E	0	0	0
13	UG LINES DEMAND	D	AP2D	0	0	0
14	UG LINES ENERGY	E	AP2E	0	0	0
15						
16	SERVICES - OH - DEMAND	C	C02	90,440	6,518	0
17	SERVICES - OH - ENERGY	C	E02	107,992	3,488	0
18	SERVICES - UG - DEMAND	C	C02	226,774	16,344	0
19	SERVICES - UG - ENERGY	C	E02	270,785	8,747	0
20						
21	METER & METER INSTALLATIONS	C	S01	4,933	2,331	1,554
22	INSTALL. ON CUSTR PREMISES	C	C03	144,331	46,136	0
23	STREET LIGHTING	C	C04	0	0	0
24	CUSTOMER ACCOUNTING	C	S02	231	18	7
25	UNCOLLECTIBLES	R	S03	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	E01	13,899	449	3,748
27	REVENUES	R	R99	0	0	0
28				-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		1,776,044	127,999	43,979
30	TOTAL ENERGY	E		2,127,756	68,730	70,290
31	TOTAL CUSTOMER	C		845,485	83,581	1,561
32	TOTAL REVENUE	R		0	0	0
33				-------------------	-------------------	-------------------
34	TOTAL			4,749,285	280,311	115,831
				===========	===========	===========

				TOTAL COMPANY (1)	TOTAL RESIDENTIAL (2)	TOTAL C&I (3)	MUNICIPAL LIGHTING (4)	PRIVATE LIGHTING (5)
	NON-INTEREST BEARING CWIP							
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	27,715	15,720	9,358	110	93
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	20,908	9,740	8,107	84	72
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	230,769	132,802	79,055	926	789
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	174,089	83,505	69,506	718	618
5								
6	TRANSFORMERS - OH - DEMAND	D	AP2D	27,669	17,951	9,486	125	107
7	TRANSFORMERS - OH - ENERGY	E	AP2E	20,873	12,054	8,626	104	89
8	TRANSFORMERS - UG - DEMAND	D	AP2D	16,347	10,606	5,604	74	63
9	TRANSFORMERS - UG - ENERGY	E	AP2E	12,332	7,122	5,097	61	53
10								
11	OH LINES DEMAND	D	AP2D	60,632	39,337	20,787	274	234
12	OH LINES ENERGY	E	AP2E	45,740	26,415	18,903	227	196
13	UG LINES DEMAND	D	AP2D	2,417	1,568	829	11	9
14	UG LINES ENERGY	E	AP2E	1,824	1,053	754	9	8
15								
16	SERVICES - OH - DEMAND	C	C02	8,464	4,901	2,918	0	11
17	SERVICES - OH - ENERGY	C	E02	6,385	3,087	2,569	0	0
18	SERVICES - UG - DEMAND	C	C02	18,036	10,444	6,217	0	23
19	SERVICES - UG - ENERGY	C	E02	13,606	6,577	5,474	0	0
20								
21	METER & METER INSTALLATIONS	C	S01	20,254	13,279	6,758	0	46
22	INSTALL. ON CUSTR PREMISES	C	C03	1,232	0	0	0	0
23	STREET LIGHTING	C	C04	11,012	0	0	7,163	3,849
24	CUSTOMER ACCOUNTING	C	S02	20,387	17,745	2,445	6	179
25	UNCOLLECTIBLES	R	S03	0	0	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	E01	6,093	2,839	2,363	24	21
27	REVENUES	R	R99	0	0	0	0	0
28				-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		365,549	217,985	125,119	1,520	1,295
30	TOTAL ENERGY	E		281,858	142,727	113,355	1,227	1,056
31	TOTAL CUSTOMER	C		99,377	56,033	26,381	7,169	4,107
32	TOTAL REVENUE	R		0	0	0	0	0
33				-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL			746,784	416,744	264,856	9,916	6,459
				===========	===========	===========	===========	===========

				TOTAL PRIMARY (6)	RESID SC1 GENERAL (7)	RESID SC3 T.O.U. (8)	RESID SC5 W/ SP HTG (9)	C&I SC2 SEC NON DEM (10)
	NON-INTEREST BEARING CWIP							
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	2,433	15,508	4	208	45
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	2,904	9,536	4	200	68
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	17,196	131,009	36	1,756	379
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	19,742	81,757	31	1,716	586
5								
6	TRANSFORMERS - OH - DEMAND	D	AP2D	0	17,709	5	237	85
7	TRANSFORMERS - OH - ENERGY	E	AP2E	0	11,802	5	248	51
8	TRANSFORMERS - UG - DEMAND	D	AP2D	0	10,463	3	140	50
9	TRANSFORMERS - UG - ENERGY	E	AP2E	0	6,973	3	146	30
10								
11	OH LINES DEMAND	D	AP2D	0	38,806	11	520	185
12	OH LINES ENERGY	E	AP2E	0	25,862	10	543	112
13	UG LINES DEMAND	D	AP2D	0	1,547	0	21	7
14	UG LINES ENERGY	E	AP2E	0	1,031	0	22	4
15								
16	SERVICES - OH - DEMAND	C	C02	635	4,835	1	65	14
17	SERVICES - OH - ENERGY	C	E02	730	3,022	1	63	22
18	SERVICES - UG - DEMAND	C	C02	1,352	10,303	3	138	30
19	SERVICES - UG - ENERGY	C	E02	1,555	6,439	2	135	46
20								
21	METER & METER INSTALLATIONS	C	S01	171	12,807	21	452	195
22	INSTALL. ON CUSTR PREMISES	C	C03	1,232	0	0	0	0
23	STREET LIGHTING	C	C04	0	0	0	0	0
24	CUSTOMER ACCOUNTING	C	S02	12	17,266	5	474	374
25	UNCOLLECTIBLES	R	S03	0	0	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	E01	846	2,779	1	58	20
27	REVENUES	R	R99	0	0	0	0	0
28				-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		19,630	215,042	60	2,883	751
30	TOTAL ENERGY	E		23,493	139,739	54	2,934	872
31	TOTAL CUSTOMER	C		5,687	54,672	33	1,328	681
32	TOTAL REVENUE	R		0	0	0	0	0
33				-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL			48,810	409,453	146	7,145	2,304
				===========	===========	===========	===========	===========

				C&I SC2 SEC GEN SERV (11)	C&I SC2 SEC SPACE HTG (12)	C&I SC2 PRIMARY GEN (13)	SC4 MUNI STR LTG (14)	SC6 DUSK TO DAWN (15)	SC6 ENERGY LTG (16)
	NON-INTEREST BEARING CWIP								
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	7,846	387	1,080	110	59	34
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	6,572	357	1,110	84	44	28
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	66,284	3,267	9,125	926	497	291
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	56,347	3,057	9,516	718	380	238
5									
6	TRANSFORMERS - OH - DEMAND	D	AP2D	8,960	442	0	125	67	39
7	TRANSFORMERS - OH - ENERGY	E	AP2E	8,134	441	0	104	55	34
8	TRANSFORMERS - UG - DEMAND	D	AP2D	5,294	261	0	74	40	23
9	TRANSFORMERS - UG - ENERGY	E	AP2E	4,806	261	0	61	32	20
10									
11	OH LINES DEMAND	D	AP2D	19,634	968	0	274	147	86
12	OH LINES ENERGY	E	AP2E	17,824	967	0	227	120	75
13	UG LINES DEMAND	D	AP2D	783	39	0	11	6	3
14	UG LINES ENERGY	E	AP2E	711	39	0	9	5	3
15									
16	SERVICES - OH - DEMAND	C	C02	2,446	121	337	0	0	11
17	SERVICES - OH - ENERGY	C	E02	2,083	113	352	0	0	0
18	SERVICES - UG - DEMAND	C	C02	5,213	257	718	0	0	23
19	SERVICES - UG - ENERGY	C	E02	4,438	241	749	0	0	0
20									
21	METER & METER INSTALLATIONS	C	S01	6,273	120	170	0	0	46
22	INSTALL. ON CUSTR PREMISES	C	C03	0	0	0	0	0	0
23	STREET LIGHTING	C	C04	0	0	0	7,163	3,849	0
24	CUSTOMER ACCOUNTING	C	S02	2,004	46	21	6	151	28
25	UNCOLLECTIBLES	R	S03	0	0	0	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	E01	1,915	104	323	24	13	8
27	REVENUES	R	R99	0	0	0	0	0	0
28				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		108,800	5,363	10,205	1,520	817	478
30	TOTAL ENERGY	E		96,309	5,226	10,949	1,227	649	408
31	TOTAL CUSTOMER	C		22,456	897	2,347	7,169	4,000	107
32	TOTAL REVENUE	R		0	0	0	0	0	0
33				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL			227,565	11,486	23,502	9,916	5,465	993
				===========	===========	===========	===========	===========	===========

				SC7 PRIMARY T.O.U. (17)	SC7 SEP MET SP HTG (18)	SC7 HV TOD (19)
	NON-INTEREST BEARING CWIP					
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	1,899	137	398
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	2,231	72	602
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	16,040	1,156	0
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	19,125	618	0
5						
6	TRANSFORMERS - OH - DEMAND	D	AP2D	0	0	0
7	TRANSFORMERS - OH - ENERGY	E	AP2E	0	0	0
8	TRANSFORMERS - UG - DEMAND	D	AP2D	0	0	0
9	TRANSFORMERS - UG - ENERGY	E	AP2E	0	0	0
10						
11	OH LINES DEMAND	D	AP2D	0	0	0
12	OH LINES ENERGY	E	AP2E	0	0	0
13	UG LINES DEMAND	D	AP2D	0	0	0
14	UG LINES ENERGY	E	AP2E	0	0	0
15						
16	SERVICES - OH - DEMAND	C	C02	592	43	0
17	SERVICES - OH - ENERGY	C	E02	707	23	0
18	SERVICES - UG - DEMAND	C	C02	1,261	91	0
19	SERVICES - UG - ENERGY	C	E02	1,506	49	0
20						
21	METER & METER INSTALLATIONS	C	S01	96	45	30
22	INSTALL. ON CUSTR PREMISES	C	C03	934	298	0
23	STREET LIGHTING	C	C04	0	0	0
24	CUSTOMER ACCOUNTING	C	S02	11	1	0
25	UNCOLLECTIBLES	R	S03	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	E01	650	21	175
27	REVENUES	R	R99	0	0	0
28				-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		17,939	1,293	398
30	TOTAL ENERGY	E		22,005	711	777
31	TOTAL CUSTOMER	C		5,107	550	30
32	TOTAL REVENUE	R		0	0	0
33				-------------------	-------------------	-------------------
34	TOTAL			45,051	2,553	1,205
				===========	===========	===========

			TOTAL COMPANY (1)	TOTAL RESIDENTIAL (2)	TOTAL C&I (3)	MUNICIPAL LIGHTING (4)	PRIVATE LIGHTING (5)
	NET PLANT						
1	HIGH TENSION ≥ 69 KV - DEMAND	D	9,373,661	5,316,942	3,165,093	37,084	31,582
2	HIGH TENSION ≥ 69 KV - ENERGY	E	7,071,358	3,294,314	2,742,045	28,312	24,383
3	HIGH TENSION < 69 KV - DEMAND	D	80,548,642	46,353,897	27,593,757	323,305	275,337
4	HIGH TENSION < 69 KV - ENERGY	E	60,764,765	29,146,936	24,260,659	250,491	215,734
5							
6	TRANSFORMERS - OH - DEMAND	D	9,827,340	6,375,801	3,369,197	44,469	37,872
7	TRANSFORMERS - OH - ENERGY	E	7,413,607	4,281,294	3,063,831	36,794	31,688
8	TRANSFORMERS - UG - DEMAND	D	5,806,244	3,766,987	1,990,608	26,274	22,375
9	TRANSFORMERS - UG - ENERGY	E	4,380,149	2,529,498	1,810,190	21,739	18,722
10							
11	OH LINES DEMAND	D	19,080,309	12,378,962	6,541,478	86,340	73,530
12	OH LINES ENERGY	E	14,393,917	8,312,362	5,948,593	71,437	61,525
13	UG LINES DEMAND	D	854,403	554,321	292,923	3,866	3,293
14	UG LINES ENERGY	E	644,549	372,222	266,374	3,199	2,755
15							
16	SERVICES - OH - DEMAND	C	2,130,860	1,233,873	734,506	0	2,707
17	SERVICES - OH - ENERGY	C	1,607,491	777,024	646,762	0	0
18	SERVICES - UG - DEMAND	C	5,287,221	3,061,563	1,822,501	0	6,717
19	SERVICES - UG - ENERGY	C	3,988,605	1,928,000	1,604,785	0	0
20							
21	METER & METER INSTALLATIONS	C	8,179,047	5,362,596	2,729,082	0	18,392
22	INSTALL. ON CUSTR PREMISES	C	395,653	0	0	0	0
23	STREET LIGHTING	C	2,851,126	0	0	1,854,605	996,522
24	CUSTOMER ACCOUNTING	C	1,025,308	892,435	122,953	292	9,026
25	UNCOLLECTIBLES	R	0	0	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	306,440	142,760	118,827	1,227	1,057
27	REVENUES	R	0	0	0	0	0
28			------------------	------------------	------------------	------------------	------------------
29	TOTAL DEMAND	D	125,490,598	74,746,909	42,953,055	521,338	443,988
30	TOTAL ENERGY	E	94,974,786	48,079,385	38,210,520	413,198	355,864
31	TOTAL CUSTOMER	C	25,465,310	13,255,492	7,660,589	1,854,896	1,033,363
32	TOTAL REVENUE	R	0	0	0	0	0
33			------------------	------------------	------------------	------------------	------------------
34	TOTAL		245,930,694	136,081,786	88,824,165	2,789,433	1,833,216
			===========	===========	===========	===========	===========

			TOTAL PRIMARY (6)	RESID SC1 GENERAL (7)	RESID SC3 T.O.U. (8)	RESID SC5 W/ SP HTG (9)	C&I SC2 SEC NON DEM (10)
	NET PLANT						
1	HIGH TENSION ≥ 69 KV - DEMAND	D	822,960	5,245,173	1,453	70,317	15,164
2	HIGH TENSION ≥ 69 KV - ENERGY	E	982,305	3,225,362	1,236	67,715	23,100
3	HIGH TENSION < 69 KV - DEMAND	D	6,002,347	45,728,200	12,664	613,033	132,200
4	HIGH TENSION < 69 KV - ENERGY	E	6,890,944	28,536,878	10,936	599,122	204,384
5							
6	TRANSFORMERS - OH - DEMAND	D	0	6,289,739	1,742	84,320	30,061
7	TRANSFORMERS - OH - ENERGY	E	0	4,191,684	1,606	88,003	18,160
8	TRANSFORMERS - UG - DEMAND	D	0	3,716,139	1,029	49,819	17,761
9	TRANSFORMERS - UG - ENERGY	E	0	2,476,554	949	51,994	10,729
10							
11	OH LINES DEMAND	D	0	12,211,867	3,382	163,712	58,365
12	OH LINES ENERGY	E	0	8,138,381	3,119	170,862	35,258
13	UG LINES DEMAND	D	0	546,839	151	7,331	2,614
14	UG LINES ENERGY	E	0	364,431	140	7,651	1,579
15							
16	SERVICES - OH - DEMAND	C	159,774	1,217,218	337	16,318	3,519
17	SERVICES - OH - ENERGY	C	183,705	760,761	292	15,972	5,449
18	SERVICES - UG - DEMAND	C	396,440	3,020,237	836	40,489	8,731
19	SERVICES - UG - ENERGY	C	455,820	1,887,647	723	39,630	13,520
20							
21	METER & METER INSTALLATIONS	C	68,977	5,171,731	8,326	182,539	78,724
22	INSTALL. ON CUSTR PREMISES	C	395,653	0	0	0	0
23	STREET LIGHTING	C	0	0	0	0	0
24	CUSTOMER ACCOUNTING	C	602	868,340	243	23,853	18,829
25	UNCOLLECTIBLES	R	0	0	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	42,569	139,772	54	2,934	1,001
27	REVENUES	R	0	0	0	0	0
28			-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D	6,825,307	73,737,957	20,420	988,532	256,164
30	TOTAL ENERGY	E	7,915,818	47,073,063	18,040	988,283	294,211
31	TOTAL CUSTOMER	C	1,660,970	12,925,933	10,758	318,801	128,771
32	TOTAL REVENUE	R	0	0	0	0	0
33			-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL		16,402,094	133,736,953	49,218	2,295,616	679,147
			===========	===========	===========	===========	===========

			C&I SC2 SEC GEN SERV (11)	C&I SC2 SEC SPACE HTG (12)	C&I SC2 PRIMARY GEN (13)	SC4 MUNI STR LTG (14)	SC6 DUSK TO DAWN (15)	SC6 ENERGY LTG (16)
	NET PLANT							
1	HIGH TENSION ≥ 69 KV - DEMAND	D	2,653,772	130,818	365,339	37,084	19,918	11,664
2	HIGH TENSION ≥ 69 KV - ENERGY	E	2,222,931	120,612	375,402	28,312	14,974	9,409
3	HIGH TENSION < 69 KV - DEMAND	D	23,135,983	1,140,490	3,185,083	323,305	173,645	101,692
4	HIGH TENSION < 69 KV - ENERGY	E	19,667,718	1,067,136	3,321,422	250,491	132,488	83,246
5								
6	TRANSFORMERS - OH - DEMAND	D	3,182,266	156,870	0	44,469	23,884	13,987
7	TRANSFORMERS - OH - ENERGY	E	2,888,924	156,748	0	36,794	19,461	12,228
8	TRANSFORMERS - UG - DEMAND	D	1,880,164	92,683	0	26,274	14,111	8,264
9	TRANSFORMERS - UG - ENERGY	E	1,706,850	92,611	0	21,739	11,498	7,224
10								
11	OH LINES DEMAND	D	6,178,541	304,572	0	86,340	46,372	27,157
12	OH LINES ENERGY	E	5,609,001	304,334	0	71,437	37,784	23,741
13	UG LINES DEMAND	D	276,671	13,639	0	3,866	2,077	1,216
14	UG LINES ENERGY	E	251,167	13,628	0	3,199	1,692	1,063
15								
16	SERVICES - OH - DEMAND	C	615,846	30,358	84,782	0	0	2,707
17	SERVICES - OH - ENERGY	C	524,319	28,449	88,545	0	0	0
18	SERVICES - UG - DEMAND	C	1,528,076	75,327	210,367	0	0	6,717
19	SERVICES - UG - ENERGY	C	1,300,973	70,588	219,704	0	0	0
20								
21	METER & METER INSTALLATIONS	C	2,533,106	48,441	68,811	0	0	18,392
22	INSTALL. ON CUSTR PREMISES	C	0	0	0	0	0	0
23	STREET LIGHTING	C	0	0	0	1,854,605	996,522	0
24	CUSTOMER ACCOUNTING	C	100,764	2,289	1,072	292	7,607	1,420
25	UNCOLLECTIBLES	R	0	0	0	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	96,331	5,227	16,268	1,227	649	408
27	REVENUES	R	0	0	0	0	0	0
28			-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D	37,307,398	1,839,071	3,550,422	521,338	280,007	163,982
30	TOTAL ENERGY	E	32,442,922	1,760,296	3,713,091	413,198	218,546	137,318
31	TOTAL CUSTOMER	C	6,603,083	255,453	673,281	1,854,896	1,004,128	29,235
32	TOTAL REVENUE	R	0	0	0	0	0	0
33			-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL		76,353,404	3,854,819	7,936,795	2,789,433	1,502,681	330,535
			===========	===========	===========	===========	===========	===========

			SC7 PRIMARY T.O.U. (17)	SC7 SEP MET SP HTG (18)	SC7 HV TOD (19)
	NET PLANT				
1	HIGH TENSION ≥ 69 KV - DEMAND	D	642,205	46,284	134,471
2	HIGH TENSION ≥ 69 KV - ENERGY	E	754,474	24,371	203,460
3	HIGH TENSION < 69 KV - DEMAND	D	5,598,839	403,508	0
4	HIGH TENSION < 69 KV - ENERGY	E	6,675,320	215,624	0
5					
6	TRANSFORMERS - OH - DEMAND	D	0	0	0
7	TRANSFORMERS - OH - ENERGY	E	0	0	0
8	TRANSFORMERS - UG - DEMAND	D	0	0	0
9	TRANSFORMERS - UG - ENERGY	E	0	0	0
10					
11	OH LINES DEMAND	D	0	0	0
12	OH LINES ENERGY	E	0	0	0
13	UG LINES DEMAND	D	0	0	0
14	UG LINES ENERGY	E	0	0	0
15					
16	SERVICES - OH - DEMAND	C	149,033	10,741	0
17	SERVICES - OH - ENERGY	C	177,956	5,748	0
18	SERVICES - UG - DEMAND	C	369,790	26,651	0
19	SERVICES - UG - ENERGY	C	441,557	14,263	0
20					
21	METER & METER INSTALLATIONS	C	38,588	18,233	12,156
22	INSTALL. ON CUSTR PREMISES	C	299,816	95,837	0
23	STREET LIGHTING	C	0	0	0
24	CUSTOMER ACCOUNTING	C	542	42	17
25	UNCOLLECTIBLES	R	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	32,695	1,056	8,817
27	REVENUES	R	0	0	0
28			-------------------	-------------------	-------------------
29	TOTAL DEMAND	D	6,241,044	449,791	134,471
30	TOTAL ENERGY	E	7,462,490	241,051	212,277
31	TOTAL CUSTOMER	C	1,477,282	171,516	12,173
32	TOTAL REVENUE	R	0	0	0
33			-------------------	-------------------	-------------------
34	TOTAL		15,180,815	862,358	358,921
			===========	===========	===========

				TOTAL COMPANY (1)	TOTAL RESIDENTIAL (2)	TOTAL C&I (3)	MUNICIPAL LIGHTING (4)	PRIVATE LIGHTING (5)
	RATE BASE ADJUSTMENTS							
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	(2,245,386)	(1,273,631)	(758,173)	(8,883)	(7,565)
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	(1,693,888)	(789,127)	(656,835)	(6,782)	(5,841)
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	(18,411,907)	(10,595,630)	(6,307,415)	(73,901)	(62,937)
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	(13,889,684)	(6,662,442)	(5,545,531)	(57,258)	(49,313)
5								
6	TRANSFORMERS - OH - DEMAND	D	AP2D	(2,390,941)	(1,551,200)	(819,708)	(10,819)	(9,214)
7	TRANSFORMERS - OH - ENERGY	E	AP2E	(1,803,693)	(1,041,617)	(745,414)	(8,952)	(7,710)
8	TRANSFORMERS - UG - DEMAND	D	AP2D	(1,412,629)	(916,489)	(484,305)	(6,392)	(5,444)
9	TRANSFORMERS - UG - ENERGY	E	AP2E	(1,065,668)	(615,414)	(440,410)	(5,289)	(4,555)
10								
11	OH LINES DEMAND	D	AP2D	(1,434,234)	(930,505)	(491,712)	(6,490)	(5,527)
12	OH LINES ENERGY	E	AP2E	(1,081,966)	(624,826)	(447,146)	(5,370)	(4,625)
13	UG LINES DEMAND	D	AP2D	(57,915)	(37,574)	(19,856)	(262)	(223)
14	UG LINES ENERGY	E	AP2E	(43,691)	(25,231)	(18,056)	(217)	(187)
15								
16	SERVICES - OH - DEMAND	C	C02	(189,770)	(109,886)	(65,414)	0	(241)
17	SERVICES - OH - ENERGY	C	E02	(143,160)	(69,200)	(57,599)	0	0
18	SERVICES - UG - DEMAND	C	C02	(447,462)	(259,103)	(154,240)	0	(568)
19	SERVICES - UG - ENERGY	C	E02	(337,559)	(163,168)	(135,814)	0	0
20								
21	METER & METER INSTALLATIONS	C	S01	(1,677,859)	(1,100,089)	(559,847)	0	(3,773)
22	INSTALL. ON CUSTR PREMISES	C	C03	(103,986)	0	0	0	0
23	STREET LIGHTING	C	C04	(883,109)	0	0	(574,446)	(308,663)
24	CUSTOMER ACCOUNTING	C	S02	(220,062)	(191,543)	(26,389)	(63)	(1,937)
25	UNCOLLECTIBLES	R	S03	0	0	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	E01	(65,771)	(30,641)	(25,504)	(263)	(227)
27	REVENUES	R	R99	0	0	0	0	0
28				-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		(25,953,013)	(15,305,030)	(8,881,168)	(106,748)	(90,910)
30	TOTAL ENERGY	E		(19,644,360)	(9,789,297)	(7,878,896)	(84,130)	(72,456)
31	TOTAL CUSTOMER	C		(4,002,968)	(1,892,990)	(999,304)	(574,509)	(315,183)
32	TOTAL REVENUE	R		0	0	0	0	0
33				-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL			(49,600,341)	(26,987,317)	(17,759,368)	(765,387)	(478,549)
				===========	===========	===========	===========	===========

				TOTAL PRIMARY (6)	RESID SC1 GENERAL (7)	RESID SC3 T.O.U. (8)	RESID SC5 W/ SP HTG (9)	C&I SC2 SEC NON DEM (10)
	RATE BASE ADJUSTMENTS							
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	(197,134)	(1,256,439)	(348)	(16,844)	(3,632)
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	(235,303)	(772,610)	(296)	(16,221)	(5,534)
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	(1,372,024)	(10,452,608)	(2,895)	(140,128)	(30,218)
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	(1,575,140)	(6,522,995)	(2,500)	(136,948)	(46,718)
5								
6	TRANSFORMERS - OH - DEMAND	D	AP2D	0	(1,530,261)	(424)	(20,515)	(7,314)
7	TRANSFORMERS - OH - ENERGY	E	AP2E	0	(1,019,815)	(391)	(21,411)	(4,418)
8	TRANSFORMERS - UG - DEMAND	D	AP2D	0	(904,118)	(250)	(12,121)	(4,321)
9	TRANSFORMERS - UG - ENERGY	E	AP2E	0	(602,533)	(231)	(12,650)	(2,610)
10								
11	OH LINES DEMAND	D	AP2D	0	(917,945)	(254)	(12,306)	(4,387)
12	OH LINES ENERGY	E	AP2E	0	(611,748)	(234)	(12,843)	(2,650)
13	UG LINES DEMAND	D	AP2D	0	(37,067)	(10)	(497)	(177)
14	UG LINES ENERGY	E	AP2E	0	(24,703)	(9)	(519)	(107)
15								
16	SERVICES - OH - DEMAND	C	C02	(14,229)	(108,403)	(30)	(1,453)	(313)
17	SERVICES - OH - ENERGY	C	E02	(16,360)	(67,752)	(26)	(1,422)	(485)
18	SERVICES - UG - DEMAND	C	C02	(33,551)	(255,605)	(71)	(3,427)	(739)
19	SERVICES - UG - ENERGY	C	E02	(38,576)	(159,753)	(61)	(3,354)	(1,144)
20								
21	METER & METER INSTALLATIONS	C	S01	(14,150)	(1,060,935)	(1,708)	(37,446)	(16,150)
22	INSTALL. ON CUSTR PREMISES	C	C03	(103,986)	0	0	0	0
23	STREET LIGHTING	C	C04	0	0	0	0	0
24	CUSTOMER ACCOUNTING	C	S02	(129)	(186,371)	(52)	(5,119)	(4,041)
25	UNCOLLECTIBLES	R	S03	0	0	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	E01	(9,136)	(29,999)	(11)	(630)	(215)
27	REVENUES	R	R99	0	0	0	0	0
28				-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		(1,569,157)	(15,098,439)	(4,181)	(202,410)	(50,050)
30	TOTAL ENERGY	E		(1,819,580)	(9,584,403)	(3,673)	(201,221)	(62,253)
31	TOTAL CUSTOMER	C		(220,983)	(1,838,820)	(1,948)	(52,222)	(22,872)
32	TOTAL REVENUE	R		0	0	0	0	0
33				-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL			(3,609,720)	(26,521,661)	(9,802)	(455,853)	(135,175)
				===========	===========	===========	===========	===========

				C&I SC2 SEC GEN SERV (11)	C&I SC2 SEC SPACE HTG (12)	C&I SC2 PRIMARY GEN (13)	SC4 MUNI STR LTG (14)	SC6 DUSK TO DAWN (15)	SC6 ENERGY LTG (16)
	RATE BASE ADJUSTMENTS								
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	(635,690)	(31,336)	(87,514)	(8,883)	(4,771)	(2,794)
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	(532,485)	(28,892)	(89,924)	(6,782)	(3,587)	(2,254)
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	(5,288,451)	(260,695)	(728,050)	(73,901)	(39,692)	(23,245)
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	(4,495,671)	(243,927)	(759,215)	(57,258)	(30,284)	(19,028)
5									
6	TRANSFORMERS - OH - DEMAND	D	AP2D	(774,229)	(38,166)	0	(10,819)	(5,811)	(3,403)
7	TRANSFORMERS - OH - ENERGY	E	AP2E	(702,860)	(38,136)	0	(8,952)	(4,735)	(2,975)
8	TRANSFORMERS - UG - DEMAND	D	AP2D	(457,434)	(22,549)	0	(6,392)	(3,433)	(2,011)
9	TRANSFORMERS - UG - ENERGY	E	AP2E	(415,268)	(22,532)	0	(5,289)	(2,797)	(1,758)
10									
11	OH LINES DEMAND	D	AP2D	(464,430)	(22,894)	0	(6,490)	(3,486)	(2,041)
12	OH LINES ENERGY	E	AP2E	(421,619)	(22,876)	0	(5,370)	(2,840)	(1,785)
13	UG LINES DEMAND	D	AP2D	(18,754)	(924)	0	(262)	(141)	(82)
14	UG LINES ENERGY	E	AP2E	(17,025)	(924)	0	(217)	(115)	(72)
15									
16	SERVICES - OH - DEMAND	C	C02	(54,846)	(2,704)	(7,551)	0	0	(241)
17	SERVICES - OH - ENERGY	C	E02	(46,695)	(2,534)	(7,886)	0	0	0
18	SERVICES - UG - DEMAND	C	C02	(129,322)	(6,375)	(17,804)	0	0	(568)
19	SERVICES - UG - ENERGY	C	E02	(110,102)	(5,974)	(18,594)	0	0	0
20									
21	METER & METER INSTALLATIONS	C	S01	(519,644)	(9,937)	(14,116)	0	0	(3,773)
22	INSTALL. ON CUSTR PREMISES	C	C03	0	0	0	0	0	0
23	STREET LIGHTING	C	C04	0	0	0	(574,446)	(308,663)	0
24	CUSTOMER ACCOUNTING	C	S02	(21,627)	(491)	(230)	(63)	(1,633)	(305)
25	UNCOLLECTIBLES	R	S03	0	0	0	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	E01	(20,676)	(1,122)	(3,492)	(263)	(139)	(88)
27	REVENUES	R	R99	0	0	0	0	0	0
28				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		(7,638,989)	(376,565)	(815,564)	(106,748)	(57,334)	(33,577)
30	TOTAL ENERGY	E		(6,605,605)	(358,408)	(852,631)	(84,130)	(44,498)	(27,959)
31	TOTAL CUSTOMER	C		(882,237)	(28,015)	(66,179)	(574,509)	(310,296)	(4,887)
32	TOTAL REVENUE	R		0	0	0	0	0	0
33				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL			(15,126,831)	(762,988)	(1,734,374)	(765,387)	(412,127)	(66,423)
				===========	===========	===========	===========	===========	===========

				SC7 PRIMARY T.O.U. (17)	SC7 SEP MET SP HTG (18)	SC7 HV TOD (19)
	RATE BASE ADJUSTMENTS					
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	(153,835)	(11,087)	(32,212)
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	(180,728)	(5,838)	(48,737)
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	(1,279,789)	(92,234)	0
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	(1,525,853)	(49,288)	0
5						
6	TRANSFORMERS - OH - DEMAND	D	AP2D	0	0	0
7	TRANSFORMERS - OH - ENERGY	E	AP2E	0	0	0
8	TRANSFORMERS - UG - DEMAND	D	AP2D	0	0	0
9	TRANSFORMERS - UG - ENERGY	E	AP2E	0	0	0
10						
11	OH LINES DEMAND	D	AP2D	0	0	0
12	OH LINES ENERGY	E	AP2E	0	0	0
13	UG LINES DEMAND	D	AP2D	0	0	0
14	UG LINES ENERGY	E	AP2E	0	0	0
15						
16	SERVICES - OH - DEMAND	C	C02	(13,273)	(957)	0
17	SERVICES - OH - ENERGY	C	E02	(15,848)	(512)	0
18	SERVICES - UG - DEMAND	C	C02	(31,296)	(2,255)	0
19	SERVICES - UG - ENERGY	C	E02	(37,369)	(1,207)	0
20						
21	METER & METER INSTALLATIONS	C	S01	(7,916)	(3,740)	(2,494)
22	INSTALL. ON CUSTR PREMISES	C	C03	(78,798)	(25,188)	0
23	STREET LIGHTING	C	C04	0	0	0
24	CUSTOMER ACCOUNTING	C	S02	(116)	(9)	(4)
25	UNCOLLECTIBLES	R	S03	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	E01	(7,017)	(227)	(1,892)
27	REVENUES	R	R99	0	0	0
28				-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		(1,433,625)	(103,321)	(32,212)
30	TOTAL ENERGY	E		(1,713,599)	(55,352)	(50,630)
31	TOTAL CUSTOMER	C		(184,617)	(33,869)	(2,497)
32	TOTAL REVENUE	R		0	0	0
33				-------------------	-------------------	-------------------
34	TOTAL			(3,331,840)	(192,542)	(85,339)
				===========	===========	===========

				TOTAL COMPANY (1)	TOTAL RESIDENTIAL (2)	TOTAL C&I (3)	MUNICIPAL LIGHTING (4)	PRIVATE LIGHTING (5)
	WORKING CAPITAL							
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	246,303	139,708	83,166	974	830
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	185,807	86,561	72,050	744	641
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	2,097,957	1,207,326	718,702	8,421	7,171
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	1,582,669	759,156	631,889	6,524	5,619
5								
6	TRANSFORMERS - OH - DEMAND	D	AP2D	205,737	133,479	70,535	931	793
7	TRANSFORMERS - OH - ENERGY	E	AP2E	155,205	89,630	64,142	770	663
8	TRANSFORMERS - UG - DEMAND	D	AP2D	121,555	78,863	41,674	550	468
9	TRANSFORMERS - UG - ENERGY	E	AP2E	91,699	52,955	37,897	455	392
10								
11	OH LINES DEMAND	D	AP2D	691,366	448,546	237,027	3,128	2,664
12	OH LINES ENERGY	E	AP2E	521,557	301,195	215,545	2,588	2,229
13	UG LINES DEMAND	D	AP2D	18,640	12,093	6,391	84	72
14	UG LINES ENERGY	E	AP2E	14,062	8,121	5,811	70	60
15								
16	SERVICES - OH - DEMAND	C	C02	93,213	53,975	32,130	0	118
17	SERVICES - OH - ENERGY	C	E02	70,319	33,990	28,292	0	0
18	SERVICES - UG - DEMAND	C	C02	131,636	76,224	45,375	0	167
19	SERVICES - UG - ENERGY	C	E02	99,305	48,002	39,954	0	0
20								
21	METER & METER INSTALLATIONS	C	S01	178,590	117,092	59,590	0	402
22	INSTALL. ON CUSTR PREMISES	C	C03	8,965	0	0	0	0
23	STREET LIGHTING	C	C04	103,404	0	0	67,262	36,142
24	CUSTOMER ACCOUNTING	C	S02	533,778	464,604	64,010	152	4,699
25	UNCOLLECTIBLES	R	S03	41,318	22,913	15,063	556	302
26	CUSTOMER SERVICE AND 901 & 905	E	E01	133,768	62,318	51,871	536	461
27	REVENUES	R	R99	0	0	0	0	0
28				-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		3,381,557	2,020,015	1,157,495	14,089	11,999
30	TOTAL ENERGY	E		2,684,768	1,359,936	1,079,205	11,687	10,066
31	TOTAL CUSTOMER	C		1,219,210	793,888	269,351	67,414	41,528
32	TOTAL REVENUE	R		41,318	22,913	15,063	556	302
33				-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL			7,326,853	4,196,751	2,521,114	93,747	63,894
				===========	===========	===========	===========	===========

				TOTAL PRIMARY (6)	RESID SC1 GENERAL (7)	RESID SC3 T.O.U. (8)	RESID SC5 W/ SP HTG (9)	C&I SC2 SEC NON DEM (10)
	WORKING CAPITAL							
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	21,624	137,822	38	1,848	398
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	25,811	84,750	32	1,779	607
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	156,336	1,191,029	330	15,967	3,443
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	179,480	743,267	285	15,605	5,323
5								
6	TRANSFORMERS - OH - DEMAND	D	AP2D	0	131,677	36	1,765	629
7	TRANSFORMERS - OH - ENERGY	E	AP2E	0	87,754	34	1,842	380
8	TRANSFORMERS - UG - DEMAND	D	AP2D	0	77,798	22	1,043	372
9	TRANSFORMERS - UG - ENERGY	E	AP2E	0	51,847	20	1,089	225
10								
11	OH LINES DEMAND	D	AP2D	0	442,491	123	5,932	2,115
12	OH LINES ENERGY	E	AP2E	0	294,890	113	6,191	1,278
13	UG LINES DEMAND	D	AP2D	0	11,930	3	160	57
14	UG LINES ENERGY	E	AP2E	0	7,951	3	167	34
15								
16	SERVICES - OH - DEMAND	C	C02	6,989	53,246	15	714	154
17	SERVICES - OH - ENERGY	C	E02	8,036	33,279	13	699	238
18	SERVICES - UG - DEMAND	C	C02	9,870	75,195	21	1,008	217
19	SERVICES - UG - ENERGY	C	E02	11,349	46,997	18	987	337
20								
21	METER & METER INSTALLATIONS	C	S01	1,506	112,925	182	3,986	1,719
22	INSTALL. ON CUSTR PREMISES	C	C03	8,965	0	0	0	0
23	STREET LIGHTING	C	C04	0	0	0	0	0
24	CUSTOMER ACCOUNTING	C	S02	313	452,060	127	12,418	9,802
25	UNCOLLECTIBLES	R	S03	2,485	22,432	6	474	227
26	CUSTOMER SERVICE AND 901 & 905	E	E01	18,582	61,014	23	1,281	437
27	REVENUES	R	R99	0	0	0	0	0
28				-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		177,960	1,992,748	552	26,715	7,015
30	TOTAL ENERGY	E		223,874	1,331,472	510	27,954	8,284
31	TOTAL CUSTOMER	C		47,028	773,702	375	19,811	12,467
32	TOTAL REVENUE	R		2,485	22,432	6	474	227
33				-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL			451,347	4,120,355	1,443	74,953	27,993
				===========	===========	===========	===========	===========

				C&I SC2 SEC GEN SERV (11)	C&I SC2 SEC SPACE HTG (12)	C&I SC2 PRIMARY GEN (13)	SC4 MUNI STR LTG (14)	SC6 DUSK TO DAWN (15)	SC6 ENERGY LTG (16)
	WORKING CAPITAL								
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	69,731	3,437	9,600	974	523	306
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	58,410	3,169	9,864	744	393	247
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	602,596	29,705	82,958	8,421	4,523	2,649
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	512,262	27,794	86,509	6,524	3,451	2,168
5									
6	TRANSFORMERS - OH - DEMAND	D	AP2D	66,621	3,284	0	931	500	293
7	TRANSFORMERS - OH - ENERGY	E	AP2E	60,480	3,282	0	770	407	256
8	TRANSFORMERS - UG - DEMAND	D	AP2D	39,362	1,940	0	550	295	173
9	TRANSFORMERS - UG - ENERGY	E	AP2E	35,733	1,939	0	455	241	151
10									
11	OH LINES DEMAND	D	AP2D	223,877	11,036	0	3,128	1,680	984
12	OH LINES ENERGY	E	AP2E	203,240	11,027	0	2,588	1,369	860
13	UG LINES DEMAND	D	AP2D	6,036	298	0	84	45	27
14	UG LINES ENERGY	E	AP2E	5,480	297	0	70	37	23
15									
16	SERVICES - OH - DEMAND	C	C02	26,940	1,328	3,709	0	0	118
17	SERVICES - OH - ENERGY	C	E02	22,936	1,244	3,873	0	0	0
18	SERVICES - UG - DEMAND	C	C02	38,045	1,875	5,238	0	0	167
19	SERVICES - UG - ENERGY	C	E02	32,390	1,757	5,470	0	0	0
20									
21	METER & METER INSTALLATIONS	C	S01	55,310	1,058	1,502	0	0	402
22	INSTALL. ON CUSTR PREMISES	C	C03	0	0	0	0	0	0
23	STREET LIGHTING	C	C04	0	0	0	67,262	36,142	0
24	CUSTOMER ACCOUNTING	C	S02	52,458	1,192	558	152	3,960	739
25	UNCOLLECTIBLES	R	S03	12,697	529	1,610	556	238	63
26	CUSTOMER SERVICE AND 901 & 905	E	E01	42,051	2,282	7,101	536	283	178
27	REVENUES	R	R99	0	0	0	0	0	0
28				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		1,008,222	49,700	92,558	14,089	7,567	4,432
30	TOTAL ENERGY	E		917,655	49,790	103,475	11,687	6,182	3,884
31	TOTAL CUSTOMER	C		228,079	8,455	20,350	67,414	40,102	1,426
32	TOTAL REVENUE	R		12,697	529	1,610	556	238	63
33				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL			2,166,654	108,475	217,992	93,747	54,088	9,805
				===========	===========	===========	===========	===========	===========

				SC7 PRIMARY T.O.U. (17)	SC7 SEP MET SP HTG (18)	SC7 HV TOD (19)
	WORKING CAPITAL					
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	16,875	1,216	3,533
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	19,825	640	5,346
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	145,826	10,510	0
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	173,864	5,616	0
5						
6	TRANSFORMERS - OH - DEMAND	D	AP2D	0	0	0
7	TRANSFORMERS - OH - ENERGY	E	AP2E	0	0	0
8	TRANSFORMERS - UG - DEMAND	D	AP2D	0	0	0
9	TRANSFORMERS - UG - ENERGY	E	AP2E	0	0	0
10						
11	OH LINES DEMAND	D	AP2D	0	0	0
12	OH LINES ENERGY	E	AP2E	0	0	0
13	UG LINES DEMAND	D	AP2D	0	0	0
14	UG LINES ENERGY	E	AP2E	0	0	0
15						
16	SERVICES - OH - DEMAND	C	C02	6,519	470	0
17	SERVICES - OH - ENERGY	C	E02	7,785	251	0
18	SERVICES - UG - DEMAND	C	C02	9,207	664	0
19	SERVICES - UG - ENERGY	C	E02	10,993	355	0
20						
21	METER & METER INSTALLATIONS	C	S01	843	398	265
22	INSTALL. ON CUSTR PREMISES	C	C03	6,793	2,172	0
23	STREET LIGHTING	C	C04	0	0	0
24	CUSTOMER ACCOUNTING	C	S02	282	22	9
25	UNCOLLECTIBLES	R	S03	2,256	121	108
26	CUSTOMER SERVICE AND 901 & 905	E	E01	14,272	461	3,849
27	REVENUES	R	R99	0	0	0
28				-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		162,701	11,726	3,533
30	TOTAL ENERGY	E		207,961	6,717	9,195
31	TOTAL CUSTOMER	C		42,422	4,332	274
32	TOTAL REVENUE	R		2,256	121	108
33				-------------------	-------------------	-------------------
34	TOTAL			415,341	22,896	13,111
				===========	===========	===========

			TOTAL COMPANY (1)	TOTAL RESIDENTIAL (2)	TOTAL C&I (3)	MUNICIPAL LIGHTING (4)	PRIVATE LIGHTING (5)
	TOTAL RATE BASE						
1	HIGH TENSION ≥ 69 KV - DEMAND	D	7,374,578	4,183,019	2,490,086	29,175	24,847
2	HIGH TENSION ≥ 69 KV - ENERGY	E	5,563,278	2,591,748	2,157,260	22,274	19,183
3	HIGH TENSION < 69 KV - DEMAND	D	64,234,692	36,965,592	22,005,045	257,824	219,572
4	HIGH TENSION < 69 KV - ENERGY	E	48,457,750	23,243,650	19,347,017	199,758	172,040
5							
6	TRANSFORMERS - OH - DEMAND	D	7,642,135	4,958,080	2,620,024	34,581	29,450
7	TRANSFORMERS - OH - ENERGY	E	5,765,120	3,329,306	2,382,559	28,612	24,642
8	TRANSFORMERS - UG - DEMAND	D	4,515,169	2,929,361	1,547,977	20,431	17,400
9	TRANSFORMERS - UG - ENERGY	E	3,406,180	1,967,040	1,407,677	16,905	14,559
10							
11	OH LINES DEMAND	D	18,337,441	11,897,002	6,286,793	82,978	70,667
12	OH LINES ENERGY	E	13,833,508	7,988,730	5,716,992	68,656	59,129
13	UG LINES DEMAND	D	815,127	528,840	279,458	3,689	3,141
14	UG LINES ENERGY	E	614,921	355,111	254,129	3,052	2,628
15							
16	SERVICES - OH - DEMAND	C	2,034,303	1,177,962	701,223	0	2,584
17	SERVICES - OH - ENERGY	C	1,534,650	741,815	617,455	0	0
18	SERVICES - UG - DEMAND	C	4,971,395	2,878,684	1,713,636	0	6,315
19	SERVICES - UG - ENERGY	C	3,750,350	1,812,834	1,508,925	0	0
20							
21	METER & METER INSTALLATIONS	C	6,679,778	4,379,599	2,228,825	0	15,020
22	INSTALL. ON CUSTR PREMISES	C	300,631	0	0	0	0
23	STREET LIGHTING	C	2,071,421	0	0	1,347,421	724,000
24	CUSTOMER ACCOUNTING	C	1,339,025	1,165,497	160,574	381	11,788
25	UNCOLLECTIBLES	R	41,318	22,913	15,063	556	302
26	CUSTOMER SERVICE AND 901 & 905	E	374,437	174,438	145,195	1,499	1,291
27	REVENUES	R	0	0	0	0	0
28			-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D	102,919,142	61,461,894	35,229,382	428,679	365,077
30	TOTAL ENERGY	E	78,015,193	39,650,024	31,410,829	340,756	293,474
31	TOTAL CUSTOMER	C	22,681,552	12,156,390	6,930,637	1,347,802	759,708
32	TOTAL REVENUE	R	41,318	22,913	15,063	556	302
33			-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL		203,657,206	113,291,221	73,585,911	2,117,793	1,418,560
			===========	===========	===========	===========	===========

			TOTAL PRIMARY (6)	RESID SC1 GENERAL (7)	RESID SC3 T.O.U. (8)	RESID SC5 W/ SP HTG (9)	C&I SC2 SEC NON DEM (10)
	TOTAL RATE BASE						
1	HIGH TENSION ≥ 69 KV - DEMAND	D	647,451	4,126,556	1,143	55,321	11,930
2	HIGH TENSION ≥ 69 KV - ENERGY	E	772,813	2,537,502	972	53,274	18,174
3	HIGH TENSION < 69 KV - DEMAND	D	4,786,659	36,466,622	10,099	488,872	105,425
4	HIGH TENSION < 69 KV - ENERGY	E	5,495,284	22,757,150	8,721	477,779	162,989
5							
6	TRANSFORMERS - OH - DEMAND	D	0	4,891,155	1,355	65,571	23,377
7	TRANSFORMERS - OH - ENERGY	E	0	3,259,623	1,249	68,435	14,122
8	TRANSFORMERS - UG - DEMAND	D	0	2,889,820	800	38,741	13,812
9	TRANSFORMERS - UG - ENERGY	E	0	1,925,869	738	40,433	8,343
10							
11	OH LINES DEMAND	D	0	11,736,414	3,250	157,338	56,093
12	OH LINES ENERGY	E	0	7,821,523	2,997	164,210	33,885
13	UG LINES DEMAND	D	0	521,702	144	6,994	2,493
14	UG LINES ENERGY	E	0	347,679	133	7,299	1,506
15							
16	SERVICES - OH - DEMAND	C	152,534	1,162,062	322	15,579	3,360
17	SERVICES - OH - ENERGY	C	175,380	726,288	278	15,248	5,202
18	SERVICES - UG - DEMAND	C	372,760	2,839,827	786	38,071	8,210
19	SERVICES - UG - ENERGY	C	428,592	1,774,890	680	37,263	12,712
20							
21	METER & METER INSTALLATIONS	C	56,333	4,223,721	6,800	149,079	64,293
22	INSTALL. ON CUSTR PREMISES	C	300,631	0	0	0	0
23	STREET LIGHTING	C	0	0	0	0	0
24	CUSTOMER ACCOUNTING	C	786	1,134,028	317	31,151	24,590
25	UNCOLLECTIBLES	R	2,485	22,432	6	474	227
26	CUSTOMER SERVICE AND 901 & 905	E	52,014	170,787	65	3,586	1,223
27	REVENUES	R	0	0	0	0	0
28			-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D	5,434,110	60,632,267	16,791	812,837	213,129
30	TOTAL ENERGY	E	6,320,111	38,820,132	14,877	815,015	240,243
31	TOTAL CUSTOMER	C	1,487,016	11,860,816	9,184	286,390	118,366
32	TOTAL REVENUE	R	2,485	22,432	6	474	227
33			-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL		13,243,721	111,335,647	40,859	1,914,716	571,964
			===========	===========	===========	===========	===========

			C&I SC2 SEC GEN SERV (11)	C&I SC2 SEC SPACE HTG (12)	C&I SC2 PRIMARY GEN (13)	SC4 MUNI STR LTG (14)	SC6 DUSK TO DAWN (15)	SC6 ENERGY LTG (16)
	TOTAL RATE BASE							
1	HIGH TENSION ≥ 69 KV - DEMAND	D	2,087,813	102,919	287,425	29,175	15,670	9,177
2	HIGH TENSION ≥ 69 KV - ENERGY	E	1,748,855	94,890	295,341	22,274	11,781	7,402
3	HIGH TENSION < 69 KV - DEMAND	D	18,450,128	909,500	2,539,991	257,824	138,475	81,096
4	HIGH TENSION < 69 KV - ENERGY	E	15,684,309	851,003	2,648,716	199,758	105,655	66,386
5								
6	TRANSFORMERS - OH - DEMAND	D	2,474,658	121,988	0	34,581	18,573	10,877
7	TRANSFORMERS - OH - ENERGY	E	2,246,544	121,893	0	28,612	15,133	9,509
8	TRANSFORMERS - UG - DEMAND	D	1,462,092	72,074	0	20,431	10,974	6,427
9	TRANSFORMERS - UG - ENERGY	E	1,327,315	72,018	0	16,905	8,941	5,618
10								
11	OH LINES DEMAND	D	5,937,987	292,714	0	82,978	44,567	26,100
12	OH LINES ENERGY	E	5,390,621	292,486	0	68,656	36,313	22,816
13	UG LINES DEMAND	D	263,953	13,012	0	3,689	1,981	1,160
14	UG LINES ENERGY	E	239,621	13,001	0	3,052	1,614	1,014
15								
16	SERVICES - OH - DEMAND	C	587,940	28,983	80,940	0	0	2,584
17	SERVICES - OH - ENERGY	C	500,560	27,160	84,533	0	0	0
18	SERVICES - UG - DEMAND	C	1,436,798	70,827	197,801	0	0	6,315
19	SERVICES - UG - ENERGY	C	1,223,261	66,372	206,580	0	0	0
20								
21	METER & METER INSTALLATIONS	C	2,068,772	39,562	56,197	0	0	15,020
22	INSTALL. ON CUSTR PREMISES	C	0	0	0	0	0	0
23	STREET LIGHTING	C	0	0	0	1,347,421	724,000	0
24	CUSTOMER ACCOUNTING	C	131,595	2,990	1,400	381	9,934	1,854
25	UNCOLLECTIBLES	R	12,697	529	1,610	556	238	63
26	CUSTOMER SERVICE AND 901 & 905	E	117,707	6,387	19,878	1,499	793	498
27	REVENUES	R	0	0	0	0	0	0
28			-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D	30,676,631	1,512,207	2,827,416	428,679	230,240	134,837
30	TOTAL ENERGY	E	26,754,973	1,451,678	2,963,935	340,756	180,230	113,243
31	TOTAL CUSTOMER	C	5,948,926	235,893	627,452	1,347,802	733,934	25,774
32	TOTAL REVENUE	R	12,697	529	1,610	556	238	63
33			-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL		63,393,227	3,200,306	6,420,413	2,117,793	1,144,643	273,917
			===========	===========	===========	===========	===========	===========

			SC7 PRIMARY T.O.U. (17)	SC7 SEP MET SP HTG (18)	SC7 HV TOD (19)
	TOTAL RATE BASE				
1	HIGH TENSION ≥ 69 KV - DEMAND	D	505,244	36,413	105,793
2	HIGH TENSION ≥ 69 KV - ENERGY	E	593,570	19,173	160,069
3	HIGH TENSION < 69 KV - DEMAND	D	4,464,876	321,783	0
4	HIGH TENSION < 69 KV - ENERGY	E	5,323,332	171,952	0
5					
6	TRANSFORMERS - OH - DEMAND	D	0	0	0
7	TRANSFORMERS - OH - ENERGY	E	0	0	0
8	TRANSFORMERS - UG - DEMAND	D	0	0	0
9	TRANSFORMERS - UG - ENERGY	E	0	0	0
10					
11	OH LINES DEMAND	D	0	0	0
12	OH LINES ENERGY	E	0	0	0
13	UG LINES DEMAND	D	0	0	0
14	UG LINES ENERGY	E	0	0	0
15					
16	SERVICES - OH - DEMAND	C	142,280	10,254	0
17	SERVICES - OH - ENERGY	C	169,893	5,488	0
18	SERVICES - UG - DEMAND	C	347,701	25,059	0
19	SERVICES - UG - ENERGY	C	415,181	13,411	0
20					
21	METER & METER INSTALLATIONS	C	31,514	14,891	9,927
22	INSTALL. ON CUSTR PREMISES	C	227,811	72,820	0
23	STREET LIGHTING	C	0	0	0
24	CUSTOMER ACCOUNTING	C	708	55	22
25	UNCOLLECTIBLES	R	2,256	121	108
26	CUSTOMER SERVICE AND 901 & 905	E	39,950	1,290	10,773
27	REVENUES	R	0	0	0
28			-------------------	-------------------	-------------------
29	TOTAL DEMAND	D	4,970,120	358,196	105,793
30	TOTAL ENERGY	E	5,956,852	192,416	170,843
31	TOTAL CUSTOMER	C	1,335,087	141,979	9,950
32	TOTAL REVENUE	R	2,256	121	108
33			-------------------	-------------------	-------------------
34	TOTAL		12,264,316	692,711	286,694
			===========	===========	===========

				TOTAL COMPANY (1)	TOTAL RESIDENTIAL (2)	TOTAL C&I (3)	MUNICIPAL LIGHTING (4)	PRIVATE LIGHTING (5)
	OPERATION & MAINTENANCE							
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	1,338,380	759,158	451,915	5,295	4,509
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	1,009,655	470,365	391,512	4,042	3,481
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	11,763,948	6,769,883	4,030,006	47,218	40,212
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	8,874,558	4,256,845	3,543,215	36,584	31,507
5								
6	TRANSFORMERS - OH - DEMAND	D	AP2D	631,151	409,479	216,383	2,856	2,432
7	TRANSFORMERS - OH - ENERGY	E	AP2E	476,131	274,962	196,771	2,363	2,035
8	TRANSFORMERS - UG - DEMAND	D	AP2D	372,900	241,931	127,845	1,687	1,437
9	TRANSFORMERS - UG - ENERGY	E	AP2E	281,310	162,454	116,258	1,396	1,202
10								
11	OH LINES DEMAND	D	AP2D	5,725,198	3,714,406	1,962,822	25,907	22,063
12	OH LINES ENERGY	E	AP2E	4,319,009	2,494,190	1,784,923	21,435	18,461
13	UG LINES DEMAND	D	AP2D	63,756	41,364	21,858	289	246
14	UG LINES ENERGY	E	AP2E	48,097	27,776	19,877	239	206
15								
16	SERVICES - OH - DEMAND	C	C02	785,344	454,753	270,707	0	998
17	SERVICES - OH - ENERGY	C	E02	592,452	286,378	238,369	0	0
18	SERVICES - UG - DEMAND	C	C02	435,012	251,894	149,948	0	553
19	SERVICES - UG - ENERGY	C	E02	328,167	158,629	132,036	0	0
20								
21	METER & METER INSTALLATIONS	C	S01	843,375	552,959	281,407	0	1,896
22	INSTALL. ON CUSTR PREMISES	C	C03	26,366	0	0	0	0
23	STREET LIGHTING	C	C04	701,417	0	0	456,258	245,158
24	CUSTOMER ACCOUNTING	C	S02	7,702,380	6,704,205	923,657	2,191	67,807
25	UNCOLLECTIBLES	R	S03	611,945	339,347	223,087	8,240	4,466
26	CUSTOMER SERVICE AND 901 & 905	E	E01	2,061,623	960,442	799,431	8,254	7,109
27	REVENUES	R	R99	0	0	0	0	0
28				-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		19,895,333	11,936,220	6,810,829	83,252	70,900
30	TOTAL ENERGY	E		17,070,383	8,647,034	6,851,986	74,313	64,002
31	TOTAL CUSTOMER	C		11,414,513	8,408,817	1,996,124	458,450	316,412
32	TOTAL REVENUE	R		611,945	339,347	223,087	8,240	4,466
33				-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL			48,992,174	29,331,418	15,882,026	624,255	455,779
				===========	===========	===========	===========	===========

				TOTAL PRIMARY (6)	RESID SC1 GENERAL (7)	RESID SC3 T.O.U. (8)	RESID SC5 W/ SP HTG (9)	C&I SC2 SEC NON DEM (10)
	OPERATION & MAINTENANCE							
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	117,503	748,910	207	10,040	2,165
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	140,254	460,520	176	9,668	3,298
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	876,629	6,678,501	1,849	89,532	19,308
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	1,006,407	4,167,747	1,597	87,500	29,850
5								
6	TRANSFORMERS - OH - DEMAND	D	AP2D	0	403,952	112	5,415	1,931
7	TRANSFORMERS - OH - ENERGY	E	AP2E	0	269,207	103	5,652	1,166
8	TRANSFORMERS - UG - DEMAND	D	AP2D	0	238,665	66	3,200	1,141
9	TRANSFORMERS - UG - ENERGY	E	AP2E	0	159,054	61	3,339	689
10								
11	OH LINES DEMAND	D	AP2D	0	3,664,268	1,015	49,123	17,513
12	OH LINES ENERGY	E	AP2E	0	2,441,986	936	51,269	10,579
13	UG LINES DEMAND	D	AP2D	0	40,806	11	547	195
14	UG LINES ENERGY	E	AP2E	0	27,194	10	571	118
15								
16	SERVICES - OH - DEMAND	C	C02	58,886	448,615	124	6,014	1,297
17	SERVICES - OH - ENERGY	C	E02	67,706	280,384	107	5,887	2,008
18	SERVICES - UG - DEMAND	C	C02	32,618	248,494	69	3,331	718
19	SERVICES - UG - ENERGY	C	E02	37,503	155,308	60	3,261	1,112
20								
21	METER & METER INSTALLATIONS	C	S01	7,113	533,278	859	18,822	8,118
22	INSTALL. ON CUSTR PREMISES	C	C03	26,366	0	0	0	0
23	STREET LIGHTING	C	C04	0	0	0	0	0
24	CUSTOMER ACCOUNTING	C	S02	4,520	6,523,192	1,826	179,187	141,445
25	UNCOLLECTIBLES	R	S03	36,805	332,233	96	7,018	3,355
26	CUSTOMER SERVICE AND 901 & 905	E	E01	286,387	940,340	360	19,742	6,735
27	REVENUES	R	R99	0	0	0	0	0
28				------------------	------------------	------------------	------------------	------------------
29	TOTAL DEMAND	D		994,132	11,775,102	3,261	157,857	42,252
30	TOTAL ENERGY	E		1,433,048	8,466,047	3,244	177,742	52,436
31	TOTAL CUSTOMER	C		234,711	8,189,271	3,045	216,502	154,698
32	TOTAL REVENUE	R		36,805	332,233	96	7,018	3,355
33				------------------	------------------	------------------	------------------	------------------
34	TOTAL			2,698,695	28,762,653	9,646	559,119	252,741
				===========	===========	===========	===========	===========

				C&I SC2 SEC GEN SERV (11)	C&I SC2 SEC SPACE HTG (12)	C&I SC2 PRIMARY GEN (13)	SC4 MUNI STR LTG (14)	SC6 DUSK TO DAWN (15)	SC6 ENERGY LTG (16)
	OPERATION & MAINTENANCE								
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	378,908	18,678	52,163	5,295	2,844	1,665
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	317,392	17,221	53,600	4,042	2,138	1,343
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	3,378,958	166,566	465,174	47,218	25,360	14,852
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	2,872,426	155,853	485,086	36,584	19,350	12,158
5									
6	TRANSFORMERS - OH - DEMAND	D	AP2D	204,378	10,075	0	2,856	1,534	898
7	TRANSFORMERS - OH - ENERGY	E	AP2E	185,538	10,067	0	2,363	1,250	785
8	TRANSFORMERS - UG - DEMAND	D	AP2D	120,752	5,952	0	1,687	906	531
9	TRANSFORMERS - UG - ENERGY	E	AP2E	109,621	5,948	0	1,396	738	464
10									
11	OH LINES DEMAND	D	AP2D	1,853,920	91,389	0	25,907	13,914	8,149
12	OH LINES ENERGY	E	AP2E	1,683,025	91,318	0	21,435	11,337	7,124
13	UG LINES DEMAND	D	AP2D	20,645	1,018	0	289	155	91
14	UG LINES ENERGY	E	AP2E	18,742	1,017	0	239	126	79
15									
16	SERVICES - OH - DEMAND	C	C02	226,975	11,189	31,247	0	0	998
17	SERVICES - OH - ENERGY	C	E02	193,242	10,485	32,634	0	0	0
18	SERVICES - UG - DEMAND	C	C02	125,724	6,198	17,308	0	0	553
19	SERVICES - UG - ENERGY	C	E02	107,039	5,808	18,076	0	0	0
20									
21	METER & METER INSTALLATIONS	C	S01	261,199	4,995	7,095	0	0	1,896
22	INSTALL. ON CUSTR PREMISES	C	C03	0	0	0	0	0	0
23	STREET LIGHTING	C	C04	0	0	0	456,258	245,158	0
24	CUSTOMER ACCOUNTING	C	S02	756,963	17,198	8,051	2,191	57,143	10,664
25	UNCOLLECTIBLES	R	S03	188,055	7,834	23,843	8,240	3,528	938
26	CUSTOMER SERVICE AND 901 & 905	E	E01	648,086	35,164	109,447	8,254	4,366	2,743
27	REVENUES	R	R99	0	0	0	0	0	0
28				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		5,957,561	293,678	517,338	83,252	44,714	26,186
30	TOTAL ENERGY	E		5,834,830	316,588	648,133	74,313	39,305	24,697
31	TOTAL CUSTOMER	C		1,671,142	55,872	114,412	458,450	302,301	14,111
32	TOTAL REVENUE	R		188,055	7,834	23,843	8,240	3,528	938
33				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL			13,651,588	673,972	1,303,726	624,255	389,848	65,932
				===========	===========	===========	===========	===========	===========

				SC7 PRIMARY T.O.U. (17)	SC7 SEP MET SP HTG (18)	SC7 HV TOD (19)
	OPERATION & MAINTENANCE					
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	91,695	6,608	19,200
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	107,724	3,480	29,050
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	817,698	58,931	0
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	974,916	31,491	0
5						
6	TRANSFORMERS - OH - DEMAND	D	AP2D	0	0	0
7	TRANSFORMERS - OH - ENERGY	E	AP2E	0	0	0
8	TRANSFORMERS - UG - DEMAND	D	AP2D	0	0	0
9	TRANSFORMERS - UG - ENERGY	E	AP2E	0	0	0
10						
11	OH LINES DEMAND	D	AP2D	0	0	0
12	OH LINES ENERGY	E	AP2E	0	0	0
13	UG LINES DEMAND	D	AP2D	0	0	0
14	UG LINES ENERGY	E	AP2E	0	0	0
15						
16	SERVICES - OH - DEMAND	C	C02	54,927	3,959	0
17	SERVICES - OH - ENERGY	C	E02	65,587	2,119	0
18	SERVICES - UG - DEMAND	C	C02	30,425	2,193	0
19	SERVICES - UG - ENERGY	C	E02	36,330	1,174	0
20						
21	METER & METER INSTALLATIONS	C	S01	3,979	1,880	1,253
22	INSTALL. ON CUSTR PREMISES	C	C03	19,979	6,386	0
23	STREET LIGHTING	C	C04	0	0	0
24	CUSTOMER ACCOUNTING	C	S02	4,074	318	128
25	UNCOLLECTIBLES	R	S03	33,415	1,786	1,604
26	CUSTOMER SERVICE AND 901 & 905	E	E01	219,963	7,105	59,318
27	REVENUES	R	R99	0	0	0
28				-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		909,392	65,540	19,200
30	TOTAL ENERGY	E		1,302,603	42,076	88,368
31	TOTAL CUSTOMER	C		215,301	18,028	1,381
32	TOTAL REVENUE	R		33,415	1,786	1,604
33				-------------------	-------------------	-------------------
34	TOTAL			2,460,712	127,431	110,553
				===========	===========	===========

				TOTAL COMPANY (1)	TOTAL RESIDENTIAL (2)	TOTAL C&I (3)	MUNICIPAL LIGHTING (4)	PRIVATE LIGHTING (5)
	DEPRECIATION & AMORTIZATION							
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	21,272	12,066	7,183	84	72
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	16,047	7,476	6,223	64	55
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	200,432	115,344	68,663	804	685
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	151,203	72,527	60,369	623	537
5								
6	TRANSFORMERS - OH - DEMAND	D	AP2D	30,878	20,033	10,586	140	119
7	TRANSFORMERS - OH - ENERGY	E	AP2E	23,294	13,452	9,627	116	100
8	TRANSFORMERS - UG - DEMAND	D	AP2D	18,243	11,836	6,255	83	70
9	TRANSFORMERS - UG - ENERGY	E	AP2E	13,762	7,948	5,688	68	59
10								
11	OH LINES DEMAND	D	AP2D	50,044	32,467	17,157	226	193
12	OH LINES ENERGY	E	AP2E	37,752	21,802	15,602	187	161
13	UG LINES DEMAND	D	AP2D	1,796	1,165	616	8	7
14	UG LINES ENERGY	E	AP2E	1,355	783	560	7	6
15								
16	SERVICES - OH - DEMAND	C	C02	6,436	3,726	2,218	0	8
17	SERVICES - OH - ENERGY	C	E02	4,855	2,347	1,953	0	0
18	SERVICES - UG - DEMAND	C	C02	14,485	8,388	4,993	0	18
19	SERVICES - UG - ENERGY	C	E02	10,927	5,282	4,397	0	0
20								
21	METER & METER INSTALLATIONS	C	S01	49,260	32,297	16,436	0	111
22	INSTALL. ON CUSTR PREMISES	C	C03	1,555	0	0	0	0
23	STREET LIGHTING	C	C04	13,063	0	0	8,497	4,566
24	CUSTOMER ACCOUNTING	C	S02	11,254	9,796	1,350	3	99
25	UNCOLLECTIBLES	R	S03	0	0	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	E01	3,364	1,567	1,304	13	12
27	REVENUES	R	R99	0	0	0	0	0
28				-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		322,665	192,912	110,459	1,346	1,146
30	TOTAL ENERGY	E		246,778	125,554	99,372	1,079	929
31	TOTAL CUSTOMER	C		111,835	61,836	31,347	8,500	4,802
32	TOTAL REVENUE	R		0	0	0	0	0
33				-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL			681,279	380,302	241,178	10,925	6,877
				===========	===========	===========	===========	===========

				TOTAL PRIMARY (6)	RESID SC1 GENERAL (7)	RESID SC3 T.O.U. (8)	RESID SC5 W/ SP HTG (9)	C&I SC2 SEC NON DEM (10)
	DEPRECIATION & AMORTIZATION							
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	1,868	11,903	3	160	34
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	2,229	7,319	3	154	52
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	14,936	113,787	32	1,525	329
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	17,147	71,009	27	1,491	509
5								
6	TRANSFORMERS - OH - DEMAND	D	AP2D	0	19,762	5	265	94
7	TRANSFORMERS - OH - ENERGY	E	AP2E	0	13,170	5	277	57
8	TRANSFORMERS - UG - DEMAND	D	AP2D	0	11,676	3	157	56
9	TRANSFORMERS - UG - ENERGY	E	AP2E	0	7,781	3	163	34
10								
11	OH LINES DEMAND	D	AP2D	0	32,029	9	429	153
12	OH LINES ENERGY	E	AP2E	0	21,345	8	448	92
13	UG LINES DEMAND	D	AP2D	0	1,150	0	15	5
14	UG LINES ENERGY	E	AP2E	0	766	0	16	3
15								
16	SERVICES - OH - DEMAND	C	C02	483	3,676	1	49	11
17	SERVICES - OH - ENERGY	C	E02	555	2,298	1	48	16
18	SERVICES - UG - DEMAND	C	C02	1,086	8,274	2	111	24
19	SERVICES - UG - ENERGY	C	E02	1,249	5,171	2	109	37
20								
21	METER & METER INSTALLATIONS	C	S01	415	31,148	50	1,099	474
22	INSTALL. ON CUSTR PREMISES	C	C03	1,555	0	0	0	0
23	STREET LIGHTING	C	C04	0	0	0	0	0
24	CUSTOMER ACCOUNTING	C	S02	7	9,531	3	262	207
25	UNCOLLECTIBLES	R	S03	0	0	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	E01	467	1,534	1	32	11
27	REVENUES	R	R99	0	0	0	0	0
28				-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		16,803	190,308	53	2,551	672
30	TOTAL ENERGY	E		19,843	122,926	47	2,581	759
31	TOTAL CUSTOMER	C		5,350	60,099	59	1,678	769
32	TOTAL REVENUE	R		0	0	0	0	0
33				-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL			41,997	373,333	159	6,810	2,200
				===========	===========	===========	===========	===========

				C&I SC2 SEC GEN SERV (11)	C&I SC2 SEC SPACE HTG (12)	C&I SC2 PRIMARY GEN (13)	SC4 MUNI STR LTG (14)	SC6 DUSK TO DAWN (15)	SC6 ENERGY LTG (16)
	DEPRECIATION & AMORTIZATION								
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	6,022	297	829	84	45	26
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	5,045	274	852	64	34	21
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	57,570	2,838	7,926	804	432	253
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	48,940	2,655	8,265	623	330	207
5									
6	TRANSFORMERS - OH - DEMAND	D	AP2D	9,999	493	0	140	75	44
7	TRANSFORMERS - OH - ENERGY	E	AP2E	9,077	493	0	116	61	38
8	TRANSFORMERS - UG - DEMAND	D	AP2D	5,908	291	0	83	44	26
9	TRANSFORMERS - UG - ENERGY	E	AP2E	5,363	291	0	68	36	23
10									
11	OH LINES DEMAND	D	AP2D	16,205	799	0	226	122	71
12	OH LINES ENERGY	E	AP2E	14,711	798	0	187	99	62
13	UG LINES DEMAND	D	AP2D	582	29	0	8	4	3
14	UG LINES ENERGY	E	AP2E	528	29	0	7	4	2
15									
16	SERVICES - OH - DEMAND	C	C02	1,860	92	256	0	0	8
17	SERVICES - OH - ENERGY	C	E02	1,584	86	267	0	0	0
18	SERVICES - UG - DEMAND	C	C02	4,186	206	576	0	0	18
19	SERVICES - UG - ENERGY	C	E02	3,564	193	602	0	0	0
20									
21	METER & METER INSTALLATIONS	C	S01	15,256	292	414	0	0	111
22	INSTALL. ON CUSTR PREMISES	C	C03	0	0	0	0	0	0
23	STREET LIGHTING	C	C04	0	0	0	8,497	4,566	0
24	CUSTOMER ACCOUNTING	C	S02	1,106	25	12	3	83	16
25	UNCOLLECTIBLES	R	S03	0	0	0	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	E01	1,057	57	179	13	7	4
27	REVENUES	R	R99	0	0	0	0	0	0
28				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		96,285	4,746	8,755	1,346	723	423
30	TOTAL ENERGY	E		84,721	4,597	9,295	1,079	571	359
31	TOTAL CUSTOMER	C		27,556	894	2,128	8,500	4,649	153
32	TOTAL REVENUE	R		0	0	0	0	0	0
33				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL			208,563	10,237	20,178	10,925	5,943	935
				===========	===========	===========	===========	===========	===========

				SC7 PRIMARY T.O.U. (17)	SC7 SEP MET SP HTG (18)	SC7 HV TOD (19)
	DEPRECIATION & AMORTIZATION					
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	1,457	105	305
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	1,712	55	462
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	13,932	1,004	0
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	16,610	537	0
5						
6	TRANSFORMERS - OH - DEMAND	D	AP2D	0	0	0
7	TRANSFORMERS - OH - ENERGY	E	AP2E	0	0	0
8	TRANSFORMERS - UG - DEMAND	D	AP2D	0	0	0
9	TRANSFORMERS - UG - ENERGY	E	AP2E	0	0	0
10						
11	OH LINES DEMAND	D	AP2D	0	0	0
12	OH LINES ENERGY	E	AP2E	0	0	0
13	UG LINES DEMAND	D	AP2D	0	0	0
14	UG LINES ENERGY	E	AP2E	0	0	0
15						
16	SERVICES - OH - DEMAND	C	C02	450	32	0
17	SERVICES - OH - ENERGY	C	E02	537	17	0
18	SERVICES - UG - DEMAND	C	C02	1,013	73	0
19	SERVICES - UG - ENERGY	C	E02	1,210	39	0
20						
21	METER & METER INSTALLATIONS	C	S01	232	110	73
22	INSTALL. ON CUSTR PREMISES	C	C03	1,179	377	0
23	STREET LIGHTING	C	C04	0	0	0
24	CUSTOMER ACCOUNTING	C	S02	6	0	0
25	UNCOLLECTIBLES	R	S03	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	E01	359	12	97
27	REVENUES	R	R99	0	0	0
28				-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		15,389	1,109	305
30	TOTAL ENERGY	E		18,682	603	559
31	TOTAL CUSTOMER	C		4,627	649	73
32	TOTAL REVENUE	R		0	0	0
33				-------------------	-------------------	-------------------
34	TOTAL			38,698	2,361	937
				===========	===========	===========

				TOTAL COMPANY (1)	TOTAL RESIDENTIAL (2)	TOTAL C&I (3)	MUNICIPAL LIGHTING (4)	PRIVATE LIGHTING (5)
	PROPERTY TAXES							
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	21,715	12,317	7,332	86	73
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	16,381	7,631	6,352	66	56
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	179,937	103,549	61,641	722	615
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	135,742	65,111	54,196	560	482
5								
6	TRANSFORMERS - OH - DEMAND	D	AP2D	22,975	14,906	7,877	104	89
7	TRANSFORMERS - OH - ENERGY	E	AP2E	17,332	10,009	7,163	86	74
8	TRANSFORMERS - UG - DEMAND	D	AP2D	13,574	8,807	4,654	61	52
9	TRANSFORMERS - UG - ENERGY	E	AP2E	10,240	5,914	4,232	51	44
10								
11	OH LINES DEMAND	D	AP2D	42,631	27,658	14,616	193	164
12	OH LINES ENERGY	E	AP2E	32,160	18,572	13,291	160	137
13	UG LINES DEMAND	D	AP2D	1,986	1,289	681	9	8
14	UG LINES ENERGY	E	AP2E	1,498	865	619	7	6
15								
16	SERVICES - OH - DEMAND	C	C02	5,976	3,460	2,060	0	8
17	SERVICES - OH - ENERGY	C	E02	4,508	2,179	1,814	0	0
18	SERVICES - UG - DEMAND	C	C02	14,891	8,623	5,133	0	19
19	SERVICES - UG - ENERGY	C	E02	11,234	5,430	4,520	0	0
20								
21	METER & METER INSTALLATIONS	C	S01	16,104	10,558	5,373	0	36
22	INSTALL. ON CUSTR PREMISES	C	C03	1,023	0	0	0	0
23	STREET LIGHTING	C	C04	8,332	0	0	5,420	2,912
24	CUSTOMER ACCOUNTING	C	S02	2,521	2,194	302	1	22
25	UNCOLLECTIBLES	R	S03	0	0	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	E01	753	351	292	3	3
27	REVENUES	R	R99	0	0	0	0	0
28				-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		282,818	168,526	96,801	1,175	1,001
30	TOTAL ENERGY	E		214,108	108,454	86,145	932	803
31	TOTAL CUSTOMER	C		64,588	32,445	19,202	5,421	2,997
32	TOTAL REVENUE	R		0	0	0	0	0
33				-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL			561,514	309,425	202,148	7,528	4,801
				===========	===========	===========	===========	===========

				TOTAL PRIMARY (6)	RESID SC1 GENERAL (7)	RESID SC3 T.O.U. (8)	RESID SC5 W/ SP HTG (9)	C&I SC2 SEC NON DEM (10)
	PROPERTY TAXES							
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	1,906	12,151	3	163	35
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	2,276	7,472	3	157	54
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	13,409	102,152	28	1,369	295
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	15,394	63,748	24	1,338	457
5								
6	TRANSFORMERS - OH - DEMAND	D	AP2D	0	14,705	4	197	70
7	TRANSFORMERS - OH - ENERGY	E	AP2E	0	9,800	4	206	42
8	TRANSFORMERS - UG - DEMAND	D	AP2D	0	8,688	2	116	42
9	TRANSFORMERS - UG - ENERGY	E	AP2E	0	5,790	2	122	25
10								
11	OH LINES DEMAND	D	AP2D	0	27,285	8	366	130
12	OH LINES ENERGY	E	AP2E	0	18,183	7	382	79
13	UG LINES DEMAND	D	AP2D	0	1,271	0	17	6
14	UG LINES ENERGY	E	AP2E	0	847	0	18	4
15								
16	SERVICES - OH - DEMAND	C	C02	448	3,413	1	46	10
17	SERVICES - OH - ENERGY	C	E02	515	2,133	1	45	15
18	SERVICES - UG - DEMAND	C	C02	1,117	8,506	2	114	25
19	SERVICES - UG - ENERGY	C	E02	1,284	5,317	2	112	38
20								
21	METER & METER INSTALLATIONS	C	S01	136	10,182	16	359	155
22	INSTALL. ON CUSTR PREMISES	C	C03	1,023	0	0	0	0
23	STREET LIGHTING	C	C04	0	0	0	0	0
24	CUSTOMER ACCOUNTING	C	S02	1	2,135	1	59	46
25	UNCOLLECTIBLES	R	S03	0	0	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	E01	105	344	0	7	2
27	REVENUES	R	R99	0	0	0	0	0
28				-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		15,315	166,251	46	2,229	579
30	TOTAL ENERGY	E		17,774	106,184	41	2,229	663
31	TOTAL CUSTOMER	C		4,524	31,687	23	734	289
32	TOTAL REVENUE	R		0	0	0	0	0
33				-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL			37,613	304,122	110	5,192	1,530
				===========	===========	===========	===========	===========

				C&I SC2 SEC GEN SERV (11)	C&I SC2 SEC SPACE HTG (12)	C&I SC2 PRIMARY GEN (13)	SC4 MUNI STR LTG (14)	SC6 DUSK TO DAWN (15)	SC6 ENERGY LTG (16)
	PROPERTY TAXES								
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	6,148	303	846	86	46	27
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	5,150	279	870	66	35	22
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	51,683	2,548	7,115	722	388	227
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	43,935	2,384	7,420	560	296	186
5									
6	TRANSFORMERS - OH - DEMAND	D	AP2D	7,440	367	0	104	56	33
7	TRANSFORMERS - OH - ENERGY	E	AP2E	6,754	366	0	86	45	29
8	TRANSFORMERS - UG - DEMAND	D	AP2D	4,396	217	0	61	33	19
9	TRANSFORMERS - UG - ENERGY	E	AP2E	3,990	217	0	51	27	17
10									
11	OH LINES DEMAND	D	AP2D	13,805	681	0	193	104	61
12	OH LINES ENERGY	E	AP2E	12,532	680	0	160	84	53
13	UG LINES DEMAND	D	AP2D	643	32	0	9	5	3
14	UG LINES ENERGY	E	AP2E	584	32	0	7	4	2
15									
16	SERVICES - OH - DEMAND	C	C02	1,727	85	238	0	0	8
17	SERVICES - OH - ENERGY	C	E02	1,470	80	248	0	0	0
18	SERVICES - UG - DEMAND	C	C02	4,304	212	592	0	0	19
19	SERVICES - UG - ENERGY	C	E02	3,664	199	619	0	0	0
20									
21	METER & METER INSTALLATIONS	C	S01	4,987	95	135	0	0	36
22	INSTALL. ON CUSTR PREMISES	C	C03	0	0	0	0	0	0
23	STREET LIGHTING	C	C04	0	0	0	5,420	2,912	0
24	CUSTOMER ACCOUNTING	C	S02	248	6	3	1	19	3
25	UNCOLLECTIBLES	R	S03	0	0	0	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	E01	237	13	40	3	2	1
27	REVENUES	R	R99	0	0	0	0	0	0
28				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		84,114	4,146	7,961	1,175	631	370
30	TOTAL ENERGY	E		73,182	3,971	8,329	932	493	310
31	TOTAL CUSTOMER	C		16,400	677	1,835	5,421	2,931	66
32	TOTAL REVENUE	R		0	0	0	0	0	0
33				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL			173,697	8,794	18,126	7,528	4,055	746
				===========	===========	===========	===========	===========	===========

				SC7 PRIMARY T.O.U. (17)	SC7 SEP MET SP HTG (18)	SC7 HV TOD (19)
	PROPERTY TAXES					
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	1,488	107	312
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	1,748	56	471
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	12,507	901	0
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	14,912	482	0
5						
6	TRANSFORMERS - OH - DEMAND	D	AP2D	0	0	0
7	TRANSFORMERS - OH - ENERGY	E	AP2E	0	0	0
8	TRANSFORMERS - UG - DEMAND	D	AP2D	0	0	0
9	TRANSFORMERS - UG - ENERGY	E	AP2E	0	0	0
10						
11	OH LINES DEMAND	D	AP2D	0	0	0
12	OH LINES ENERGY	E	AP2E	0	0	0
13	UG LINES DEMAND	D	AP2D	0	0	0
14	UG LINES ENERGY	E	AP2E	0	0	0
15						
16	SERVICES - OH - DEMAND	C	C02	418	30	0
17	SERVICES - OH - ENERGY	C	E02	499	16	0
18	SERVICES - UG - DEMAND	C	C02	1,042	75	0
19	SERVICES - UG - ENERGY	C	E02	1,244	40	0
20						
21	METER & METER INSTALLATIONS	C	S01	76	36	24
22	INSTALL. ON CUSTR PREMISES	C	C03	775	248	0
23	STREET LIGHTING	C	C04	0	0	0
24	CUSTOMER ACCOUNTING	C	S02	1	0	0
25	UNCOLLECTIBLES	R	S03	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	E01	80	3	22
27	REVENUES	R	R99	0	0	0
28				-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		13,995	1,009	312
30	TOTAL ENERGY	E		16,740	541	493
31	TOTAL CUSTOMER	C		4,055	445	24
32	TOTAL REVENUE	R		0	0	0
33				-------------------	-------------------	-------------------
34	TOTAL			34,790	1,995	828
				===========	===========	===========

				TOTAL COMPANY (1)	TOTAL RESIDENTIAL (2)	TOTAL C&I (3)	MUNICIPAL LIGHTING (4)	PRIVATE LIGHTING (5)
	PAYROLL & MISC. TAXES							
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	25,419	14,418	8,583	101	86
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	19,176	8,933	7,436	77	66
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	226,960	130,610	77,750	911	776
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	171,215	82,126	68,359	706	608
5								
6	TRANSFORMERS - OH - DEMAND	D	AP2D	7,001	4,542	2,400	32	27
7	TRANSFORMERS - OH - ENERGY	E	AP2E	5,282	3,050	2,183	26	23
8	TRANSFORMERS - UG - DEMAND	D	AP2D	4,136	2,684	1,418	19	16
9	TRANSFORMERS - UG - ENERGY	E	AP2E	3,120	1,802	1,290	15	13
10								
11	OH LINES DEMAND	D	AP2D	124,681	80,891	42,745	564	480
12	OH LINES ENERGY	E	AP2E	94,057	54,317	38,871	467	402
13	UG LINES DEMAND	D	AP2D	909	590	312	4	4
14	UG LINES ENERGY	E	AP2E	686	396	283	3	3
15								
16	SERVICES - OH - DEMAND	C	C02	17,062	9,880	5,881	0	22
17	SERVICES - OH - ENERGY	C	E02	12,872	6,222	5,179	0	0
18	SERVICES - UG - DEMAND	C	C02	5,777	3,345	1,991	0	7
19	SERVICES - UG - ENERGY	C	E02	4,358	2,106	1,753	0	0
20								
21	METER & METER INSTALLATIONS	C	S01	15,250	9,999	5,088	0	34
22	INSTALL. ON CUSTR PREMISES	C	C03	312	0	0	0	0
23	STREET LIGHTING	C	C04	14,289	0	0	9,295	4,994
24	CUSTOMER ACCOUNTING	C	S02	209,306	182,181	25,100	60	1,843
25	UNCOLLECTIBLES	R	S03	0	0	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	E01	62,556	29,143	24,257	250	216
27	REVENUES	R	S06	1,676,956	781,239	650,270	6,714	5,782
28				-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		389,106	233,734	133,208	1,630	1,388
30	TOTAL ENERGY	E		356,092	179,768	142,679	1,545	1,331
31	TOTAL CUSTOMER	C		279,225	213,733	44,993	9,354	6,900
32	TOTAL REVENUE	R		1,676,956	781,239	650,270	6,714	5,782
33				-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL			2,701,379	1,408,474	971,149	19,243	15,401
				===========	===========	===========	===========	===========

				TOTAL PRIMARY (6)	RESID SC1 GENERAL (7)	RESID SC3 T.O.U. (8)	RESID SC5 W/ SP HTG (9)	C&I SC2 SEC NON DEM (10)
	PAYROLL & MISC. TAXES							
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	2,232	14,224	4	191	41
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	2,664	8,746	3	184	63
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	16,913	128,847	36	1,727	372
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	19,416	80,408	31	1,688	576
5								
6	TRANSFORMERS - OH - DEMAND	D	AP2D	0	4,481	1	60	21
7	TRANSFORMERS - OH - ENERGY	E	AP2E	0	2,986	1	63	13
8	TRANSFORMERS - UG - DEMAND	D	AP2D	0	2,647	1	35	13
9	TRANSFORMERS - UG - ENERGY	E	AP2E	0	1,764	1	37	8
10								
11	OH LINES DEMAND	D	AP2D	0	79,799	22	1,070	381
12	OH LINES ENERGY	E	AP2E	0	53,180	20	1,117	230
13	UG LINES DEMAND	D	AP2D	0	582	0	8	3
14	UG LINES ENERGY	E	AP2E	0	388	0	8	2
15								
16	SERVICES - OH - DEMAND	C	C02	1,279	9,747	3	131	28
17	SERVICES - OH - ENERGY	C	E02	1,471	6,092	2	128	44
18	SERVICES - UG - DEMAND	C	C02	433	3,300	1	44	10
19	SERVICES - UG - ENERGY	C	E02	498	2,062	1	43	15
20								
21	METER & METER INSTALLATIONS	C	S01	129	9,643	16	340	147
22	INSTALL. ON CUSTR PREMISES	C	C03	312	0	0	0	0
23	STREET LIGHTING	C	C04	0	0	0	0	0
24	CUSTOMER ACCOUNTING	C	S02	123	177,262	50	4,869	3,844
25	UNCOLLECTIBLES	R	S03	0	0	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	E01	8,690	28,533	11	599	204
27	REVENUES	R	S06	232,951	764,887	293	16,059	5,478
28				-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		19,144	230,579	64	3,091	832
30	TOTAL ENERGY	E		30,770	176,006	67	3,695	1,096
31	TOTAL CUSTOMER	C		4,245	208,105	72	5,556	4,087
32	TOTAL REVENUE	R		232,951	764,887	293	16,059	5,478
33				-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL			287,110	1,379,577	496	28,401	11,492
				===========	===========	===========	===========	===========

				C&I SC2 SEC GEN SERV (11)	C&I SC2 SEC SPACE HTG (12)	C&I SC2 PRIMARY GEN (13)	SC4 MUNI STR LTG (14)	SC6 DUSK TO DAWN (15)	SC6 ENERGY LTG (16)
	PAYROLL & MISC. TAXES								
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	7,196	355	991	101	54	32
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	6,028	327	1,018	77	41	26
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	65,190	3,214	8,975	911	489	287
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	55,417	3,007	9,359	706	373	235
5									
6	TRANSFORMERS - OH - DEMAND	D	AP2D	2,267	112	0	32	17	10
7	TRANSFORMERS - OH - ENERGY	E	AP2E	2,058	112	0	26	14	9
8	TRANSFORMERS - UG - DEMAND	D	AP2D	1,339	66	0	19	10	6
9	TRANSFORMERS - UG - ENERGY	E	AP2E	1,216	66	0	15	8	5
10									
11	OH LINES DEMAND	D	AP2D	40,374	1,990	0	564	303	177
12	OH LINES ENERGY	E	AP2E	36,652	1,989	0	467	247	155
13	UG LINES DEMAND	D	AP2D	294	15	0	4	2	1
14	UG LINES ENERGY	E	AP2E	267	14	0	3	2	1
15									
16	SERVICES - OH - DEMAND	C	C02	4,931	243	679	0	0	22
17	SERVICES - OH - ENERGY	C	E02	4,198	228	709	0	0	0
18	SERVICES - UG - DEMAND	C	C02	1,670	82	230	0	0	7
19	SERVICES - UG - ENERGY	C	E02	1,421	77	240	0	0	0
20									
21	METER & METER INSTALLATIONS	C	S01	4,723	90	128	0	0	34
22	INSTALL. ON CUSTR PREMISES	C	C03	0	0	0	0	0	0
23	STREET LIGHTING	C	C04	0	0	0	9,295	4,994	0
24	CUSTOMER ACCOUNTING	C	S02	20,570	467	219	60	1,553	290
25	UNCOLLECTIBLES	R	S03	0	0	0	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	E01	19,665	1,067	3,321	250	132	83
27	REVENUES	R	S06	527,163	28,603	89,026	6,714	3,551	2,231
28				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		116,661	5,751	9,965	1,630	876	513
30	TOTAL ENERGY	E		121,304	6,582	13,698	1,545	817	513
31	TOTAL CUSTOMER	C		37,513	1,188	2,205	9,354	6,547	353
32	TOTAL REVENUE	R		527,163	28,603	89,026	6,714	3,551	2,231
33				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL			802,640	42,123	114,893	19,243	11,791	3,611
				===========	===========	===========	===========	===========	===========

				SC7 PRIMARY T.O.U. (17)	SC7 SEP MET SP HTG (18)	SC7 HV TOD (19)
	PAYROLL & MISC. TAXES					
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	1,742	126	365
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	2,046	66	552
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	15,776	1,137	0
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	18,809	608	0
5						
6	TRANSFORMERS - OH - DEMAND	D	AP2D	0	0	0
7	TRANSFORMERS - OH - ENERGY	E	AP2E	0	0	0
8	TRANSFORMERS - UG - DEMAND	D	AP2D	0	0	0
9	TRANSFORMERS - UG - ENERGY	E	AP2E	0	0	0
10						
11	OH LINES DEMAND	D	AP2D	0	0	0
12	OH LINES ENERGY	E	AP2E	0	0	0
13	UG LINES DEMAND	D	AP2D	0	0	0
14	UG LINES ENERGY	E	AP2E	0	0	0
15						
16	SERVICES - OH - DEMAND	C	C02	1,193	86	0
17	SERVICES - OH - ENERGY	C	E02	1,425	46	0
18	SERVICES - UG - DEMAND	C	C02	404	29	0
19	SERVICES - UG - ENERGY	C	E02	482	16	0
20						
21	METER & METER INSTALLATIONS	C	S01	72	34	23
22	INSTALL. ON CUSTR PREMISES	C	C03	236	76	0
23	STREET LIGHTING	C	C04	0	0	0
24	CUSTOMER ACCOUNTING	C	S02	111	9	3
25	UNCOLLECTIBLES	R	S03	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	E01	6,674	216	1,800
27	REVENUES	R	S06	178,922	5,779	48,250
28				-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		17,517	1,262	365
30	TOTAL ENERGY	E		27,529	889	2,352
31	TOTAL CUSTOMER	C		3,924	295	26
32	TOTAL REVENUE	R		178,922	5,779	48,250
33				-------------------	-------------------	-------------------
34	TOTAL			227,892	8,226	50,993
				===========	===========	===========

			TOTAL COMPANY (1)	TOTAL RESIDENTIAL (2)	TOTAL C&I (3)	MUNICIPAL LIGHTING (4)	PRIVATE LIGHTING (5)
	TOTAL OPERATING EXPENSES						
1	HIGH TENSION ≥ 69 KV - DEMAND	D	1,406,785	797,959	475,013	5,566	4,740
2	HIGH TENSION ≥ 69 KV - ENERGY	E	1,061,259	494,406	411,522	4,249	3,659
3	HIGH TENSION < 69 KV - DEMAND	D	12,371,277	7,119,386	4,238,060	49,656	42,288
4	HIGH TENSION < 69 KV - ENERGY	E	9,332,718	4,476,609	3,726,138	38,472	33,134
5							
6	TRANSFORMERS - OH - DEMAND	D	692,005	448,960	237,246	3,131	2,667
7	TRANSFORMERS - OH - ENERGY	E	522,039	301,473	215,744	2,591	2,231
8	TRANSFORMERS - UG - DEMAND	D	408,854	265,257	140,171	1,850	1,576
9	TRANSFORMERS - UG - ENERGY	E	308,434	178,118	127,467	1,531	1,318
10							
11	OH LINES DEMAND	D	5,942,553	3,855,422	2,037,340	26,890	22,901
12	OH LINES ENERGY	E	4,482,979	2,588,881	1,852,687	22,249	19,162
13	UG LINES DEMAND	D	68,448	44,408	23,467	310	264
14	UG LINES ENERGY	E	51,636	29,819	21,340	256	221
15							
16	SERVICES - OH - DEMAND	C	814,817	471,819	280,867	0	1,035
17	SERVICES - OH - ENERGY	C	614,687	297,125	247,314	0	0
18	SERVICES - UG - DEMAND	C	470,166	272,249	162,066	0	597
19	SERVICES - UG - ENERGY	C	354,686	171,447	142,705	0	0
20							
21	METER & METER INSTALLATIONS	C	923,989	605,814	308,305	0	2,078
22	INSTALL. ON CUSTR PREMISES	C	29,256	0	0	0	0
23	STREET LIGHTING	C	737,100	0	0	479,470	257,630
24	CUSTOMER ACCOUNTING	C	7,925,461	6,898,376	950,408	2,255	69,770
25	UNCOLLECTIBLES	R	611,945	339,347	223,087	8,240	4,466
26	CUSTOMER SERVICE AND 901 & 905	E	2,128,296	991,503	825,285	8,521	7,339
27	REVENUES	R	1,676,956	781,239	650,270	6,714	5,782
28			-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D	20,889,923	12,531,392	7,151,297	87,403	74,435
30	TOTAL ENERGY	E	17,887,361	9,060,810	7,180,182	77,869	67,064
31	TOTAL CUSTOMER	C	11,870,161	8,716,831	2,091,666	481,725	331,111
32	TOTAL REVENUE	R	2,288,901	1,120,585	873,357	14,954	10,249
33			-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL		52,936,345	31,429,619	17,296,501	661,951	482,859
			===========	===========	===========	===========	===========

			TOTAL PRIMARY (6)	RESID SC1 GENERAL (7)	RESID SC3 T.O.U. (8)	RESID SC5 W/ SP HTG (9)	C&I SC2 SEC NON DEM (10)
	TOTAL OPERATING EXPENSES						
1	HIGH TENSION ≥ 69 KV - DEMAND	D	123,509	787,188	218	10,553	2,276
2	HIGH TENSION ≥ 69 KV - ENERGY	E	147,423	484,058	186	10,163	3,467
3	HIGH TENSION < 69 KV - DEMAND	D	921,886	7,023,287	1,945	94,154	20,304
4	HIGH TENSION < 69 KV - ENERGY	E	1,058,364	4,382,912	1,680	92,018	31,391
5							
6	TRANSFORMERS - OH - DEMAND	D	0	442,900	123	5,938	2,117
7	TRANSFORMERS - OH - ENERGY	E	0	295,163	113	6,197	1,279
8	TRANSFORMERS - UG - DEMAND	D	0	261,677	72	3,508	1,251
9	TRANSFORMERS - UG - ENERGY	E	0	174,390	67	3,661	756
10							
11	OH LINES DEMAND	D	0	3,803,380	1,053	50,988	18,178
12	OH LINES ENERGY	E	0	2,534,695	971	53,215	10,981
13	UG LINES DEMAND	D	0	43,808	12	587	209
14	UG LINES ENERGY	E	0	29,195	11	613	126
15							
16	SERVICES - OH - DEMAND	C	61,096	465,451	129	6,240	1,346
17	SERVICES - OH - ENERGY	C	70,247	290,906	111	6,107	2,084
18	SERVICES - UG - DEMAND	C	35,253	268,574	74	3,601	776
19	SERVICES - UG - ENERGY	C	40,534	167,859	64	3,524	1,202
20							
21	METER & METER INSTALLATIONS	C	7,792	584,251	941	20,621	8,893
22	INSTALL. ON CUSTR PREMISES	C	29,256	0	0	0	0
23	STREET LIGHTING	C	0	0	0	0	0
24	CUSTOMER ACCOUNTING	C	4,651	6,712,120	1,879	184,376	145,541
25	UNCOLLECTIBLES	R	36,805	332,233	96	7,018	3,355
26	CUSTOMER SERVICE AND 901 & 905	E	295,648	970,751	372	20,381	6,953
27	REVENUES	R	232,951	764,887	293	16,059	5,478
28			-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D	1,045,395	12,362,240	3,423	165,728	44,335
30	TOTAL ENERGY	E	1,501,435	8,871,163	3,400	186,247	54,952
31	TOTAL CUSTOMER	C	248,829	8,489,162	3,199	224,470	159,843
32	TOTAL REVENUE	R	269,756	1,097,120	389	23,077	8,833
33			-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL		3,065,415	30,819,686	10,411	599,522	267,963
			===========	===========	===========	===========	===========

			C&I SC2 SEC GEN SERV (11)	C&I SC2 SEC SPACE HTG (12)	C&I SC2 PRIMARY GEN (13)	SC4 MUNI STR LTG (14)	SC6 DUSK TO DAWN (15)	SC6 ENERGY LTG (16)
	TOTAL OPERATING EXPENSES							
1	HIGH TENSION ≥ 69 KV - DEMAND	D	398,274	19,633	54,830	5,566	2,989	1,751
2	HIGH TENSION ≥ 69 KV - ENERGY	E	333,614	18,101	56,340	4,249	2,247	1,412
3	HIGH TENSION < 69 KV - DEMAND	D	3,553,401	175,165	489,189	49,656	26,670	15,619
4	HIGH TENSION < 69 KV - ENERGY	E	3,020,719	163,899	510,129	38,472	20,349	12,786
5								
6	TRANSFORMERS - OH - DEMAND	D	224,083	11,046	0	3,131	1,682	985
7	TRANSFORMERS - OH - ENERGY	E	203,427	11,038	0	2,591	1,370	861
8	TRANSFORMERS - UG - DEMAND	D	132,394	6,526	0	1,850	994	582
9	TRANSFORMERS - UG - ENERGY	E	120,190	6,521	0	1,531	810	509
10								
11	OH LINES DEMAND	D	1,924,304	94,859	0	26,890	14,443	8,458
12	OH LINES ENERGY	E	1,746,921	94,785	0	22,249	11,768	7,394
13	UG LINES DEMAND	D	22,165	1,093	0	310	166	97
14	UG LINES ENERGY	E	20,122	1,092	0	256	136	85
15								
16	SERVICES - OH - DEMAND	C	235,493	11,609	32,420	0	0	1,035
17	SERVICES - OH - ENERGY	C	200,494	10,878	33,859	0	0	0
18	SERVICES - UG - DEMAND	C	135,884	6,698	18,707	0	0	597
19	SERVICES - UG - ENERGY	C	115,689	6,277	19,537	0	0	0
20								
21	METER & METER INSTALLATIONS	C	286,165	5,472	7,774	0	0	2,078
22	INSTALL. ON CUSTR PREMISES	C	0	0	0	0	0	0
23	STREET LIGHTING	C	0	0	0	479,470	257,630	0
24	CUSTOMER ACCOUNTING	C	778,887	17,696	8,284	2,255	58,798	10,973
25	UNCOLLECTIBLES	R	188,055	7,834	23,843	8,240	3,528	938
26	CUSTOMER SERVICE AND 901 & 905	E	669,045	36,301	112,986	8,521	4,507	2,832
27	REVENUES	R	527,163	28,603	89,026	6,714	3,551	2,231
28			------------------	------------------	------------------	------------------	------------------	------------------
29	TOTAL DEMAND	D	6,254,622	308,322	544,019	87,403	46,943	27,492
30	TOTAL ENERGY	E	6,114,037	331,737	679,455	77,869	41,186	25,878
31	TOTAL CUSTOMER	C	1,752,612	58,631	120,580	481,725	316,428	14,683
32	TOTAL REVENUE	R	715,218	36,437	112,868	14,954	7,079	3,170
33			------------------	------------------	------------------	------------------	------------------	------------------
34	TOTAL		14,836,489	735,127	1,456,923	661,951	411,636	71,222
			===========	===========	===========	===========	===========	===========

			SC7 PRIMARY T.O.U. (17)	SC7 SEP MET SP HTG (18)	SC7 HV TOD (19)
	TOTAL OPERATING EXPENSES				
1	HIGH TENSION ≥ 69 KV - DEMAND	D	96,381	6,946	20,181
2	HIGH TENSION ≥ 69 KV - ENERGY	E	113,230	3,658	30,535
3	HIGH TENSION < 69 KV - DEMAND	D	859,913	61,974	0
4	HIGH TENSION < 69 KV - ENERGY	E	1,025,247	33,117	0
5					
6	TRANSFORMERS - OH - DEMAND	D	0	0	0
7	TRANSFORMERS - OH - ENERGY	E	0	0	0
8	TRANSFORMERS - UG - DEMAND	D	0	0	0
9	TRANSFORMERS - UG - ENERGY	E	0	0	0
10					
11	OH LINES DEMAND	D	0	0	0
12	OH LINES ENERGY	E	0	0	0
13	UG LINES DEMAND	D	0	0	0
14	UG LINES ENERGY	E	0	0	0
15					
16	SERVICES - OH - DEMAND	C	56,989	4,107	0
17	SERVICES - OH - ENERGY	C	68,049	2,198	0
18	SERVICES - UG - DEMAND	C	32,884	2,370	0
19	SERVICES - UG - ENERGY	C	39,265	1,268	0
20					
21	METER & METER INSTALLATIONS	C	4,359	2,060	1,373
22	INSTALL. ON CUSTR PREMISES	C	22,170	7,087	0
23	STREET LIGHTING	C	0	0	0
24	CUSTOMER ACCOUNTING	C	4,192	328	132
25	UNCOLLECTIBLES	R	33,415	1,786	1,604
26	CUSTOMER SERVICE AND 901 & 905	E	227,077	7,335	61,236
27	REVENUES	R	178,922	5,779	48,250
28			-------------------	-------------------	-------------------
29	TOTAL DEMAND	D	956,294	68,920	20,181
30	TOTAL ENERGY	E	1,365,554	44,110	91,771
31	TOTAL CUSTOMER	C	227,907	19,418	1,505
32	TOTAL REVENUE	R	212,336	7,566	49,854
33			-------------------	-------------------	-------------------
34	TOTAL		2,762,091	140,013	163,311
			===========	===========	===========

				TOTAL COMPANY (1)	TOTAL RESIDENTIAL (2)	TOTAL C&I (3)	MUNICIPAL LIGHTING (4)	PRIVATE LIGHTING (5)
	OPERATING REVENUES							
1	REVENUES FROM SALES	R	R01	65,010,326	36,050,702	23,699,810	875,398	474,466
2	OTHER ELECTRIC REVENUES	R	R02	150,527	10,071	49,645	15,114	8,192
3				-------------------	-------------------	-------------------	-------------------	-------------------
4	TOTAL OPERATING REVENUES			65,160,854	36,060,774	23,749,455	890,512	482,657
				===========	===========	===========	===========	===========

				TOTAL PRIMARY (6)	RESID SC1 GENERAL (7)	RESID SC3 T.O.U. (8)	RESID SC5 W/ SP HTG (9)	C&I SC2 SEC NON DEM (10)
	OPERATING REVENUES							
1	REVENUES FROM SALES	R	R01	3,909,950	35,294,980	10,155	745,567	356,439
2	OTHER ELECTRIC REVENUES	R	R02	67,505	9,860	3	208	100
3				-------------------	-------------------	-------------------	-------------------	-------------------
4	TOTAL OPERATING REVENUES			3,977,456	35,304,841	10,158	745,775	356,539
				===========	===========	===========	===========	===========

				C&I SC2 SEC GEN SERV (11)	C&I SC2 SEC SPACE HTG (12)	C&I SC2 PRIMARY GEN (13)	SC4 MUNI STR LTG (14)	SC6 DUSK TO DAWN (15)	SC6 ENERGY LTG (16)
	OPERATING REVENUES								
1	REVENUES FROM SALES	R	R01	19,978,153	832,258	2,532,959	875,398	374,775	99,691
2	OTHER ELECTRIC REVENUES	R	R02	5,581	233	43,732	15,114	6,470	1,721
3				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
4	TOTAL OPERATING REVENUES			19,983,735	832,491	2,576,690	890,512	381,245	101,412
				===========	===========	===========	===========	===========	===========

				SC7 PRIMARY T.O.U. (17)	SC7 SEP MET SP HTG (18)	SC7 HV TOD (19)
	OPERATING REVENUES					
1	REVENUES FROM SALES	R	R01	3,549,826	189,750	170,374
2	OTHER ELECTRIC REVENUES	R	R02	61,288	3,276	2,942
3				-------------------	-------------------	-------------------
4	TOTAL OPERATING REVENUES			3,611,114	193,026	173,315
				===========	===========	===========

				TOTAL COMPANY (1)	TOTAL RESIDENTIAL (2)	TOTAL C&I (3)	MUNICIPAL LIGHTING (4)	PRIVATE LIGHTING (5)
	FIT ADJUSTMENTS							
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	(78,625)	(44,598)	(26,549)	(311)	(265)
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	(59,314)	(27,632)	(23,000)	(237)	(205)
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	(642,351)	(369,658)	(220,052)	(2,578)	(2,196)
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	(484,581)	(232,438)	(193,471)	(1,998)	(1,720)
5								
6	TRANSFORMERS - OH - DEMAND	D	AP2D	(80,443)	(52,190)	(27,579)	(364)	(310)
7	TRANSFORMERS - OH - ENERGY	E	AP2E	(60,685)	(35,045)	(25,079)	(301)	(259)
8	TRANSFORMERS - UG - DEMAND	D	AP2D	(47,528)	(30,835)	(16,294)	(215)	(183)
9	TRANSFORMERS - UG - ENERGY	E	AP2E	(35,854)	(20,705)	(14,818)	(178)	(153)
10								
11	OH LINES DEMAND	D	AP2D	(193,647)	(125,634)	(66,390)	(876)	(746)
12	OH LINES ENERGY	E	AP2E	(146,084)	(84,362)	(60,372)	(725)	(624)
13	UG LINES DEMAND	D	AP2D	(6,428)	(4,170)	(2,204)	(29)	(25)
14	UG LINES ENERGY	E	AP2E	(4,849)	(2,800)	(2,004)	(24)	(21)
15								
16	SERVICES - OH - DEMAND	C	C02	(28,429)	(16,462)	(9,800)	0	(36)
17	SERVICES - OH - ENERGY	C	E02	(21,447)	(10,367)	(8,629)	0	0
18	SERVICES - UG - DEMAND	C	C02	(59,655)	(34,543)	(20,563)	0	(76)
19	SERVICES - UG - ENERGY	C	E02	(45,003)	(21,753)	(18,107)	0	0
20								
21	METER & METER INSTALLATIONS	C	S01	(50,890)	(33,366)	(16,980)	0	(114)
22	INSTALL. ON CUSTR PREMISES	C	C03	(3,291)	0	0	0	0
23	STREET LIGHTING	C	C04	(42,617)	0	0	(27,721)	(14,895)
24	CUSTOMER ACCOUNTING	C	S02	(73,554)	(64,022)	(8,820)	(21)	(648)
25	UNCOLLECTIBLES	R	S03	0	0	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	E01	61,299	28,557	23,770	245	211
27	REVENUES	R	R99	0	0	0	0	0
28				-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		(1,049,021)	(627,086)	(359,067)	(4,374)	(3,725)
30	TOTAL ENERGY	E		(730,068)	(374,426)	(294,975)	(3,218)	(2,771)
31	TOTAL CUSTOMER	C		(324,886)	(180,514)	(82,899)	(27,742)	(15,769)
32	TOTAL REVENUE	R		0	0	0	0	0
33				-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL			(2,103,974)	(1,182,026)	(736,941)	(35,334)	(22,265)
				===========	===========	===========	===========	===========

				TOTAL PRIMARY (6)	RESID SC1 GENERAL (7)	RESID SC3 T.O.U. (8)	RESID SC5 W/ SP HTG (9)	C&I SC2 SEC NON DEM (10)
	FIT ADJUSTMENTS							
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	(6,903)	(43,996)	(12)	(590)	(127)
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	(8,239)	(27,054)	(10)	(568)	(194)
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	(47,867)	(364,668)	(101)	(4,889)	(1,054)
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	(54,953)	(227,573)	(87)	(4,778)	(1,630)
5								
6	TRANSFORMERS - OH - DEMAND	D	AP2D	0	(51,485)	(14)	(690)	(246)
7	TRANSFORMERS - OH - ENERGY	E	AP2E	0	(34,312)	(13)	(720)	(149)
8	TRANSFORMERS - UG - DEMAND	D	AP2D	0	(30,419)	(8)	(408)	(145)
9	TRANSFORMERS - UG - ENERGY	E	AP2E	0	(20,272)	(8)	(426)	(88)
10								
11	OH LINES DEMAND	D	AP2D	0	(123,939)	(34)	(1,662)	(592)
12	OH LINES ENERGY	E	AP2E	0	(82,597)	(32)	(1,734)	(358)
13	UG LINES DEMAND	D	AP2D	0	(4,114)	(1)	(55)	(20)
14	UG LINES ENERGY	E	AP2E	0	(2,742)	(1)	(58)	(12)
15								
16	SERVICES - OH - DEMAND	C	C02	(2,132)	(16,240)	(4)	(218)	(47)
17	SERVICES - OH - ENERGY	C	E02	(2,451)	(10,150)	(4)	(213)	(73)
18	SERVICES - UG - DEMAND	C	C02	(4,473)	(34,077)	(9)	(457)	(99)
19	SERVICES - UG - ENERGY	C	E02	(5,143)	(21,298)	(8)	(447)	(153)
20								
21	METER & METER INSTALLATIONS	C	S01	(429)	(32,178)	(52)	(1,136)	(490)
22	INSTALL. ON CUSTR PREMISES	C	C03	(3,291)	0	0	0	0
23	STREET LIGHTING	C	C04	0	0	0	0	0
24	CUSTOMER ACCOUNTING	C	S02	(43)	(62,293)	(17)	(1,711)	(1,351)
25	UNCOLLECTIBLES	R	S03	0	0	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	E01	8,515	27,960	11	587	200
27	REVENUES	R	R99	0	0	0	0	0
28				-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		(54,770)	(618,621)	(171)	(8,293)	(2,185)
30	TOTAL ENERGY	E		(54,677)	(366,589)	(140)	(7,696)	(2,230)
31	TOTAL CUSTOMER	C		(17,962)	(176,237)	(95)	(4,182)	(2,211)
32	TOTAL REVENUE	R		0	0	0	0	0
33				-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL			(127,409)	(1,161,447)	(407)	(20,171)	(6,626)
				===========	===========	===========	===========	===========

				C&I SC2 SEC GEN SERV (11)	C&I SC2 SEC SPACE HTG (12)	C&I SC2 PRIMARY GEN (13)	SC4 MUNI STR LTG (14)	SC6 DUSK TO DAWN (15)	SC6 ENERGY LTG (16)
	FIT ADJUSTMENTS								
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	(22,260)	(1,097)	(3,064)	(311)	(167)	(98)
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	(18,646)	(1,012)	(3,149)	(237)	(126)	(79)
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	(184,502)	(9,095)	(25,400)	(2,578)	(1,385)	(811)
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	(156,844)	(8,510)	(26,487)	(1,998)	(1,057)	(664)
5									
6	TRANSFORMERS - OH - DEMAND	D	AP2D	(26,049)	(1,284)	0	(364)	(196)	(114)
7	TRANSFORMERS - OH - ENERGY	E	AP2E	(23,648)	(1,283)	0	(301)	(159)	(100)
8	TRANSFORMERS - UG - DEMAND	D	AP2D	(15,390)	(759)	0	(215)	(116)	(68)
9	TRANSFORMERS - UG - ENERGY	E	AP2E	(13,972)	(758)	0	(178)	(94)	(59)
10									
11	OH LINES DEMAND	D	AP2D	(62,706)	(3,091)	0	(876)	(471)	(276)
12	OH LINES ENERGY	E	AP2E	(56,926)	(3,089)	0	(725)	(383)	(241)
13	UG LINES DEMAND	D	AP2D	(2,081)	(103)	0	(29)	(16)	(9)
14	UG LINES ENERGY	E	AP2E	(1,890)	(103)	0	(24)	(13)	(8)
15									
16	SERVICES - OH - DEMAND	C	C02	(8,216)	(405)	(1,131)	0	0	(36)
17	SERVICES - OH - ENERGY	C	E02	(6,995)	(380)	(1,181)	0	0	0
18	SERVICES - UG - DEMAND	C	C02	(17,241)	(850)	(2,374)	0	0	(76)
19	SERVICES - UG - ENERGY	C	E02	(14,679)	(796)	(2,479)	0	0	0
20									
21	METER & METER INSTALLATIONS	C	S01	(15,761)	(301)	(428)	0	0	(114)
22	INSTALL. ON CUSTR PREMISES	C	C03	0	0	0	0	0	0
23	STREET LIGHTING	C	C04	0	0	0	(27,721)	(14,895)	0
24	CUSTOMER ACCOUNTING	C	S02	(7,229)	(164)	(77)	(21)	(546)	(102)
25	UNCOLLECTIBLES	R	S03	0	0	0	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	E01	19,270	1,046	3,254	245	130	82
27	REVENUES	R	R99	0	0	0	0	0	0
28				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		(312,989)	(15,429)	(28,465)	(4,374)	(2,349)	(1,376)
30	TOTAL ENERGY	E		(252,655)	(13,709)	(26,382)	(3,218)	(1,702)	(1,069)
31	TOTAL CUSTOMER	C		(70,121)	(2,897)	(7,670)	(27,742)	(15,441)	(328)
32	TOTAL REVENUE	R		0	0	0	0	0	0
33				-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL			(635,765)	(32,034)	(62,516)	(35,334)	(19,492)	(2,773)
				===========	===========	===========	===========	===========	===========

				SC7 PRIMARY T.O.U. (17)	SC7 SEP MET SP HTG (18)	SC7 HV TOD (19)
	FIT ADJUSTMENTS					
1	HIGH TENSION ≥ 69 KV - DEMAND	D	D02	(5,387)	(388)	(1,128)
2	HIGH TENSION ≥ 69 KV - ENERGY	E	E01	(6,328)	(204)	(1,707)
3	HIGH TENSION < 69 KV - DEMAND	D	D02A	(44,649)	(3,218)	0
4	HIGH TENSION < 69 KV - ENERGY	E	E01A	(53,234)	(1,720)	0
5						
6	TRANSFORMERS - OH - DEMAND	D	AP2D	0	0	0
7	TRANSFORMERS - OH - ENERGY	E	AP2E	0	0	0
8	TRANSFORMERS - UG - DEMAND	D	AP2D	0	0	0
9	TRANSFORMERS - UG - ENERGY	E	AP2E	0	0	0
10						
11	OH LINES DEMAND	D	AP2D	0	0	0
12	OH LINES ENERGY	E	AP2E	0	0	0
13	UG LINES DEMAND	D	AP2D	0	0	0
14	UG LINES ENERGY	E	AP2E	0	0	0
15						
16	SERVICES - OH - DEMAND	C	C02	(1,988)	(143)	0
17	SERVICES - OH - ENERGY	C	E02	(2,374)	(77)	0
18	SERVICES - UG - DEMAND	C	C02	(4,172)	(301)	0
19	SERVICES - UG - ENERGY	C	E02	(4,982)	(161)	0
20						
21	METER & METER INSTALLATIONS	C	S01	(240)	(113)	(76)
22	INSTALL. ON CUSTR PREMISES	C	C03	(2,494)	(797)	0
23	STREET LIGHTING	C	C04	0	0	0
24	CUSTOMER ACCOUNTING	C	S02	(39)	(3)	(1)
25	UNCOLLECTIBLES	R	S03	0	0	0
26	CUSTOMER SERVICE AND 901 & 905	E	E01	6,540	211	1,764
27	REVENUES	R	R99	0	0	0
28				-------------------	-------------------	-------------------
29	TOTAL DEMAND	D		(50,036)	(3,606)	(1,128)
30	TOTAL ENERGY	E		(53,022)	(1,713)	57
31	TOTAL CUSTOMER	C		(16,290)	(1,595)	(77)
32	TOTAL REVENUE	R		0	0	0
33				-------------------	-------------------	-------------------
34	TOTAL			(119,347)	(6,914)	(1,148)
				===========	===========	===========

			TOTAL COMPANY (1)	TOTAL RESIDENTIAL (2)	TOTAL C&I (3)	MUNICIPAL LIGHTING (4)	PRIVATE LIGHTING (5)
	FEDERAL INCOME TAX COMPUTATION						
1	HIGH TENSION ≥ 69 KV - DEMAND	D	(374,050)	(212,169)	(126,301)	(1,480)	(1,260)
2	HIGH TENSION ≥ 69 KV - ENERGY	E	(282,178)	(131,458)	(109,420)	(1,130)	(973)
3	HIGH TENSION < 69 KV - DEMAND	D	(3,240,319)	(1,864,729)	(1,110,044)	(13,006)	(11,076)
4	HIGH TENSION < 69 KV - ENERGY	E	(2,444,451)	(1,172,526)	(975,960)	(10,077)	(8,679)
5							
6	TRANSFORMERS - OH - DEMAND	D	(225,764)	(146,471)	(77,401)	(1,022)	(870)
7	TRANSFORMERS - OH - ENERGY	E	(170,313)	(98,354)	(70,385)	(845)	(728)
8	TRANSFORMERS - UG - DEMAND	D	(133,387)	(86,539)	(45,730)	(604)	(514)
9	TRANSFORMERS - UG - ENERGY	E	(100,625)	(58,110)	(41,586)	(499)	(430)
10							
11	OH LINES DEMAND	D	(1,441,583)	(935,273)	(494,231)	(6,523)	(5,555)
12	OH LINES ENERGY	E	(1,087,510)	(628,027)	(449,437)	(5,397)	(4,648)
13	UG LINES DEMAND	D	(20,802)	(13,496)	(7,132)	(94)	(80)
14	UG LINES ENERGY	E	(15,693)	(9,062)	(6,485)	(78)	(67)
15							
16	SERVICES - OH - DEMAND	C	(199,541)	(115,544)	(68,782)	0	(253)
17	SERVICES - OH - ENERGY	C	(150,531)	(72,763)	(60,565)	0	0
18	SERVICES - UG - DEMAND	C	(158,390)	(91,716)	(54,597)	0	(201)
19	SERVICES - UG - ENERGY	C	(119,487)	(57,757)	(48,075)	0	0
20							
21	METER & METER INSTALLATIONS	C	(244,927)	(160,587)	(81,724)	0	(551)
22	INSTALL. ON CUSTR PREMISES	C	(9,435)	0	0	0	0
23	STREET LIGHTING	C	(197,408)	0	0	(128,410)	(68,998)
24	CUSTOMER ACCOUNTING	C	(1,737,901)	(1,512,681)	(208,406)	(494)	(15,299)
25	UNCOLLECTIBLES	R	(128,508)	(71,263)	(46,848)	(1,730)	(938)
26	CUSTOMER SERVICE AND 901 & 905	E	(385,643)	(179,658)	(149,540)	(1,544)	(1,330)
27	REVENUES	R	13,331,618	7,408,702	4,850,829	185,598	100,144
28			-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D	(5,435,905)	(3,258,678)	(1,860,839)	(22,728)	(19,356)
30	TOTAL ENERGY	E	(4,486,413)	(2,277,196)	(1,802,813)	(19,570)	(16,855)
31	TOTAL CUSTOMER	C	(2,817,620)	(2,011,048)	(522,149)	(128,904)	(85,302)
32	TOTAL REVENUE	R	13,203,110	7,337,440	4,803,981	183,867	99,206
33			-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL		463,172	(209,483)	618,179	12,664	(22,308)
			===========	===========	===========	===========	===========

			TOTAL PRIMARY (6)	RESID SC1 GENERAL (7)	RESID SC3 T.O.U. (8)	RESID SC5 W/ SP HTG (9)	C&I SC2 SEC NON DEM (10)
	FEDERAL INCOME TAX COMPUTATION						
1	HIGH TENSION ≥ 69 KV - DEMAND	D	(32,840)	(209,305)	(58)	(2,806)	(605)
2	HIGH TENSION ≥ 69 KV - ENERGY	E	(39,198)	(128,706)	(49)	(2,702)	(922)
3	HIGH TENSION < 69 KV - DEMAND	D	(241,463)	(1,839,559)	(509)	(24,661)	(5,318)
4	HIGH TENSION < 69 KV - ENERGY	E	(277,210)	(1,147,984)	(440)	(24,102)	(8,222)
5							
6	TRANSFORMERS - OH - DEMAND	D	0	(144,494)	(40)	(1,937)	(691)
7	TRANSFORMERS - OH - ENERGY	E	0	(96,296)	(37)	(2,022)	(417)
8	TRANSFORMERS - UG - DEMAND	D	0	(85,371)	(24)	(1,144)	(408)
9	TRANSFORMERS - UG - ENERGY	E	0	(56,894)	(22)	(1,194)	(246)
10							
11	OH LINES DEMAND	D	0	(922,649)	(256)	(12,369)	(4,410)
12	OH LINES ENERGY	E	0	(614,883)	(236)	(12,909)	(2,664)
13	UG LINES DEMAND	D	0	(13,314)	(4)	(178)	(64)
14	UG LINES ENERGY	E	0	(8,873)	(3)	(186)	(38)
15							
16	SERVICES - OH - DEMAND	C	(14,962)	(113,984)	(32)	(1,528)	(330)
17	SERVICES - OH - ENERGY	C	(17,203)	(71,240)	(27)	(1,496)	(510)
18	SERVICES - UG - DEMAND	C	(11,876)	(90,478)	(25)	(1,213)	(262)
19	SERVICES - UG - ENERGY	C	(13,655)	(56,549)	(22)	(1,187)	(405)
20							
21	METER & METER INSTALLATIONS	C	(2,066)	(154,871)	(249)	(5,466)	(2,357)
22	INSTALL. ON CUSTR PREMISES	C	(9,435)	0	0	0	0
23	STREET LIGHTING	C	0	0	0	0	0
24	CUSTOMER ACCOUNTING	C	(1,020)	(1,471,839)	(412)	(40,430)	(31,914)
25	UNCOLLECTIBLES	R	(7,729)	(69,769)	(20)	(1,474)	(705)
26	CUSTOMER SERVICE AND 901 & 905	E	(53,571)	(175,898)	(67)	(3,693)	(1,260)
27	REVENUES	R	786,346	7,253,390	2,072	153,241	73,723
28			-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D	(274,303)	(3,214,692)	(890)	(43,096)	(11,495)
30	TOTAL ENERGY	E	(369,979)	(2,229,534)	(854)	(46,808)	(13,770)
31	TOTAL CUSTOMER	C	(70,216)	(1,958,961)	(767)	(51,320)	(35,778)
32	TOTAL REVENUE	R	778,617	7,183,621	2,052	151,767	73,018
33			-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL		64,120	(219,565)	(460)	10,542	11,975
			===========	===========	===========	===========	===========

			C&I SC2 SEC GEN SERV (11)	C&I SC2 SEC SPACE HTG (12)	C&I SC2 PRIMARY GEN (13)	SC4 MUNI STR LTG (14)	SC6 DUSK TO DAWN (15)	SC6 ENERGY LTG (16)
	FEDERAL INCOME TAX COMPUTATION							
1	HIGH TENSION ≥ 69 KV - DEMAND	D	(105,897)	(5,220)	(14,579)	(1,480)	(795)	(465)
2	HIGH TENSION ≥ 69 KV - ENERGY	E	(88,705)	(4,813)	(14,980)	(1,130)	(598)	(375)
3	HIGH TENSION < 69 KV - DEMAND	D	(930,717)	(45,880)	(128,130)	(13,006)	(6,985)	(4,091)
4	HIGH TENSION < 69 KV - ENERGY	E	(791,195)	(42,929)	(133,614)	(10,077)	(5,330)	(3,349)
5								
6	TRANSFORMERS - OH - DEMAND	D	(73,106)	(3,604)	0	(1,022)	(549)	(321)
7	TRANSFORMERS - OH - ENERGY	E	(66,367)	(3,601)	0	(845)	(447)	(281)
8	TRANSFORMERS - UG - DEMAND	D	(43,193)	(2,129)	0	(604)	(324)	(190)
9	TRANSFORMERS - UG - ENERGY	E	(39,212)	(2,128)	0	(499)	(264)	(166)
10								
11	OH LINES DEMAND	D	(466,810)	(23,011)	0	(6,523)	(3,504)	(2,052)
12	OH LINES ENERGY	E	(423,779)	(22,994)	0	(5,397)	(2,855)	(1,794)
13	UG LINES DEMAND	D	(6,736)	(332)	0	(94)	(51)	(30)
14	UG LINES ENERGY	E	(6,115)	(332)	0	(78)	(41)	(26)
15								
16	SERVICES - OH - DEMAND	C	(57,670)	(2,843)	(7,939)	0	0	(253)
17	SERVICES - OH - ENERGY	C	(49,099)	(2,664)	(8,292)	0	0	0
18	SERVICES - UG - DEMAND	C	(45,777)	(2,257)	(6,302)	0	0	(201)
19	SERVICES - UG - ENERGY	C	(38,973)	(2,115)	(6,582)	0	0	0
20								
21	METER & METER INSTALLATIONS	C	(75,856)	(1,451)	(2,061)	0	0	(551)
22	INSTALL. ON CUSTR PREMISES	C	0	0	0	0	0	0
23	STREET LIGHTING	C	0	0	0	(128,410)	(68,998)	0
24	CUSTOMER ACCOUNTING	C	(170,795)	(3,880)	(1,817)	(494)	(12,893)	(2,406)
25	UNCOLLECTIBLES	R	(39,492)	(1,645)	(5,007)	(1,730)	(741)	(197)
26	CUSTOMER SERVICE AND 901 & 905	E	(121,230)	(6,578)	(20,473)	(1,544)	(817)	(513)
27	REVENUES	R	4,085,880	168,816	522,410	185,598	79,316	20,828
28			-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
29	TOTAL DEMAND	D	(1,626,459)	(80,176)	(142,708)	(22,728)	(12,207)	(7,149)
30	TOTAL ENERGY	E	(1,536,603)	(83,373)	(169,068)	(19,570)	(10,351)	(6,504)
31	TOTAL CUSTOMER	C	(438,170)	(15,209)	(32,992)	(128,904)	(81,891)	(3,412)
32	TOTAL REVENUE	R	4,046,388	167,171	517,403	183,867	78,575	20,631
33			-------------------	-------------------	-------------------	-------------------	-------------------	-------------------
34	TOTAL		445,157	(11,587)	172,635	12,664	(25,874)	3,567
			===========	===========	===========	===========	===========	===========

			SC7 PRIMARY T.O.U. (17)	SC7 SEP MET SP HTG (18)	SC7 HV TOD (19)
	FEDERAL INCOME TAX COMPUTATION				
1	HIGH TENSION ≥ 69 KV - DEMAND	D	(25,627)	(1,847)	(5,366)
2	HIGH TENSION ≥ 69 KV - ENERGY	E	(30,107)	(972)	(8,119)
3	HIGH TENSION < 69 KV - DEMAND	D	(225,231)	(16,232)	0
4	HIGH TENSION < 69 KV - ENERGY	E	(268,535)	(8,674)	0
5					
6	TRANSFORMERS - OH - DEMAND	D	0	0	0
7	TRANSFORMERS - OH - ENERGY	E	0	0	0
8	TRANSFORMERS - UG - DEMAND	D	0	0	0
9	TRANSFORMERS - UG - ENERGY	E	0	0	0
10					
11	OH LINES DEMAND	D	0	0	0
12	OH LINES ENERGY	E	0	0	0
13	UG LINES DEMAND	D	0	0	0
14	UG LINES ENERGY	E	0	0	0
15					
16	SERVICES - OH - DEMAND	C	(13,956)	(1,006)	0
17	SERVICES - OH - ENERGY	C	(16,664)	(538)	0
18	SERVICES - UG - DEMAND	C	(11,078)	(798)	0
19	SERVICES - UG - ENERGY	C	(13,228)	(427)	0
20					
21	METER & METER INSTALLATIONS	C	(1,156)	(546)	(364)
22	INSTALL. ON CUSTR PREMISES	C	(7,149)	(2,285)	0
23	STREET LIGHTING	C	0	0	0
24	CUSTOMER ACCOUNTING	C	(919)	(72)	(29)
25	UNCOLLECTIBLES	R	(7,017)	(375)	(337)
26	CUSTOMER SERVICE AND 901 & 905	E	(41,146)	(1,329)	(11,096)
27	REVENUES	R	720,760	39,322	26,264
28			-------------------	-------------------	-------------------
29	TOTAL DEMAND	D	(250,857)	(18,079)	(5,366)
30	TOTAL ENERGY	E	(339,788)	(10,976)	(19,215)
31	TOTAL CUSTOMER	C	(64,150)	(5,673)	(393)
32	TOTAL REVENUE	R	713,743	38,947	25,927
33			-------------------	-------------------	-------------------
34	TOTAL		58,948	4,219	953
			===========	===========	===========

		TOTAL COMPANY (1)	TOTAL RESIDENTIAL (2)	TOTAL C&I (3)	MUNICIPAL LIGHTING (4)	PRIVATE LIGHTING (5)
	CUSTOMER COST BY CLASS					
1	NUMBER OF CUSTOMERS	73,087	63,651	8,584	26	783
2						
3	RATE BASE	22,681,552	12,156,390	6,930,637	1,347,802	759,708
4						
5	TOTAL CUSTOMER OPERATING EXPS.	11,870,161	8,716,831	2,091,666	481,725	331,111
6	MONTHLY OP. EXPS. COST/CUST	13.53	11.41	20.31	1,543.99	35.24
7						
8	RETURN @ 6.43% (CUSTOMER)	1,309,874	702,039	400,249	77,836	43,874
9	F.I.T. PERCENT ON RETURN	3.94%				
10	INCOME TAX ON RETURN	51,584	27,647	15,762	3,065	1,728
11	TOTAL RETURN & F.I.T.	1,361,458	729,686	416,011	80,902	45,601
12	MONTHLY RET. F.I.T. COST/CUST	1.55	0.96	4.04	259.30	4.85
13						
14	MONTHLY CUSTOMER COSTS	15.09	12.37	24.34	1,803.29	40.09
		===========	===========	===========	===========	===========

		TOTAL PRIMARY (6)	RESID SC1 GENERAL (7)	RESID SC3 T.O.U. (8)	RESID SC5 W/ SP HTG (9)	C&I SC2 SEC NON DEM (10)
	CUSTOMER COST BY CLASS					
1	NUMBER OF CUSTOMERS	43	61,939	17	1,695	1,519
2						
3	RATE BASE	1,487,016	11,860,816	9,184	286,390	118,366
4						
5	TOTAL CUSTOMER OPERATING EXPS.	248,829	8,489,162	3,199	224,470	159,843
6	MONTHLY OP. EXPS. COST/CUST	482.23	11.42	15.68	11.04	8.77
7						
8	RETURN @ 6.43% (CUSTOMER)	85,876	684,970	530	16,539	6,836
9	F.I.T. PERCENT ON RETURN					
10	INCOME TAX ON RETURN	3,382	26,975	21	651	269
11	TOTAL RETURN & F.I.T.	89,258	711,945	551	17,191	7,105
12	MONTHLY RET. F.I.T. COST/CUST	172.98	0.96	2.70	0.85	0.39
13						
14	MONTHLY CUSTOMER COSTS	655.21	12.38	18.38	11.88	9.16
		===========	===========	===========	===========	===========

		C&I SC2 SEC GEN SERV (11)	C&I SC2 SEC SPACE HTG (12)	C&I SC2 PRIMARY GEN (13)	SC4 MUNI STR LTG (14)	SC6 DUSK TO DAWN (15)	SC6 ENERGY LTG (16)
	CUSTOMER COST BY CLASS						
1	NUMBER OF CUSTOMERS	6,816	168	81	26	678	105
2							
3	RATE BASE	5,948,926	235,893	627,452	1,347,802	733,934	25,774
4							
5	TOTAL CUSTOMER OPERATING EXPS.	1,752,612	58,631	120,580	481,725	316,428	14,683
6	MONTHLY OP. EXPS. COST/CUST	21.43	29.08	124.05	1,543.99	38.89	11.65
7							
8	RETURN @ 6.43% (CUSTOMER)	343,554	13,623	36,236	77,836	42,385	1,488
9	F.I.T. PERCENT ON RETURN						
10	INCOME TAX ON RETURN	13,529	536	1,427	3,065	1,669	59
11	TOTAL RETURN & F.I.T.	357,084	14,159	37,663	80,902	44,054	1,547
12	MONTHLY RET. F.I.T. COST/CUST	4.37	7.02	38.75	259.30	5.41	1.23
13							
14	MONTHLY CUSTOMER COSTS	25.79	36.11	162.80	1,803.29	44.31	12.88
		===========	===========	===========	===========	===========	===========

		SC7 PRIMARY T.O.U. (17)	SC7 SEP MET SP HTG (18)	SC7 HV TOD (19)
	CUSTOMER COST BY CLASS			
1	NUMBER OF CUSTOMERS	39	3	1
2				
3	RATE BASE	1,335,087	141,979	9,950
4				
5	TOTAL CUSTOMER OPERATING EXPS.	227,907	19,418	1,505
6	MONTHLY OP. EXPS. COST/CUST	486.98	539.38	125.41
7				
8	RETURN @ 6.43% (CUSTOMER)	77,102	8,199	575
9	F.I.T. PERCENT ON RETURN			
10	INCOME TAX ON RETURN	3,036	323	23
11	TOTAL RETURN & F.I.T.	80,139	8,522	597
12	MONTHLY RET. F.I.T. COST/CUST	171.24	236.73	49.77
13				
14	MONTHLY CUSTOMER COSTS	658.22	776.11	175.18
		===========	===========	===========

		TOTAL COMPANY (1)	TOTAL RESIDENTIAL (2)	TOTAL C&I (3)	MUNICIPAL LIGHTING (4)	PRIVATE LIGHTING (5)
ALLOCATION FACTORS						
KWH SALES		1,592,895,983	742,077,890	617,673,807	6,377,481	5,492,564
PERCENT	E01	100.000000%	46.586714%	38.776782%	0.400370%	0.344816%
KWH SALES EXCLUDING SC 7 HV		1,547,064,449	742,077,890	617,673,807	6,377,481	5,492,564
PERCENT	E01A	100.000000%	47.966837%	39.925538%	0.412231%	0.355031%
KWH SALES EXCLUDING ST. LIGHTING & SC 7 HV		1,535,194,404	742,077,890	617,673,807	0	0
PERCENT	E02	100.000000%	48.337715%	40.234240%	0.000000%	0.000000%
HIGH TENSION - 60 HZ		425,913	241,587	143,813	1,685	1,435
PERCENT	D02	100.000000%	56.722147%	33.765816%	0.395621%	0.336923%
HIGH TENSION - 60 HZ EXCLUDING SC 7 HV		419,803	241,587	143,813	1,685	1,435
PERCENT	D02A	100.000000%	57.547707%	34.257259%	0.401379%	0.341827%
AVERAGE & PEAK FOR LT - DEMAND		31,292,101	20,301,754	10,728,159	141,599	120,590
PERCENT	AP2D	100.000000%	64.878204%	34.283919%	0.452507%	0.385369%
AVERAGE & PEAK FOR LT - ENERGY		23,637,500	13,650,450	9,768,701	117,313	101,035
PERCENT	AP2E	100.000000%	57.749130%	41.327133%	0.496301%	0.427436%
BOOK COST - SERVICES OH & UG		20,648,868	11,956,718	7,117,649	0	26,231
PERCENT	C02	100.000000%	57.904955%	34.469923%	0.000000%	0.127033%
BOOK COST-INSTALL. ON CUST. PREM.		582,740	0	0	0	0
PERCENT	C03	100.000000%	0.000000%	0.000000%	0.000000%	0.000000%
BOOK COST-STREET LIGHTING		4,664,034	0	0	3,033,867	1,630,167
PERCENT	C04	100.000000%	0.000000%	0.000000%	65.048137%	34.951863%
BOOK COST-METERS & METER INSTALL		9,099,423	5,966,041	3,036,182	0	20,461
PERCENT	S01	100.000000%	65.565048%	33.366750%	0.000000%	0.224865%
CUSTOMER ACCOUNTS EXPENSE		4,677,881	4,071,660	560,964	1,331	41,181
PERCENT	S02	100.000000%	87.040695%	11.991835%	0.028450%	0.880333%
UNCOLLECTIBLES ACCOUNTS		611,945	339,347	223,087	8,240	4,466
PERCENT	S03	100.000000%	55.453809%	36.455454%	1.346552%	0.729831%
REVENUES-PAYROLL & MISC.		1,676,956	781,239	650,270	6,714	5,782
PERCENT	S06	100.000000%	46.586714%	38.776782%	0.400370%	0.344816%
REVENUES FROM SALES		65,010,326	36,050,702	23,699,810	875,398	474,466
PERCENT	R01	100.000000%	55.453809%	36.455454%	1.346552%	0.729831%
OTHER ELECTRIC REVENUES		150,527	10,071	49,645	15,114	8,192
PERCENT	R02	100.000000%	6.690752%	32.980714%	10.040561%	5.441984%
NULL REVENUE FACTOR		0	0	0	0	0
PERCENT	R99	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
NUMBER OF CUSTOMERS	K01	73,087	63,651	8,584	26	783

Line			TOTAL PRIMARY (6)	RESID SC1 GENERAL (7)	RESID SC3 T.O.U. (8)	RESID SC5 W/ SP HTG (9)	C&I SC2 SEC NON DEM (10)
	ALLOCATION FACTORS						
1	KWH SALES		221,274,241	726,545,879	278,431	15,253,580	5,203,602
2	PERCENT	E01	13.891318%	45.611634%	0.017480%	0.957601%	0.326676%
3							
4	KWH SALES EXCLUDING SC 7 HV		175,442,707	726,545,879	278,431	15,253,580	5,203,602
5	PERCENT	E01A	11.340362%	46.962871%	0.017997%	0.985969%	0.336353%
6							
7	KWH SALES EXCLUDING ST. LIGHTING & SC 7 HV		175,442,707	726,545,879	278,431	15,253,580	5,203,602
8	PERCENT	E02	11.428045%	47.325985%	0.018137%	0.993593%	0.338954%
9							
10	HIGH TENSION - 60 HZ		37,393	238,326	66	3,195	689
11	PERCENT	D02	8.779493%	55.956498%	0.015496%	0.750153%	0.161770%
12							
13	HIGH TENSION - 60 HZ EXCLUDING SC 7 HV		31,283	238,326	66	3,195	689
14	PERCENT	D02A	7.451829%	56.770914%	0.015722%	0.761071%	0.164125%
15							
16	AVERAGE & PEAK FOR LT - DEMAND		0	20,027,716	5,546	268,492	95,720
17	PERCENT	AP2D	0.000000%	64.002463%	0.017724%	0.858017%	0.305891%
18							
19	AVERAGE & PEAK FOR LT - ENERGY		0	13,364,741	5,122	280,588	57,900
20	PERCENT	AP2E	0.000000%	56.540416%	0.021668%	1.187047%	0.244950%
21							
22	BOOK COST - SERVICES OH & UG		1,548,270	11,795,323	3,266	158,128	34,100
23	PERCENT	C02	7.498089%	57.123340%	0.015819%	0.765796%	0.165143%
24							
25	BOOK COST-INSTALL. ON CUST. PREM.		582,740	0	0	0	0
26	PERCENT	C03	100.000000%	0.000000%	0.000000%	0.000000%	0.000000%
27							
28	BOOK COST-STREET LIGHTING		0	0	0	0	0
29	PERCENT	C04	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
30							
31	BOOK COST-METERS & METER INSTALL		76,739	5,753,698	9,263	203,080	87,583
32	PERCENT	S01	0.843338%	63.231458%	0.101800%	2.231790%	0.962509%
33							
34	CUSTOMER ACCOUNTS EXPENSE		2,745	3,961,725	1,109	108,825	85,904
35	PERCENT	S02	0.058687%	84.690603%	0.023710%	2.326381%	1.836379%
36							
37	UNCOLLECTIBLES ACCOUNTS		36,805	332,233	96	7,018	3,355
38	PERCENT	S03	6.014353%	54.291344%	0.015621%	1.146844%	0.548281%
39							
40	REVENUES-PAYROLL & MISC.		232,951	764,887	293	16,059	5,478
41	PERCENT	S06	13.891318%	45.611634%	0.017480%	0.957601%	0.326676%
42							
43	REVENUES FROM SALES		3,909,950	35,294,980	10,155	745,567	356,439
44	PERCENT	R01	6.014353%	54.291344%	0.015621%	1.146844%	0.548281%
45							
46	OTHER ELECTRIC REVENUES		67,505	9,860	3	208	100
47	PERCENT	R02	44.845989%	6.550496%	0.001885%	0.138372%	0.066153%
48							
49	NULL REVENUE FACTOR		0	0	0	0	0
50	PERCENT	R99	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
51							
52	NUMBER OF CUSTOMERS	K01	43	61,939	17	1,695	1,519

			C&I SC2 SEC GEN SERV (11)	C&I SC2 SEC SPACE HTG (12)	C&I SC2 PRIMARY GEN (13)	SC4 MUNI STR LTG (14)	SC6 DUSK TO DAWN (15)	SC6 ENERGY LTG (16)
	ALLOCATION FACTORS							
1	KWH SALES		500,738,006	27,169,160	84,563,039	6,377,481	3,373,135	2,119,429
2	PERCENT	E01	31.435700%	1.705646%	5.308761%	0.400370%	0.211761%	0.133055%
3								
4	KWH SALES EXCLUDING SC 7 HV		500,738,006	27,169,160	84,563,039	6,377,481	3,373,135	2,119,429
5	PERCENT	E01A	32.366978%	1.756175%	5.466032%	0.412231%	0.218035%	0.136997%
6								
7	KWH SALES EXCLUDING ST. LIGHTING & SC 7 HV		500,738,006	27,169,160	84,563,039	0	0	0
8	PERCENT	E02	32.617238%	1.769754%	5.508295%	0.000000%	0.000000%	0.000000%
9								
10	HIGH TENSION - 60 HZ		120,580	5,944	16,600	1,685	905	530
11	PERCENT	D02	28.310946%	1.395590%	3.897510%	0.395621%	0.212485%	0.124439%
12								
13	HIGH TENSION - 60 HZ EXCLUDING SC 7 HV		120,580	5,944	16,600	1,685	905	530
14	PERCENT	D02A	28.722996%	1.415902%	3.954236%	0.401379%	0.215577%	0.126250%
15								
16	AVERAGE & PEAK FOR LT - DEMAND		10,132,935	499,504	0	141,599	76,052	44,539
17	PERCENT	AP2D	32.381767%	1.596262%	0.000000%	0.452507%	0.243038%	0.142332%
18								
19	AVERAGE & PEAK FOR LT - ENERGY		9,211,027	499,774	0	117,313	62,048	38,987
20	PERCENT	AP2E	38.967856%	2.114327%	0.000000%	0.496301%	0.262500%	0.164936%
21								
22	BOOK COST - SERVICES OH & UG		5,967,792	294,183	821,574	0	0	26,231
23	PERCENT	C02	28.901305%	1.424692%	3.978783%	0.000000%	0.000000%	0.127033%
24								
25	BOOK COST-INSTALL. ON CUST. PREM.		0	0	0	0	0	0
26	PERCENT	C03	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
27								
28	BOOK COST-STREET LIGHTING		0	0	0	3,033,867	1,630,167	0
29	PERCENT	C04	0.000000%	0.000000%	0.000000%	65.048137%	34.951863%	0.000000%
30								
31	BOOK COST-METERS & METER INSTALL		2,818,153	53,892	76,554	0	0	20,461
32	PERCENT	S01	30.970672%	0.592263%	0.841306%	0.000000%	0.000000%	0.224865%
33								
34	CUSTOMER ACCOUNTS EXPENSE		459,726	10,445	4,890	1,331	34,704	6,476
35	PERCENT	S02	9.827653%	0.223278%	0.104525%	0.028450%	0.741885%	0.138449%
36								
37	UNCOLLECTIBLES ACCOUNTS		188,055	7,834	23,843	8,240	3,528	938
38	PERCENT	S03	30.730738%	1.280194%	3.896241%	1.346552%	0.576485%	0.153346%
39								
40	REVENUES-PAYROLL & MISC.		527,163	28,603	89,026	6,714	3,551	2,231
41	PERCENT	S06	31.435700%	1.705646%	5.308761%	0.400370%	0.211761%	0.133055%
42								
43	REVENUES FROM SALES		19,978,153	832,258	2,532,959	875,398	374,775	99,691
44	PERCENT	R01	30.730738%	1.280194%	3.896241%	1.346552%	0.576485%	0.153346%
45								
46	OTHER ELECTRIC REVENUES		5,581	233	43,732	15,114	6,470	1,721
47	PERCENT	R02	3.707802%	0.154461%	29.052298%	10.040561%	4.298559%	1.143424%
48								
49	NULL REVENUE FACTOR		0	0	0	0	0	0
50	PERCENT	R99	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
51								
52	NUMBER OF CUSTOMERS	K01	6,816	168	81	26	678	105

		SC7 PRIMARY T.O.U. (17)	SC7 SEP MET SP HTG (18)	SC7 HV TOD (19)
ALLOCATION FACTORS				
KWH SALES		169,952,948	5,489,759	45,831,534
PERCENT	E01	10.669432%	0.344640%	2.877246%
KWH SALES EXCLUDING SC 7 HV		169,952,948	5,489,759	0
PERCENT	E01A	10.985512%	0.354850%	0.000000%
KWH SALES EXCLUDING ST. LIGHTING & SC 7 HV		169,952,948	5,489,759	0
PERCENT	E02	11.070451%	0.357594%	0.000000%
HIGH TENSION - 60 HZ		29,180	2,103	6,110
PERCENT	D02	6.851164%	0.493763%	1.434565%
HIGH TENSION - 60 HZ EXCLUDING SC 7 HV		29,180	2,103	0
PERCENT	D02A	6.950879%	0.500949%	0.000000%
AVERAGE & PEAK FOR LT - DEMAND		0	0	0
PERCENT	AP2D	0.000000%	0.000000%	0.000000%
AVERAGE & PEAK FOR LT - ENERGY		0	0	0
PERCENT	AP2E	0.000000%	0.000000%	0.000000%
BOOK COST - SERVICES OH & UG		1,444,188	104,082	0
PERCENT	C02	6.994029%	0.504059%	0.000000%
BOOK COST-INSTALL. ON CUST. PREM.		441,586	141,154	0
PERCENT	C03	75.777521%	24.222479%	0.000000%
BOOK COST-STREET LIGHTING		0	0	0
PERCENT	C04	0.000000%	0.000000%	0.000000%
BOOK COST-METERS & METER INSTALL		42,930	20,285	13,524
PERCENT	S01	0.471789%	0.222929%	0.148620%
CUSTOMER ACCOUNTS EXPENSE		2,474	193	78
PERCENT	S02	0.052891%	0.004134%	0.001662%
UNCOLLECTIBLES ACCOUNTS		33,415	1,786	1,604
PERCENT	S03	5.460404%	0.291877%	0.262072%
REVENUES-PAYROLL & MISC.		178,922	5,779	48,250
PERCENT	S06	10.669432%	0.344640%	2.877246%
REVENUES FROM SALES		3,549,826	189,750	170,374
PERCENT	R01	5.460404%	0.291877%	0.262072%
OTHER ELECTRIC REVENUES		61,288	3,276	2,942
PERCENT	R02	40.715473%	2.176381%	1.954135%
NULL REVENUE FACTOR		0	0	0
PERCENT	R99	0.000000%	0.000000%	0.000000%
NUMBER OF CUSTOMERS	K01	39	3	1

Rockland Electric Company
2016 Embedded Cost-Of-Service Study Results at April 19 Rates
NJBPU Sponsored Methodology

Service Classification	Rate of Return %	Initial Surplus/Deficiency*	Adjustment*	Adjusted Surplus/Deficiency*
TOTAL RESIDENTIAL	4.27%	(1,354,246)	(199,527)	(1,553,773)
TOTAL C&I	7.93%	1,515,367	(4,703)	1,510,664
MUNICIPAL LIGHTING	10.19%	102,991	-	102,991
PRIVATE LIGHTING	1.56%	(69,352)	(2,118)	(71,470)
TOTAL PRIMARY	6.40%	12,551	(963)	11,588
RESID SC1 GENERAL	4.23%	(1,369,641)	(199,469)	(1,569,110)
RESID SC3 W/SP & OR W/WT HTG. T.O.U.	0.51%	(2,426)	(58)	(2,484)
RESID SC5 W/SP HTG	7.09%	17,820	-	17,820
C&I SC2 SECONDARY NON DEM MET	13.39%	50,970	-	50,970
C&I SC2 GENERAL SERVICE SEC	7.42%	854,416	-	854,416
C&I SC2 GENERAL SVC. SPACE HTG	3.40%	(72,641)	(4,703)	(77,344)
C&I SC2 GENERAL SVC. PRIMARY	14.75%	682,622	-	682,622
SC4 MUNI STREET LTG	10.19%	102,991	-	102,991
SC6 DUSK TO DAWN OH LIGHTING	-0.39%	(81,026)	(2,118)	(83,144)
SC6 ENERGY LTG	9.72%	11,674	-	11,674
SC7 C&I PRIMARY T.O.U.	6.44%	13,894	-	13,894
SC7 C&I SEP. METERED SP. HTG.	7.04%	6,063	-	6,063
SC7 HV TOD	3.16%	(7,406)	(963)	(8,369)
Total System		207,311	(207,311)	(0)
			(207,311)	

* Deficiencies shown as negative

LIST OF SCHEDULES AND APPENDICES

SCHEDULE 1
SUMMARY OF DISCOUNTED CASH FLOW ANALYSIS
FOR ELECTRIC UTILITIES

	COMPANY	MOST RECENT QUARTERLY DIVIDEND (d0)	STOCK PRICE P_0	FORECAST OF FUTURE EARNINGS GROWTH	DCF MODEL RESULT
1	Alliant Energy	0.335	43.472	6.9%	10.5%
2	Amer. Elec. Power	0.670	75.998	5.8%	9.7%
3	Ameren Corp.	0.475	66.702	7.7%	11.0%
4	AVANGRID, Inc.	0.440	49.536	9.2%	13.4%
5	Black Hills	0.505	63.680	4.4%	7.8%
6	CenterPoint Energy	0.278	28.450	10.1%	14.8%
7	CMS Energy Corp.	0.383	50.325	7.3%	10.6%
8	Consol. Edison	0.715	77.296	3.0%	7.2%
9	Dominion Energy	0.835	71.933	6.3%	11.8%
10	DTE Energy	0.945	114.174	5.4%	9.0%
11	Duke Energy	0.928	85.863	4.4%	9.2%
12	Edison Int'l	0.613	57.007	3.8%	8.6%
13	El Paso Electric	0.360	53.340	5.1%	8.1%
14	Evergy, Inc.	0.475	57.626	9.2%	12.8%
15	Eversource Energy	0.505	66.003	5.8%	9.3%
16	Exelon Corp.	0.345	45.235	5.2%	8.7%
17	Hawaiian Elec.	0.310	36.958	7.8%	11.8%
18	NextEra Energy	1.110	174.820	9.7%	12.7%
19	Otter Tail Corp.	0.335	47.795	9.0%	12.4%
20	Pinnacle West Capital	0.738	86.233	3.7%	7.4%
21	PNM Resources	0.290	41.456	4.1%	7.0%
22	Portland General	0.363	46.710	5.1%	8.6%
23	PPL Corp.	0.410	30.100	3.6%	9.7%
24	Public Serv. Enterprise	0.450	53.078	7.3%	11.2%
25	Sempra Energy	0.895	112.447	8.6%	12.4%
26	Southern Co.	0.600	45.740	1.8%	7.5%
27	WEC Energy Group	0.553	70.340	5.7%	9.3%
28	Xcel Energy Inc.	0.380	50.413	6.6%	10.2%
29	Average				10.1%

Notes:

d_0	=	Most recent quarterly dividend.
d_1,d_2,d_3,d_4	=	Next four quarterly dividends, calculated by multiplying the last four quarterly dividends by the factor (1 + g).
P_0	=	Average of the monthly high and low stock prices during the three months ending January 2019 per Refinitiv (formerly Thomson Reuters).
FC	=	Flotation cost allowance (five percent) as a percent of stock price.
g	=	I/B/E/S forecast of future earnings growth January 2019 from Refinitiv (formerly Thomson Reuters).
k	=	Cost of equity using the quarterly version of the DCF model.

$$k = \frac{d_1(1+k)^{.75} + d_2(1+k)^{.50} + d_3(1+k)^{.25} + d_4}{P_0(1-FC)} + g$$

My analysis does not include results for companies that do not have an investment-grade bond rating (PCG), do not have an I/B/E/S long-term growth forecast (ALE, AVA, FTS.TO, MGEE), do not have a positive I/B/E/S long-term growth forecast (OGE, ETR, FE), or results that are less than one hundred basis points above the forecasted bond yield for a company's rating (IDA, NWE).

SCHEDULE 2
USING THE ARITHMETIC MEAN TO ESTIMATE
THE COST OF EQUITY CAPITAL

Consider an investment that in a given year generates a return of 30 percent with probability equal to .5 and a return of -10 percent with a probability equal to .5. For each one dollar invested, the possible outcomes of this investment at the end of year one are:

WEALTH AFTER ONE YEAR	PROBABILITY
\$1.30	0.50
\$0.90	0.50

At the end of year two, the possible outcomes are:

WEALTH AFTER TWO YEARS			PROBABILITY	WEALTH x PROBABILITY
(1.30) (1.30)	=	\$1.69	0.25	0.4225
(1.30) (.9)	=	\$1.17	0.25	0.2925
(.9) (1.30)	=	\$1.17	0.25	0.2925
(.9) (.9)	=	\$0.81	0.25	0.2025
Expected Wealth	=			\$1.21

The expected value of this investment at the end of year two is \$1.21. In a competitive capital market, the cost of equity is equal to the expected rate of return on an investment. In the above example, the cost of equity is that rate of return which will make the initial investment of one dollar grow to the expected value of \$1.21 at the end of two years. Thus, the cost of equity is the solution to the equation:

$$1(1+k)^2 = 1.21 \text{ or}$$

$$k = (1.21/1)^{.5} - 1 = 10\%.$$

The arithmetic mean of this investment is:

$$(30\%)\ (.5) + (-10\%)\ (.5) = 10\%.$$

Thus, the arithmetic mean is equal to the cost of equity capital.

The geometric mean of this investment is:

$$[(1.3)\ (.9)]^{.5} - 1 = .082 = 8.2\%.$$

Thus, the geometric mean is not equal to the cost of equity capital.

The lesson is obvious: for an investment with an uncertain outcome, the arithmetic mean is the best measure of the cost of equity capital.

SCHEDULE 3
COMPARISON OF RISK PREMIA ON
S&P 500 AND S&P UTILITIES 1937 – 2019

YEAR	S&P UTILITIES STOCK RETURN	SP500 STOCK RETURN	10-YR. TREASURY BOND YIELD	UTILITIES RISK PREMIUM	MARKET RISK PREMIUM
2018	0.0367	-0.0456	0.0291	0.0076	-0.0747
2017	0.1172	0.2471	0.0233	0.0939	0.2238
2016	0.1744	0.2080	0.0184	0.1560	0.1896
2015	-0.0390	-0.0332	0.0214	-0.0604	-0.0546
2014	0.2891	0.1339	0.0254	0.2637	0.1085
2013	0.1301	0.2524	0.0235	0.1066	0.2289
2012	0.0209	0.1602	0.0180	0.0029	0.1422
2011	0.1999	0.0325	0.0278	0.1721	0.0047
2010	0.0704	0.1618	0.0322	0.0382	0.1296
2009	0.1071	0.3291	0.0326	0.0745	0.2965
2008	-0.2590	-0.3516	0.0367	-0.2957	-0.3883
2007	0.1656	-0.0138	0.0463	0.1193	-0.0601
2006	0.2076	0.1320	0.0479	0.1597	0.0841
2005	0.1605	0.1001	0.0429	0.1176	0.0572
2004	0.2284	0.0594	0.0427	0.1857	0.0167
2003	0.2348	0.2822	0.0401	0.1947	0.2421
2002	-0.1473	-0.2005	0.0461	-0.1934	-0.2466
2001	-0.1790	-0.1347	0.0502	-0.2292	-0.1849
2000	0.3278	-0.0513	0.0603	0.2675	-0.1116
1999	-0.0172	0.1546	0.0564	-0.0736	0.0982
1998	0.1547	0.3125	0.0526	0.1021	0.2599
1997	0.1858	0.2768	0.0635	0.1223	0.2133
1996	0.0383	0.2702	0.0644	-0.0261	0.2058
1995	0.3749	0.3493	0.0658	0.3091	0.2835
1994	-0.0383	0.0105	0.0708	-0.1091	-0.0603
1993	0.1095	0.1156	0.0587	0.0508	0.0569
1992	0.1246	0.0750	0.0701	0.0545	0.0049
1991	0.1425	0.3165	0.0786	0.0639	0.2379
1990	0.0033	-0.0085	0.0855	-0.0822	-0.0940
1989	0.3468	0.2276	0.0850	0.2618	0.1426
1988	0.1480	0.1761	0.0884	0.0596	0.0877
1987	-0.0574	-0.0213	0.0838	-0.1412	-0.1051
1986	0.3787	0.3095	0.0768	0.3019	0.2327
1985	0.3000	0.2583	0.1062	0.1938	0.1521
1984	0.1995	0.0741	0.1244	0.0751	-0.0503
1983	0.2016	0.2012	0.1110	0.0906	0.0902
1982	0.3020	0.2896	0.1300	0.1720	0.1596
1981	0.0940	-0.0700	0.1391	-0.0451	-0.2091
1980	0.1301	0.2534	0.1146	0.0155	0.1388

YEAR	S&P UTILITIES STOCK RETURN	SP500 STOCK RETURN	10-YR. TREASURY BOND YIELD	UTILITIES RISK PREMIUM	MARKET RISK PREMIUM
1979	0.0879	0.1652	0.0944	-0.0065	0.0708
1978	0.0396	0.1580	0.0841	-0.0445	0.0739
1977	0.0416	-0.0906	0.0742	-0.0326	-0.1648
1976	0.2270	0.1096	0.0761	0.1509	0.0335
1975	0.3224	0.3856	0.0799	0.2425	0.3057
1974	-0.1429	-0.2086	0.0756	-0.2185	-0.2842
1973	-0.1345	-0.1614	0.0684	-0.2029	-0.2298
1972	0.0512	0.1758	0.0621	-0.0109	0.1137
1971	-0.0007	0.1381	0.0616	-0.0623	0.0765
1970	0.1945	0.0708	0.0735	0.1210	-0.0027
1969	-0.1438	-0.0840	0.0667	-0.2105	-0.1507
1968	0.0528	0.1045	0.0565	-0.0037	0.0480
1967	0.0022	0.1605	0.0507	-0.0485	0.1098
1966	-0.0172	-0.0648	0.0492	-0.0664	-0.1140
1965	0.0134	0.1135	0.0428	-0.0294	0.0707
1964	0.1611	0.1570	0.0419	0.1192	0.1151
1963	0.0947	0.2082	0.0400	0.0547	0.1682
1962	0.0425	-0.0284	0.0395	0.0030	-0.0679
1961	0.2247	0.1894	0.0388	0.1859	0.1506
1960	0.2252	0.0618	0.0412	0.1840	0.0206
1959	0.0500	0.0757	0.0433	0.0067	0.0324
1958	0.3688	0.3974	0.0332	0.3356	0.3642
1957	0.0790	-0.0518	0.0365	0.0425	-0.0883
1956	0.0716	0.0714	0.0318	0.0398	0.0396
1955	0.1016	0.2840	0.0282	0.0734	0.2558
1954	0.2237	0.4552	0.0240	0.1997	0.4312
1953	0.0962	0.0270	0.0281	0.0681	-0.0011
1952	0.1536	0.1405	0.0248	0.1288	0.1157
1951	0.1710	0.2039	0.0241	0.1469	0.1798
1950	0.0460	0.3230	0.0205	0.0255	0.3025
1949	0.2783	0.1610	0.0193	0.2590	0.1417
1948	0.0541	0.0928	0.0215	0.0326	0.0713
1947	-0.1041	0.0199	0.0185	-0.1226	0.0014
1946	-0.0700	-0.1203	0.0174	-0.0874	-0.1377
1945	0.5789	0.3818	0.0173	0.5616	0.3645
1944	0.2065	0.1879	0.0209	0.1856	0.1670
1943	0.3745	0.2298	0.0207	0.3538	0.2091
1942	0.1736	0.2087	0.0211	0.1525	0.1876
1941	-0.2838	-0.0898	0.0199	-0.3037	-0.1097
1940	-0.1652	-0.0965	0.0220	-0.1872	-0.1185
1939	0.1126	0.0189	0.0235	0.0891	-0.0046
1938	0.1954	0.1836	0.0255	0.1699	0.1581
1937	-0.3693	-0.3136	0.0269	-0.3962	-0.3405
Risk Premium 1937 to 2019				0.0546	0.0611
RP Utilities/RP SP500				0.89	

SCHEDULE 4
CALCULATION OF CAPITAL ASSET PRICING MODEL COST OF EQUITY
USING AN HISTORICAL 7.1 PERCENT RISK PREMIUM

LINE	COMPANY	VALUE LINE BETA	RISK-FREE RATE	MARKET RISK PREMIUM	BETA X RISK PREMIUM	CAPM COST OF EQUITY
1	ALLETE	0.65	3.8%	7.1%	4.6%	8.6%
2	Alliant Energy	0.60	3.8%	7.1%	4.2%	8.2%
3	Amer. Elec. Power	0.55	3.8%	7.1%	3.9%	7.9%
4	Ameren Corp.	0.55	3.8%	7.1%	3.9%	7.9%
5	AVANGRID Inc.	0.30	3.8%	7.1%	2.1%	6.1%
6	Avista	0.65	3.8%	7.1%	4.6%	8.6%
7	Black Hills	0.75	3.8%	7.1%	5.3%	9.3%
8	CenterPoint Energy	0.85	3.8%	7.1%	6.0%	10.0%
9	CMS Energy Corp.	0.55	3.8%	7.1%	3.9%	7.9%
10	Consol. Edison	0.40	3.8%	7.1%	2.8%	6.8%
11	Dominion Energy	0.60	3.8%	7.1%	4.2%	8.2%
12	DTE Energy	0.55	3.8%	7.1%	3.9%	7.9%
13	Duke Energy	0.50	3.8%	7.1%	3.5%	7.5%
14	Edison Int'l	0.55	3.8%	7.1%	3.9%	7.9%
15	El Paso Electric	0.65	3.8%	7.1%	4.6%	8.6%
16	Entergy Corp.	0.60	3.8%	7.1%	4.2%	8.2%
17	Eversource Energy	0.60	3.8%	7.1%	4.2%	8.2%
18	Exelon Corp.	0.65	3.8%	7.1%	4.6%	8.6%
19	FirstEnergy Corp.	0.60	3.8%	7.1%	4.2%	8.2%
20	Fortis Inc.	0.60	3.8%	7.1%	4.2%	8.2%
21	Hawaiian Elec.	0.60	3.8%	7.1%	4.2%	8.2%
22	IDACORP Inc.	0.55	3.8%	7.1%	3.9%	7.9%
23	MGE Energy	0.60	3.8%	7.1%	4.2%	8.2%
24	NextEra Energy	0.55	3.8%	7.1%	3.9%	7.9%
25	NorthWestern Corp.	0.55	3.8%	7.1%	3.9%	7.9%
26	OGE Energy	0.85	3.8%	7.1%	6.0%	10.0%
27	Otter Tail Corp.	0.75	3.8%	7.1%	5.3%	9.3%
28	Pinnacle West Capital	0.55	3.8%	7.1%	3.9%	7.9%
29	PNM Resources	0.65	3.8%	7.1%	4.6%	8.6%
30	Portland General	0.60	3.8%	7.1%	4.2%	8.2%
31	PPL Corp.	0.70	3.8%	7.1%	4.9%	8.9%
32	Public Serv. Enterprise	0.60	3.8%	7.1%	4.2%	8.2%
33	Sempra Energy	0.75	3.8%	7.1%	5.3%	9.3%
34	Southern Co.	0.50	3.8%	7.1%	3.5%	7.5%
35	WEC Energy Group	0.50	3.8%	7.1%	3.5%	7.5%
36	Xcel Energy Inc.	0.50	3.8%	7.1%	3.5%	7.5%
37	Historical CAPM Result 0.60 Beta	0.60	3.8%	7.1%	4.2%	8.2%
38	Historical CAPM Result 0.89 Beta	0.89	3.8%	7.1%	6.3%	10.3%
39	Average historical CAPM Result					9.3%
	Market Risk Premium	7.1%				
	Risk-free Rate	3.8%				
	Flotation	0.20%				

Notes:

I apply my CAPM analysis to all investment-grade Value Line electric utilities with sufficient data. (EVRG has no Value Line beta, and PCG is bankrupt.)

Historical Ibbotson® SBBI® risk premium including years 1926 through year end 2017 from 2018 SBBI Yearbook. Value Line beta for comparable companies from Value Line Investment Analyzer. Historical utility beta equal to 0.89 calculated per JHV Shcedule 4. Treasury bond yield forecast from data in Value Line Selection & Opinion, November 30, 2018, and Energy Information Administration, 2019, determined as follows. Value Line forecasts a yield on 10-year Treasury notes equal to 3.5 percent. The spread between the average yield on 10-year Treasury notes (2.71 percent) and 20-year Treasury bonds (2.89 percent) is 18 basis points. Adding 18 basis points to Value Line's 3.5 percent forecasted yield on 10-year Treasury notes produces a forecasted yield of 3.68 percent for 20-year Treasury bonds. EIA forecasts a yield of 3.73 percent on 10-year Treasury notes. Adding the 18 basis point spread between 10-year Treasury notes and 20-year Treasury bonds to the EIA forecast of 3.73 percent for 10-year Treasury notes produces an EIA forecast for 20-year Treasury bonds equal to 3.9 percent. The average of the forecasts is 3.8 percent (3.7 percent using Value Line data and 3.9 percent using EIA data).

.

SCHEDULE 5
CALCULATION OF CAPITAL ASSET PRICING MODEL (CAPM) COST OF EQUITY USING DCF ESTIMATE OF THE EXPECTED RATE OF RETURN ON THE MARKET PORTFOLIO

LINE	COMPANY	VALUE LINE BETA	RISK-FREE RATE	DCF S&P 500	MARKET RISK PREMIUM	BETA X RISK PREMIUM	CAPM COST OF EQUITY
1	ALLETE	0.65	3.8%	14.2%	10.4%	6.76%	10.8%
2	Alliant Energy	0.60	3.8%	14.2%	10.4%	6.24%	10.2%
3	Amer. Elec. Power	0.55	3.8%	14.2%	10.4%	5.72%	9.7%
4	Ameren Corp.	0.55	3.8%	14.2%	10.4%	5.72%	9.7%
5	AVANGRID Inc.	0.30	3.8%	14.2%	10.4%	3.12%	7.1%
6	Avista	0.65	3.8%	14.2%	10.4%	6.76%	10.8%
7	Black Hills	0.75	3.8%	14.2%	10.4%	7.80%	11.8%
8	CenterPoint Energy	0.85	3.8%	14.2%	10.4%	8.84%	12.8%
9	CMS Energy Corp.	0.55	3.8%	14.2%	10.4%	5.72%	9.7%
10	Consol. Edison	0.40	3.8%	14.2%	10.4%	4.16%	8.2%
11	Dominion Energy	0.60	3.8%	14.2%	10.4%	6.24%	10.2%
12	DTE Energy	0.55	3.8%	14.2%	10.4%	5.72%	9.7%
13	Duke Energy	0.50	3.8%	14.2%	10.4%	5.20%	9.2%
14	Edison Int'l	0.55	3.8%	14.2%	10.4%	5.72%	9.7%
15	El Paso Electric	0.65	3.8%	14.2%	10.4%	6.76%	10.8%
16	Entergy Corp.	0.60	3.8%	14.2%	10.4%	6.24%	10.2%
17	Eversource Energy	0.60	3.8%	14.2%	10.4%	6.24%	10.2%
18	Exelon Corp.	0.65	3.8%	14.2%	10.4%	6.76%	10.8%
19	FirstEnergy Corp.	0.60	3.8%	14.2%	10.4%	6.24%	10.2%
20	Fortis Inc.	0.60	3.8%	14.2%	10.4%	6.24%	10.2%
21	Hawaiian Elec.	0.60	3.8%	14.2%	10.4%	6.24%	10.2%
22	IDACORP Inc.	0.55	3.8%	14.2%	10.4%	5.72%	9.7%
23	MGE Energy	0.60	3.8%	14.2%	10.4%	6.24%	10.2%
24	NextEra Energy	0.55	3.8%	14.2%	10.4%	5.72%	9.7%
25	NorthWestern Corp.	0.55	3.8%	14.2%	10.4%	5.72%	9.7%
26	OGE Energy	0.85	3.8%	14.2%	10.4%	8.84%	12.8%
27	Otter Tail Corp.	0.75	3.8%	14.2%	10.4%	7.80%	11.8%
28	Pinnacle West Capital	0.55	3.8%	14.2%	10.4%	5.72%	9.7%
29	PNM Resources	0.65	3.8%	14.2%	10.4%	6.76%	10.8%
30	Portland General	0.60	3.8%	14.2%	10.4%	6.24%	10.2%
31	PPL Corp.	0.70	3.8%	14.2%	10.4%	7.28%	11.3%
32	Public Serv. Enterprise	0.60	3.8%	14.2%	10.4%	6.24%	10.2%
33	Sempra Energy	0.75	3.8%	14.2%	10.4%	7.80%	11.8%
34	Southern Co.	0.50	3.8%	14.2%	10.4%	5.20%	9.2%
35	WEC Energy Group	0.50	3.8%	14.2%	10.4%	5.20%	9.2%
36	Xcel Energy Inc.	0.50	3.8%	14.2%	10.4%	5.20%	9.2%
37	Average DCF CAPM Result 0.60 Beta	0.60	3.8%	14.2%	10.4%	6.23%	10.2%
38	Historical Utility Beta 0.89	0.89	3.8%	14.2%	10.4%	9.26%	13.3%
39	Average DCF CAPM Result						11.7%
	Risk-free Rate	3.8%					
	Flotation	0.20%					
	DCF S&P 500 January 2019	14.2%					

Notes:

I apply my CAPM analysis to all investment-grade Value Line electric utilities with sufficient data. (EVRG has no Value Line beta, and PCG is bankrupt.)

Historical Ibbotson® SBBI® risk premium including years 1926 through year end 2017 from 2018 SBBI Yearbook. Historical utility beta per Schedule 5. Treasury bond yield forecast from data in Value Line Selection & Opinion, November 30, 2018, and Energy Information Administration, 2019, determined as follows. Value Line forecasts a yield on 10-year Treasury notes equal to 3.5 percent. The spread between the average yield on 10-year Treasury notes (2.71 percent) and 20-year Treasury bonds (2.89 percent) is 18 basis points. Adding 18 basis points to Value Line's 3.5 percent forecasted yield on 10-year Treasury notes produces a forecasted yield of 3.68 percent for 20-year Treasury bonds. EIA forecasts a yield of 3.73 percent on 10-year Treasury notes. Adding the 18 basis point spread between 10-year Treasury notes and 20-year Treasury bonds to the EIA forecast of 3.73 percent for 10-year Treasury notes produces an EIA forecast for 20-year Treasury bonds equal to 3.9 percent. The average of the forecasts is 3.8 percent (3.7 percent using Value Line data and 3.9 percent using EIA data).

SCHEDULE 5 (CONTINUED)
SUMMARY OF DISCOUNTED CASH FLOW ANALYSIS
FOR S&P 500 COMPANIES

	COMPANY	STOCK PRICE (P_0)	D_0	FORECAST OF FUTURE EARNINGS GROWTH	MODEL RESULT	MARKET CAP $ (MILS)
1	3M	195.41	5.76	9.01%	12.3%	110,535
2	ABBOTT LABORATORIES	70.17	1.28	11.68%	13.7%	123,857
3	AGILENT TECHS.	68.45	0.66	10.51%	11.6%	22,559
4	ALBEMARLE	88.07	1.34	12.49%	14.2%	7,996
5	ALLEGION	85.46	1.08	11.17%	12.6%	7,772
6	ALLIANCE DATA SYSTEMS	179.93	2.52	12.43%	14.0%	9,244
7	ALTRIA GROUP	52.40	3.20	8.40%	15.2%	88,193
8	AMERISOURCEBERGEN	81.82	1.60	9.48%	11.6%	16,150
9	AON CLASS A	153.63	1.60	15.22%	16.4%	36,729
10	APPLE	172.53	2.92	13.00%	14.9%	739,618
11	AT&T	29.88	2.04	5.93%	13.3%	222,998
12	AVERY DENNISON	93.28	2.08	13.37%	15.9%	8,222
13	BALL	47.41	0.40	10.81%	11.7%	16,790
14	BANK OF NEW YORK MELLON	49.09	1.12	9.43%	11.9%	50,952
15	BAXTER INTL.	66.34	0.76	13.70%	15.0%	36,782
16	BECTON DICKINSON	233.93	3.08	12.56%	14.0%	63,529
17	BLACKROCK	403.48	13.20	8.34%	11.9%	65,393
18	BRISTOL MYERS SQUIBB	50.66	1.64	11.06%	14.7%	80,957
19	CARNIVAL	55.16	2.00	11.75%	15.9%	28,201
20	CHUBB	128.87	2.92	10.80%	13.3%	61,223
21	CHURCH & DWIGHT CO.	65.33	0.91	10.73%	12.3%	16,594
22	CISCO SYSTEMS	45.04	1.32	8.93%	12.2%	198,766
23	CITRIX SYS.	105.67	1.40	10.87%	12.3%	14,429
24	COGNIZANT TECH.SLTN.'A'	66.98	0.80	10.96%	12.3%	38,534
25	CONSTELLATION BRANDS 'A'	179.14	2.96	9.25%	11.1%	26,708
26	COSTCO WHOLESALE	216.18	2.28	11.12%	12.3%	93,146
27	COTY CL.A	8.04	0.50	8.00%	14.9%	5,580
28	CSX	67.06	0.96	11.68%	13.3%	54,963
29	CUMMINS	141.79	4.56	12.21%	15.9%	23,297
30	CVS HEALTH	71.67	2.00	12.35%	15.5%	81,950
31	DARDEN RESTAURANTS	105.61	3.00	13.23%	16.5%	13,340
32	DOLLAR GENERAL	109.43	1.16	14.03%	15.2%	29,514
33	EATON	72.44	2.64	10.37%	14.4%	30,758
34	EBAY	29.41	0.56	10.78%	12.9%	29,251
35	ECOLAB	151.90	1.84	13.37%	14.7%	44,059
36	ELI LILLY	113.40	2.58	13.63%	16.2%	126,229
37	EMERSON ELECTRIC	64.38	1.96	8.96%	12.3%	38,822
38	FEDEX	195.30	2.60	9.71%	11.2%	45,231
39	FIDELITY NAT.INFO.SVS.	103.27	1.40	13.25%	14.8%	34,128
40	FOOT LOCKER	52.84	1.38	10.54%	13.5%	6,501
41	FORTIVE	71.61	0.28	14.21%	14.7%	23,838
42	GAP	26.12	0.97	9.99%	14.1%	9,761
43	HCA HEALTHCARE	133.67	1.60	15.25%	16.6%	46,138
44	HOME DEPOT	175.03	4.12	14.09%	16.8%	197,521
45	ILLINOIS TOOL WORKS	130.91	4.00	11.70%	15.2%	44,020
46	INTEL	47.38	1.26	10.23%	13.2%	221,217
47	INTERCONTINENTAL EX.	76.34	1.10	13.67%	15.3%	42,633

	COMPANY	STOCK PRICE (P_0)	D_0	FORECAST OF FUTURE EARNINGS GROWTH	MODEL RESULT	MARKET CAP $ (MILS)
48	INTERNATIONAL PAPER	44.04	2.00	11.50%	16.7%	18,226
49	INTUIT	203.70	1.88	14.57%	15.6%	54,946
50	J M SMUCKER	101.79	3.40	8.40%	12.1%	11,851
51	JACOBS ENGR.	64.91	0.68	12.12%	13.3%	8,614
52	KOHL'S	67.85	2.44	10.75%	14.8%	11,368
53	KRAFT HEINZ	48.43	2.50	5.62%	11.2%	57,411
54	MARSH & MCLENNAN	83.81	1.66	11.44%	13.7%	41,495
55	MCCORMICK & COMPANY NV.	140.75	2.28	10.55%	12.4%	17,223
56	MERCK & COMPANY	74.87	2.20	9.42%	12.7%	196,589
57	MICROSOFT	104.01	1.84	13.68%	15.7%	814,600
58	MOTOROLA SOLUTIONS	121.19	2.28	14.62%	16.8%	18,598
59	NASDAQ	85.38	1.76	11.92%	14.2%	13,517
60	NEWELL BRANDS (XSC)	20.33	0.92	8.07%	13.0%	9,677
61	NEXTERA ENERGY	174.82	4.44	9.68%	12.5%	83,875
62	NIKE 'B'	74.47	0.88	14.18%	15.5%	99,607
63	NVIDIA	157.17	0.64	15.12%	15.6%	92,549
64	ORACLE	47.63	0.76	10.03%	11.8%	174,350
65	PACKAGING CORP.OF AM.	91.29	3.16	10.61%	14.5%	8,526
66	PERKINELMER	82.16	0.28	14.97%	15.4%	9,381
67	PFIZER	43.11	1.44	7.45%	11.1%	246,326
68	PHILIP MORRIS INTL.	78.29	4.56	5.91%	12.2%	112,734
69	PNC FINL.SVS.GP.	125.45	3.80	8.33%	11.6%	56,243
70	PVH	106.58	0.15	13.50%	13.7%	8,146
71	QUALCOMM	56.53	2.48	10.73%	15.7%	66,283
72	RALPH LAUREN CL.A	112.53	2.50	11.29%	13.8%	5,886
73	ROCKWELL AUTOMATION	165.32	3.88	9.97%	12.6%	19,158
74	ROSS STORES	87.37	0.90	12.01%	13.2%	33,649
75	SEAGATE TECH.	41.62	2.52	6.06%	12.6%	11,085
76	SKYWORKS SOLUTIONS	71.81	1.52	11.18%	13.6%	12,015
77	SOUTHWEST AIRLINES	51.06	0.64	15.26%	16.7%	28,447
78	STANLEY BLACK & DECKER	124.96	2.64	9.89%	12.2%	20,038
79	STRYKER	165.23	2.08	10.47%	11.9%	61,520
80	SYMANTEC	20.27	0.30	12.23%	13.9%	12,784
81	SYSCO	64.52	1.56	11.30%	14.0%	32,352
82	T ROWE PRICE GROUP	93.75	2.80	8.18%	11.4%	22,800
83	TAPESTRY	37.52	1.35	9.79%	13.8%	10,467
84	TECHNIPFMC	22.54	0.52	10.03%	12.6%	10,483
85	TELEFLEX	258.43	1.36	12.34%	12.9%	11,712
86	THERMO FISHER SCIENTIFIC	232.98	0.68	12.15%	12.5%	95,882
87	TIFFANY & CO	90.76	2.20	10.79%	13.5%	10,393
88	TJX	47.62	0.78	11.64%	13.5%	59,191
89	TOTAL SYSTEM SERVICES	84.95	0.52	15.95%	16.7%	15,728
90	TRACTOR SUPPLY	88.55	1.24	14.50%	16.1%	10,803
91	UNITED PARCEL SER.'B'	105.05	3.64	11.56%	15.5%	69,229
92	UNIVERSAL HEALTH SVS.'B'	126.95	0.40	11.77%	12.1%	11,127
93	V F	78.25	2.04	12.90%	15.9%	29,070
94	VISA 'A'	135.02	1.00	15.91%	16.8%	241,234
95	WALGREENS BOOTS ALLIANCE	75.66	1.76	10.12%	12.7%	67,919
96	WELLS FARGO & CO	49.97	1.80	10.94%	15.0%	231,738
97	WHIRLPOOL	117.66	4.60	10.23%	14.6%	8,009
98	WILLIS TOWERS WATSON	153.09	2.40	13.32%	15.1%	20,236
99	Market-weighted Average				14.2%	

Notes: In applying the DCF model to the S&P 500, I include in the DCF analysis only those companies in the S&P 500 group which pay a dividend, have a positive growth rate, and have at least three analysts' long-term growth estimates. I also eliminate those twenty-five percent of companies with the highest and lowest DCF results, a decision which had no impact on my CAPM estimate of the cost of equity.

D_0	=	Current dividend per Refinitiv (formerly known as Thomson Reuters).
P_0	=	Average of the monthly high and low stock prices during the three months ending January 2019 per Refinitiv (formerly kown as Thomson Reuters).
g	=	I/B/E/S forecast of future earnings growth January 2019 per Refinitiv (formerly known as Thomson Reuters).
k	=	Cost of equity using the quarterly version of the DCF model shown below:

$$k = \left[\frac{d_0 (1+g)^{\frac{1}{4}}}{P_0} + (1+g)^{\frac{1}{4}} \right]^4 - 1$$

SCHEDULE 6
COMPARABLE EARNINGS VALUE LINE ELECTRIC UTILITIES

	COMPANY	AVERAGE FORECAST ROE 2019 TO 2022-2024	ADJUSTMENT FACTOR	FORECASTED RETURN ON AVERAGE EQUITY
1	ALLETE	8.3%	1.0189	8.5%
2	Alliant Energy	10.5%	0.9999	10.5%
3	Amer. Elec. Power	10.3%	1.0268	10.6%
4	Ameren Corp.	10.5%	1.0275	10.8%
5	AVANGRID Inc.	5.7%	1.0092	5.7%
6	Black Hills	9.5%	1.0403	9.9%
7	CMS Energy Corp.	14.0%	1.0405	14.6%
8	Consol. Edison	8.0%	1.0160	8.1%
9	Dominion Energy	12.3%	1.0501	13.0%
10	DTE Energy	10.7%	1.0371	11.1%
11	Duke Energy	8.2%	1.0131	8.3%
12	Edison Int'l	12.3%	1.0211	12.6%
13	El Paso Electric	8.8%	1.0193	9.0%
14	Entergy Corp.	9.7%	1.0347	10.0%
15	Eversource Energy	9.3%	1.0185	9.5%
16	Exelon Corp.	9.5%	1.0231	9.7%
17	FirstEnergy Corp.	18.0%	1.0564	19.0%
18	Fortis Inc.	8.3%	1.0308	8.6%
19	Hawaiian Elec.	9.5%	1.0240	9.7%
20	IDACORP Inc.	9.2%	1.0181	9.3%
21	MGE Energy	10.0%	1.0510	10.5%
22	NextEra Energy	12.7%	1.0287	13.0%
23	NorthWestern Corp.	9.0%	1.0201	9.2%
24	OGE Energy	10.8%	1.0163	11.0%
25	Otter Tail Corp.	11.3%	1.0495	11.9%
26	Pinnacle West Capital	9.7%	1.0180	9.8%
27	PNM Resources	9.2%	1.0289	9.4%
28	Portland General	8.7%	1.0164	8.8%
29	PPL Corp.	13.2%	1.0347	13.6%
30	Public Serv. Enterprise	11.2%	1.0238	11.4%
31	Sempra Energy	11.0%	1.0479	11.5%
32	Southern Co.	12.5%	1.0234	12.8%
33	WEC Energy Group	11.3%	1.0166	11.5%
34	Xcel Energy Inc.	10.5%	1.0279	10.8%
35	Average			10.7%
	Data from Value Line reports			
	West Value Line	25-Jan-19		
	East Value Line	15-Feb-19		
	Central Value Line	14-Dec-18		

Notes:

I apply my comparable earnings analysis to all investment-grade Value Line electric utilities with sufficient data. AVA, CNP, EVRG, and PCG are not included in the analysis for the following reasons:
AVA: Value Line data are reported prior to the cancellation of the Avista Hydro One merger. Value Line states, “The regulatory commissions in Washington and Idaho rejected the proposed takeover of Avista by Hydro One….The companies have not yet thrown in the towel.”
CNP: Value Line data include costs of anticipated acquisition of Vectren but do not include potential benefits. Value Line states, “It appears as if CenterPoint Energy will complete the acquisition of Vectren in the first quarter of 2019….Our figures include the effects of these financing moves, as well as the merger-related costs, but do not reflect the addition of Vectren because the deal has not yet been completed. Thus, our estimates and projections fall far short of the combined companies' earning power."
EVRG: Value Line does not report sufficient data for the analysis.
PCG: PCG is bankrupt.

The adjustment factor is computed using the formula: 2 x (1 + 5-year change in equity) ÷ (2 + 5-year change in equity). The adjustment factor is required to convert the Value Line ROE data, which are based on year-end equity, to a rate of return on equity based on average equity for the year.

SCHEDULE 7
COMPARABLE EARNINGS LOW-RISK INDUSTRIAL COMPANIES

	COMPANY	AVERAGE FORECAST ROE 2018 TO 2021-2023	ADJUSTMENT FACTOR	FORECASTED RETURN ON AVERAGE EQUITY	BETA	SAFETY RANK	FINANCIAL STRENGTH	DIV'DS DECLARED PER SHARE
1	Nestle SA ADS	19.7%	1.0034	19.7%	0.70	1	A++	2.30
2	Saputo Inc.	14.2%	1.0307	14.6%	0.60	1	A	0.62
3	Smucker (J.M.)	9.2%	1.0131	9.3%	0.70	1	A	3.12
4	Church & Dwight	20.2%	1.0313	20.8%	0.70	1	A+	0.76
5	Procter & Gamble	21.1%	1.0235	21.6%	0.65	1	A++	2.79
6	Walmart Inc.	18.8%	1.0069	19.0%	0.70	1	A++	2.04
7	Average			17.5%				
	Data from Value Line Reports							
	Issue 6, December 21, 2018							
	Issue 10, January 18, 2019							
	Issue 11, January 25, 2019							

Note: The adjustment factor is computed using the formula: 2 x (1 + 5-year change in equity) ÷ (2 + 5-year change in equity). The adjustment factor is required to convert the Value Line ROE data, which are based on year-end equity, to a rate of return on equity based on average equity for the year. High-end results for two identified low-risk industrial companies that met the selection criteria, Coca-Cola and Kellogg, are not included in the data shown above.

SCHEDULE 8
COMPARISON OF DCF EXPECTED RETURN ON AN INVESTMENT IN ELECTRIC UTILITIES TO THE INTEREST RATE ON MOODY'S A-RATED UTILITY BONDS

In this analysis, I compute an electric utility equity risk premium by comparing the DCF estimated cost of equity for an electric utility proxy group to the interest rate on A-rated utility bonds. For each month in my September 1999 through January 2019 study period:

DCF	=	Average DCF-estimated cost of equity on a portfolio of proxy companies;
Bond Yield	=	Yield to maturity on an investment in A-rated utility bonds; and
Risk Premium	=	DCF – Bond yield.

A more detailed description of my *ex ante* risk premium method is contained in Appendix 4.

LINE	DATE	DCF	BOND YIELD	RISK PREMIUM
1	Sep-99	0.1157	0.0793	0.0364
2	Oct-99	0.1161	0.0806	0.0355
3	Nov-99	0.1192	0.0794	0.0398
4	Dec-99	0.1236	0.0814	0.0422
5	Jan-00	0.1221	0.0835	0.0386
6	Feb-00	0.1269	0.0825	0.0444
7	Mar-00	0.1313	0.0828	0.0485
8	Apr-00	0.1237	0.0829	0.0408
9	May-00	0.1227	0.0870	0.0357
10	Jun-00	0.1242	0.0836	0.0406
11	Jul-00	0.1247	0.0825	0.0422
12	Aug-00	0.1228	0.0813	0.0415
13	Sep-00	0.1164	0.0823	0.0341
14	Oct-00	0.1170	0.0814	0.0356
15	Nov-00	0.1191	0.0811	0.0380
16	Dec-00	0.1166	0.0784	0.0382
17	Jan-01	0.1194	0.0780	0.0414
18	Feb-01	0.1203	0.0774	0.0429
19	Mar-01	0.1207	0.0768	0.0439
20	Apr-01	0.1233	0.0794	0.0439
21	May-01	0.1279	0.0799	0.0480
22	Jun-01	0.1285	0.0785	0.0500
23	Jul-01	0.1295	0.0778	0.0517
24	Aug-01	0.1302	0.0759	0.0543
25	Sep-01	0.1321	0.0775	0.0546
26	Oct-01	0.1313	0.0763	0.0550
27	Nov-01	0.1296	0.0757	0.0539
28	Dec-01	0.1292	0.0783	0.0509
29	Jan-02	0.1274	0.0766	0.0508
30	Feb-02	0.1285	0.0754	0.0531
31	Mar-02	0.1248	0.0776	0.0472
32	Apr-02	0.1227	0.0757	0.0470
33	May-02	0.1236	0.0752	0.0484

LINE	DATE	DCF	BOND YIELD	RISK PREMIUM
34	Jun-02	0.1254	0.0741	0.0513
35	Jul-02	0.1337	0.0731	0.0606
36	Aug-02	0.1300	0.0717	0.0583
37	Sep-02	0.1272	0.0708	0.0564
38	Oct-02	0.1291	0.0723	0.0568
39	Nov-02	0.1242	0.0714	0.0528
40	Dec-02	0.1226	0.0707	0.0519
41	Jan-03	0.1195	0.0706	0.0489
42	Feb-03	0.1233	0.0693	0.0540
43	Mar-03	0.1212	0.0679	0.0533
44	Apr-03	0.1170	0.0664	0.0506
45	May-03	0.1095	0.0636	0.0459
46	Jun-03	0.1047	0.0621	0.0426
47	Jul-03	0.1072	0.0657	0.0415
48	Aug-03	0.1064	0.0678	0.0386
49	Sep-03	0.1029	0.0656	0.0373
50	Oct-03	0.1009	0.0643	0.0366
51	Nov-03	0.0985	0.0637	0.0348
52	Dec-03	0.0946	0.0627	0.0319
53	Jan-04	0.0921	0.0615	0.0306
54	Feb-04	0.0916	0.0615	0.0301
55	Mar-04	0.0912	0.0597	0.0315
56	Apr-04	0.0925	0.0635	0.0290
57	May-04	0.0962	0.0662	0.0300
58	Jun-04	0.0961	0.0646	0.0315
59	Jul-04	0.0953	0.0627	0.0326
60	Aug-04	0.0966	0.0614	0.0352
61	Sep-04	0.0951	0.0598	0.0353
62	Oct-04	0.0953	0.0594	0.0359
63	Nov-04	0.0918	0.0597	0.0321
64	Dec-04	0.0920	0.0592	0.0328
65	Jan-05	0.0925	0.0578	0.0347
66	Feb-05	0.0917	0.0561	0.0356
67	Mar-05	0.0918	0.0583	0.0335
68	Apr-05	0.0924	0.0564	0.0360
69	May-05	0.0910	0.0553	0.0356
70	Jun-05	0.0911	0.0540	0.0371
71	Jul-05	0.0899	0.0551	0.0348
72	Aug-05	0.0900	0.0550	0.0350
73	Sep-05	0.0923	0.0552	0.0371
74	Oct-05	0.0934	0.0579	0.0355
75	Nov-05	0.0981	0.0588	0.0393
76	Dec-05	0.0980	0.0580	0.0400
77	Jan-06	0.0980	0.0575	0.0405
78	Feb-06	0.1071	0.0582	0.0489
79	Mar-06	0.1055	0.0598	0.0457
80	Apr-06	0.1075	0.0629	0.0446

LINE	DATE	DCF	BOND YIELD	RISK PREMIUM
81	May-06	0.1087	0.0642	0.0445
82	Jun-06	0.1117	0.0640	0.0477
83	Jul-06	0.1110	0.0637	0.0473
84	Aug-06	0.1072	0.0620	0.0452
85	Sep-06	0.1111	0.0600	0.0511
86	Oct-06	0.1074	0.0598	0.0476
87	Nov-06	0.1078	0.0580	0.0498
88	Dec-06	0.1071	0.0581	0.0490
89	Jan-07	0.1096	0.0596	0.0500
90	Feb-07	0.1085	0.0590	0.0495
91	Mar-07	0.1094	0.0585	0.0509
92	Apr-07	0.1042	0.0597	0.0445
93	May-07	0.1068	0.0599	0.0469
94	Jun-07	0.1123	0.0630	0.0493
95	Jul-07	0.1130	0.0625	0.0505
96	Aug-07	0.1104	0.0624	0.0480
97	Sep-07	0.1078	0.0618	0.0460
98	Oct-07	0.1084	0.0611	0.0473
99	Nov-07	0.1116	0.0597	0.0519
100	Dec-07	0.1132	0.0616	0.0516
101	Jan-08	0.1193	0.0602	0.0591
102	Feb-08	0.1133	0.0621	0.0512
103	Mar-08	0.1170	0.0621	0.0549
104	Apr-08	0.1159	0.0629	0.0530
105	May-08	0.1162	0.0627	0.0535
106	Jun-08	0.1136	0.0638	0.0499
107	Jul-08	0.1172	0.0640	0.0532
108	Aug-08	0.1191	0.0637	0.0554
109	Sep-08	0.1185	0.0649	0.0536
110	Oct-08	0.1280	0.0756	0.0524
111	Nov-08	0.1312	0.0760	0.0552
112	Dec-08	0.1301	0.0654	0.0647
113	Jan-09	0.1241	0.0639	0.0602
114	Feb-09	0.1269	0.0630	0.0639
115	Mar-09	0.1286	0.0642	0.0644
116	Apr-09	0.1266	0.0648	0.0617
117	May-09	0.1242	0.0649	0.0593
118	Jun-09	0.1220	0.0620	0.0600
119	Jul-09	0.1174	0.0597	0.0577
120	Aug-09	0.1158	0.0571	0.0587
121	Sep-09	0.1152	0.0553	0.0599
122	Oct-09	0.1153	0.0555	0.0598
123	Nov-09	0.1196	0.0564	0.0633
124	Dec-09	0.1095	0.0579	0.0516
125	Jan-10	0.1112	0.0577	0.0535
126	Feb-10	0.1091	0.0587	0.0504
127	Mar-10	0.1076	0.0584	0.0492

LINE	DATE	DCF	BOND YIELD	RISK PREMIUM
128	Apr-10	0.1111	0.0582	0.0529
129	May-10	0.1093	0.0552	0.0541
130	Jun-10	0.1088	0.0546	0.0541
131	Jul-10	0.1078	0.0526	0.0552
132	Aug-10	0.1057	0.0501	0.0557
133	Sep-10	0.1059	0.0501	0.0558
134	Oct-10	0.1044	0.0510	0.0534
135	Nov-10	0.1051	0.0536	0.0514
136	Dec-10	0.1053	0.0557	0.0497
137	Jan-11	0.1044	0.0557	0.0487
138	Feb-11	0.1041	0.0568	0.0473
139	Mar-11	0.1044	0.0556	0.0488
140	Apr-11	0.1020	0.0555	0.0465
141	May-11	0.0994	0.0532	0.0462
142	Jun-11	0.1043	0.0526	0.0517
143	Jul-11	0.1019	0.0527	0.0492
144	Aug-11	0.1050	0.0469	0.0581
145	Sep-11	0.1016	0.0448	0.0568
146	Oct-11	0.1032	0.0452	0.0580
147	Nov-11	0.1014	0.0425	0.0589
148	Dec-11	0.1024	0.0435	0.0589
149	Jan-12	0.1016	0.0434	0.0582
150	Feb-12	0.0974	0.0436	0.0538
151	Mar-12	0.0971	0.0448	0.0523
152	Apr-12	0.0994	0.0440	0.0554
153	May-12	0.0981	0.0420	0.0561
154	Jun-12	0.0962	0.0408	0.0554
155	Jul-12	0.0963	0.0393	0.0570
156	Aug-12	0.0972	0.0400	0.0572
157	Sep-12	0.0968	0.0402	0.0566
158	Oct-12	0.0978	0.0391	0.0587
159	Nov-12	0.0935	0.0384	0.0551
160	Dec-12	0.0962	0.0400	0.0562
161	Jan-13	0.0968	0.0415	0.0553
162	Feb-13	0.0956	0.0418	0.0538
163	Mar-13	0.0976	0.0420	0.0556
164	Apr-13	0.0966	0.0400	0.0566
165	May-13	0.0970	0.0417	0.0553
166	Jun-13	0.0990	0.0453	0.0537
167	Jul-13	0.0978	0.0468	0.0510
168	Aug-13	0.0958	0.0473	0.0485
169	Sep-13	0.0950	4.80%	0.0470
170	Oct-13	0.0925	4.70%	0.0455
171	Nov-13	0.0931	4.77%	0.0454
172	Dec-13	0.0931	4.81%	0.0450
173	Jan-14	0.0922	4.63%	0.0459
174	Feb-14	0.0944	4.53%	0.0491

LINE	DATE	DCF	BOND YIELD	RISK PREMIUM
175	Mar-14	0.0983	4.51%	0.0532
176	Apr-14	0.0970	4.41%	0.0529
177	May-14	0.0983	4.26%	0.0557
178	Jun-14	0.0972	4.29%	0.0543
179	Jul-14	0.0966	4.23%	0.0543
180	Aug-14	0.0978	0.0413	0.0565
181	Sep-14	0.0962	0.0424	0.0538
182	Oct-14	0.1013	0.0406	0.0607
183	Nov-14	0.0995	0.0409	0.0586
184	Dec-14	0.0984	0.0395	0.0589
185	Jan-15	0.0972	0.0358	0.0614
186	Feb-15	0.0983	0.0367	0.0616
187	Mar-15	0.0985	0.0374	0.0611
188	Apr-15	0.1005	0.0375	0.0630
189	May-15	0.0983	0.0417	0.0566
190	Jun-15	0.0963	0.0439	0.0524
191	Jul-15	0.0956	0.0440	0.0516
192	Aug-15	0.0966	0.0425	0.0541
193	Sep-15	0.0941	0.0439	0.0502
194	Oct-15	0.0937	0.0429	0.0508
195	Nov-15	0.0938	0.0440	0.0498
196	Dec-15	0.0941	0.0435	0.0506
197	Jan-16	0.0981	0.0427	0.0554
198	Feb-16	0.0977	0.0411	0.0566
199	Mar-16	0.0974	0.0416	0.0558
200	Apr-16	0.0960	0.0400	0.0560
201	May-16	0.0943	0.0393	0.0550
202	Jun-16	0.0940	0.0378	0.0562
203	Jul-16	0.0930	0.0357	0.0573
204	Aug-16	0.0930	0.0359	0.0571
205	Sep-16	0.0932	0.0366	0.0566
206	Oct-16	0.0946	0.0377	0.0569
207	Nov-16	0.0933	0.0408	0.0525
208	Dec-16	0.0940	0.0427	0.0513
209	Jan-17	0.0934	0.0414	0.0520
210	Feb-17	0.0944	0.0418	0.0526
211	Mar-17	0.0942	0.0423	0.0519
212	Apr-17	0.0930	0.0412	0.0518
213	May-17	0.0970	0.0412	0.0558
214	Jun-17	0.0965	0.0394	0.0571
215	Jul-17	0.0956	0.0399	0.0557
216	Aug-17	0.0936	0.0386	0.0550
217	Sep-17	0.0960	0.0387	0.0573
218	Oct-17	0.0963	0.0391	0.0572
219	Nov-17	0.0924	0.0383	0.0541
220	Dec-17	0.0928	0.0379	0.0549
221	Jan-18	0.0954	0.0386	0.0568

LINE	DATE	DCF	BOND YIELD	RISK PREMIUM
222	Feb-18	0.1013	0.0409	0.0604
223	Mar-18	0.0999	0.0413	0.0586
224	Apr-18	0.1009	0.0417	0.0592
225	May-18	0.1000	0.0428	0.0572
226	Jun-18	0.1009	0.0427	0.0582
227	Jul-18	0.0992	0.0427	0.0565
228	Aug-18	0.0989	0.0426	0.0563
229	Sep-18	0.0996	0.0432	0.0564
230	Oct-18	0.1003	0.0445	0.0558
231	Nov-18	0.1016	0.0452	0.0564
232	Dec-18	0.1020	0.0437	0.0583
233	Jan-19	0.1010	0.0435	0.0575

	Ex Ante Risk Premium Cost of Equity		
1	Constant coefficient	0.0851	
2	Bond coefficient	-0.6238	
3	Forecast bond yield =	0.054	
4	Bond coefficient x Bond yield =	(0.0337)	Line 2 (bond coefficient) x Line 3 (bond yield)
5	Ex Ante Risk Premium	0.0514	Line 1+Line 4
6	Forecast bond yield =	0.054	
7	Ex Ante Risk Premium Cost of Equity =	10.54%	Expected risk premium + bond yield

Notes: Utility bond yield information from *Mergent Bond Record* (formerly Moody's). See Appendix 4 for a description of my *ex ante* risk premium approach. DCF results are calculated using a quarterly DCF model.

SCHEDULE 9
COMPARATIVE RETURNS ON S&P 500 STOCK INDEX AND MOODY'S A-RATED UTILITY BONDS 1937 – 2019

LINE	YEAR	S&P 500 STOCK PRICE	STOCK DIVIDEND YIELD	STOCK RETURN	A-RATED BOND PRICE	BOND RETURN	RISK PREMIUM
1	2019	2,607.39	0.0208		$95.81		
2	2018	2,789.80	0.0198	-4.56%	$102.46	-2.59%	-1.97%
3	2017	2,275.12	0.0209	24.71%	$96.13	10.75%	13.97%
4	2016	1,918.60	0.0222	20.80%	$95.48	4.87%	15.93%
5	2015	2,028.18	0.0208	-3.32%	$107.65	-7.59%	4.26%
6	2014	1,822.36	0.0210	13.39%	$89.89	24.20%	-10.81%
7	2013	1,481.11	0.0220	25.24%	$97.45	-3.65%	28.89%
8	2012	1,300.58	0.0214	16.02%	$94.36	7.52%	8.50%
9	2011	1,282.62	0.0185	3.25%	$77.36	27.14%	-23.89%
10	2010	1,123.58	0.0203	16.18%	$75.02	8.44%	7.74%
11	2009	865.58	0.0310	32.91%	$68.43	15.48%	17.43%
12	2008	1,378.76	0.0206	-35.16%	$72.25	0.24%	-35.40%
13	2007	1,424.16	0.0181	-1.38%	$72.91	4.59%	-5.97%
14	2006	1,278.72	0.0183	13.20%	$75.25	2.20%	11.01%
15	2005	1,181.41	0.0177	10.01%	$74.91	5.80%	4.21%
16	2004	1,132.52	0.0162	5.94%	$70.87	11.34%	-5.40%
17	2003	895.84	0.0180	28.22%	$62.26	20.27%	7.95%
18	2002	1,140.21	0.0138	-20.05%	$57.44	15.35%	-35.40%
19	2001	1,335.63	0.0116	-13.47%	$56.40	8.93%	-22.40%
20	2000	1,425.59	0.0118	-5.13%	$52.60	14.82%	-19.95%
21	1999	1,248.77	0.0130	15.46%	$63.03	-10.20%	25.66%
22	1998	963.35	0.0162	31.25%	$62.43	7.38%	23.87%
23	1997	766.22	0.0195	27.68%	$56.62	17.32%	10.36%
24	1996	614.42	0.0231	27.02%	$60.91	-0.48%	27.49%
25	1995	465.25	0.0287	34.93%	$50.22	29.26%	5.68%
26	1994	472.99	0.0269	1.05%	$60.01	-9.65%	10.71%
27	1993	435.23	0.0288	11.56%	$53.13	20.48%	-8.93%
28	1992	416.08	0.0290	7.50%	$49.56	15.27%	-7.77%
29	1991	325.49	0.0382	31.65%	$44.84	19.44%	12.21%
30	1990	339.97	0.0341	-0.85%	$45.60	7.11%	-7.96%
31	1989	285.41	0.0364	22.76%	$43.06	15.18%	7.58%
32	1988	250.48	0.0366	17.61%	$40.10	17.36%	0.25%
33	1987	264.51	0.0317	-2.13%	$48.92	-9.84%	7.71%
34	1986	208.19	0.0390	30.95%	$39.98	32.36%	-1.41%
35	1985	171.61	0.0451	25.83%	$32.57	35.05%	-9.22%
36	1984	166.39	0.0427	7.41%	$31.49	16.12%	-8.72%
37	1983	144.27	0.0479	20.12%	$29.41	20.65%	-0.53%
38	1982	117.28	0.0595	28.96%	$24.48	36.48%	-7.51%
39	1981	132.97	0.0480	-7.00%	$29.37	-3.01%	-3.99%
40	1980	110.87	0.0541	25.34%	$34.69	-3.81%	29.16%

LINE	YEAR	S&P 500 STOCK PRICE	STOCK DIVIDEND YIELD	STOCK RETURN	A-RATED BOND PRICE	BOND RETURN	RISK PREMIUM
41	1979	99.71	0.0533	16.52%	$43.91	-11.89%	28.41%
42	1978	90.25	0.0532	15.80%	$49.09	-2.40%	18.20%
43	1977	103.80	0.0399	-9.06%	$50.95	4.20%	-13.27%
44	1976	96.86	0.0380	10.96%	$43.91	25.13%	-14.17%
45	1975	72.56	0.0507	38.56%	$41.76	14.75%	23.81%
46	1974	96.11	0.0364	-20.86%	$52.54	-12.91%	-7.96%
47	1973	118.40	0.0269	-16.14%	$58.51	-3.37%	-12.77%
48	1972	103.30	0.0296	17.58%	$56.47	10.69%	6.89%
49	1971	93.49	0.0332	13.81%	$53.93	12.13%	1.69%
50	1970	90.31	0.0356	7.08%	$50.46	14.81%	-7.73%
51	1969	102.00	0.0306	-8.40%	$62.43	-12.76%	4.36%
52	1968	95.04	0.0313	10.45%	$66.97	-0.81%	11.26%
53	1967	84.45	0.0351	16.05%	$78.69	-9.81%	25.86%
54	1966	93.32	0.0302	-6.48%	$86.57	-4.48%	-2.00%
55	1965	86.12	0.0299	11.35%	$91.40	-0.91%	12.26%
56	1964	76.45	0.0305	15.70%	$92.01	3.68%	12.02%
57	1963	65.06	0.0331	20.82%	$93.56	2.61%	18.20%
58	1962	69.07	0.0297	-2.84%	$89.60	8.89%	-11.73%
59	1961	59.72	0.0328	18.94%	$89.74	4.29%	14.64%
60	1960	58.03	0.0327	6.18%	$84.36	11.13%	-4.95%
61	1959	55.62	0.0324	7.57%	$91.55	-3.49%	11.06%
62	1958	41.12	0.0448	39.74%	$101.22	-5.60%	45.35%
63	1957	45.43	0.0431	-5.18%	$100.70	4.49%	-9.67%
64	1956	44.15	0.0424	7.14%	$113.00	-7.35%	14.49%
65	1955	35.60	0.0438	28.40%	$116.77	0.20%	28.20%
66	1954	25.46	0.0569	45.52%	$112.79	7.07%	38.45%
67	1953	26.18	0.0545	2.70%	$114.24	2.24%	0.46%
68	1952	24.19	0.0582	14.05%	$113.41	4.26%	9.79%
69	1951	21.21	0.0634	20.39%	$123.44	-4.89%	25.28%
70	1950	16.88	0.0665	32.30%	$125.08	1.89%	30.41%
71	1949	15.36	0.0620	16.10%	$119.82	7.72%	8.37%
72	1948	14.83	0.0571	9.28%	$118.50	4.49%	4.79%
73	1947	15.21	0.0449	1.99%	$126.02	-2.79%	4.79%
74	1946	18.02	0.0356	-12.03%	$126.74	2.59%	-14.63%
75	1945	13.49	0.0460	38.18%	$119.82	9.11%	29.07%
76	1944	11.85	0.0495	18.79%	$119.82	3.34%	15.45%
77	1943	10.09	0.0554	22.98%	$118.50	4.49%	18.49%
78	1942	8.93	0.0788	20.87%	$117.63	4.14%	16.73%
79	1941	10.55	0.0638	-8.98%	$116.34	4.55%	-13.52%
80	1940	12.30	0.0458	-9.65%	$112.39	7.08%	-16.73%
81	1939	12.50	0.0349	1.89%	$105.75	10.05%	-8.16%
82	1938	11.31	0.0784	18.36%	$99.83	9.94%	8.42%
83	1937	17.59	0.0434	-31.36%	$103.18	0.63%	-31.99%
84	Risk Premium			11.21%		6.56%	4.65%

Note: See Appendix 5 for an explanation of how stock and bond returns are derived and the source of the data presented.

SCHEDULE 10
COMPARATIVE RETURNS ON S&P UTILITY STOCK INDEX AND MOODY'S A-RATED UTILITY BONDS 1937 – 2019

LINE	YEAR	S&P UTILITY STOCK PRICE	STOCK DIVIDEND YIELD	STOCK RETURN	A-RATED BOND PRICE	BOND RETURN	RISK PREMIUM
1	2019				$95.81		
2	2018			3.67%	$102.46	-2.59%	6.26%
3	2017			11.72%	$96.13	10.75%	0.97%
4	2016			17.44%	$95.48	4.87%	12.57%
5	2015			-3.90%	$107.65	-7.59%	3.69%
6	2014			28.91%	$89.89	24.20%	4.71%
7	2013			13.01%	$97.45	-3.65%	16.66%
8	2012			2.09%	$94.36	7.52%	-5.43%
9	2011			19.99%	$77.36	27.14%	-7.15%
10	2010			7.04%	$75.02	8.44%	-1.40%
11	2009			10.71%	$68.43	15.48%	-4.77%
12	2008			-25.90%	$72.25	0.24%	-26.14%
13	2007			16.56%	$72.91	4.59%	11.96%
14	2006			20.76%	$75.25	2.20%	18.56%
15	2005			16.05%	$74.91	5.80%	10.25%
16	2004			22.84%	$70.87	11.34%	11.50%
17	2003			23.48%	$62.26	20.27%	3.21%
18	2002			-14.73%	$57.44	15.35%	-30.08%
19	2001	307.70	0.0287	-17.90%	$56.40	8.93%	-26.83%
20	2000	239.17	0.0413	32.78%	$52.60	14.82%	17.96%
21	1999	253.52	0.0394	-1.72%	$63.03	-10.20%	8.48%
22	1998	228.61	0.0457	15.47%	$62.43	7.38%	8.09%
23	1997	201.14	0.0492	18.58%	$56.62	17.32%	1.26%
24	1996	202.57	0.0454	3.83%	$60.91	-0.48%	4.31%
25	1995	153.87	0.0584	37.49%	$50.22	29.26%	8.23%
26	1994	168.70	0.0496	-3.83%	$60.01	-9.65%	5.82%
27	1993	159.79	0.0537	10.95%	$53.13	20.48%	-9.54%
28	1992	149.70	0.0572	12.46%	$49.56	15.27%	-2.81%
29	1991	138.38	0.0607	14.25%	$44.84	19.44%	-5.19%
30	1990	146.04	0.0558	0.33%	$45.60	7.11%	-6.78%
31	1989	114.37	0.0699	34.68%	$43.06	15.18%	19.51%
32	1988	106.13	0.0704	14.80%	$40.10	17.36%	-2.55%
33	1987	120.09	0.0588	-5.74%	$48.92	-9.84%	4.10%
34	1986	92.06	0.0742	37.87%	$39.98	32.36%	5.51%
35	1985	75.83	0.0860	30.00%	$32.57	35.05%	-5.04%
36	1984	68.50	0.0925	19.95%	$31.49	16.12%	3.83%
37	1983	61.89	0.0948	20.16%	$29.41	20.65%	-0.49%
38	1982	51.81	0.1074	30.20%	$24.48	36.48%	-6.28%
39	1981	52.01	0.0978	9.40%	$29.37	-3.01%	12.41%
40	1980	50.26	0.0953	13.01%	$34.69	-3.81%	16.83%
41	1979	50.33	0.0893	8.79%	$43.91	-11.89%	20.68%

LINE	YEAR	S&P UTILITY STOCK PRICE	STOCK DIVIDEND YIELD	STOCK RETURN	A-RATED BOND PRICE	BOND RETURN	RISK PREMIUM
42	1978	52.40	0.0791	3.96%	$49.09	-2.40%	6.36%
43	1977	54.01	0.0714	4.16%	$50.95	4.20%	-0.04%
44	1976	46.99	0.0776	22.70%	$43.91	25.13%	-2.43%
45	1975	38.19	0.0920	32.24%	$41.76	14.75%	17.49%
46	1974	48.60	0.0713	-14.29%	$52.54	-12.91%	-1.38%
47	1973	60.01	0.0556	-13.45%	$58.51	-3.37%	-10.08%
48	1972	60.19	0.0542	5.12%	$56.47	10.69%	-5.57%
49	1971	63.43	0.0504	-0.07%	$53.93	12.13%	-12.19%
50	1970	55.72	0.0561	19.45%	$50.46	14.81%	4.64%
51	1969	68.65	0.0445	-14.38%	$62.43	-12.76%	-1.62%
52	1968	68.02	0.0435	5.28%	$66.97	-0.81%	6.08%
53	1967	70.63	0.0392	0.22%	$78.69	-9.81%	10.03%
54	1966	74.50	0.0347	-1.72%	$86.57	-4.48%	2.76%
55	1965	75.87	0.0315	1.34%	$91.40	-0.91%	2.25%
56	1964	67.26	0.0331	16.11%	$92.01	3.68%	12.43%
57	1963	63.35	0.0330	9.47%	$93.56	2.61%	6.86%
58	1962	62.69	0.0320	4.25%	$89.60	8.89%	-4.64%
59	1961	52.73	0.0358	22.47%	$89.74	4.29%	18.18%
60	1960	44.50	0.0403	22.52%	$84.36	11.13%	11.39%
61	1959	43.96	0.0377	5.00%	$91.55	-3.49%	8.49%
62	1958	33.30	0.0487	36.88%	$101.22	-5.60%	42.48%
63	1957	32.32	0.0487	7.90%	$100.70	4.49%	3.41%
64	1956	31.55	0.0472	7.16%	$113.00	-7.35%	14.51%
65	1955	29.89	0.0461	10.16%	$116.77	0.20%	9.97%
66	1954	25.51	0.0520	22.37%	$112.79	7.07%	15.30%
67	1953	24.41	0.0511	9.62%	$114.24	2.24%	7.38%
68	1952	22.22	0.0550	15.36%	$113.41	4.26%	11.10%
69	1951	20.01	0.0606	17.10%	$123.44	-4.89%	21.99%
70	1950	20.20	0.0554	4.60%	$125.08	1.89%	2.71%
71	1949	16.54	0.0570	27.83%	$119.82	7.72%	20.10%
72	1948	16.53	0.0535	5.41%	$118.50	4.49%	0.92%
73	1947	19.21	0.0354	-10.41%	$126.02	-2.79%	-7.62%
74	1946	21.34	0.0298	-7.00%	$126.74	2.59%	-9.59%
75	1945	13.91	0.0448	57.89%	$119.82	9.11%	48.79%
76	1944	12.10	0.0569	20.65%	$119.82	3.34%	17.31%
77	1943	9.22	0.0621	37.45%	$118.50	4.49%	32.96%
78	1942	8.54	0.0940	17.36%	$117.63	4.14%	13.22%
79	1941	13.25	0.0717	-28.38%	$116.34	4.55%	-32.92%
80	1940	16.97	0.0540	-16.52%	$112.39	7.08%	-23.60%
81	1939	16.05	0.0553	11.26%	$105.75	10.05%	1.21%
82	1938	14.30	0.0730	19.54%	$99.83	9.94%	9.59%
83	1937	24.34	0.0432	-36.93%	$103.18	0.63%	-37.55%
84	Risk Premium			10.55%		6.56%	3.99%

Note: See Appendix 5 for an explanation of how stock and bond returns are derived and the source of the data presented. Standard & Poor's discontinued its previous S&P Utilities Index in December 2001. Thus, in this study, the stock returns beginning in 2002 are based on the total returns for the EEI Index of U.S. shareholder-owned electric utilities, as reported by EEI on its website.
http://www.eei.org/whatwedo/DataAnalysis/IndusFinanAnalysis/Pages/QtrlyFinancialUpdates.aspx

APPENDIX 1
QUALIFICATIONS OF JAMES H. VANDER WEIDE, PH.D.

3606 Stoneybrook Drive
Durham, NC 27705
TEL. 919.383.6659 OR 919.383.1057
jim.vanderweide@duke.edu

James H. Vander Weide is President of Financial Strategy Associates, a consulting firm that provides financial and economic consulting services, including cost of capital and valuation studies, to corporate clients. Dr. Vander Weide holds a Ph.D. in Finance from Northwestern University and a Bachelor of Arts in Economics from Cornell University. After receiving his Ph.D. in Finance, Dr. Vander Weide joined the faculty at Duke University, the Fuqua School of Business, and was named Assistant Professor, Associate Professor, Professor, and then Research Professor of Finance and Economics.

As a Professor at Duke University and the Fuqua School of Business, Dr. Vander Weide has published research in the areas of finance and economics and taught courses in corporate finance, investment management, management of financial institutions, statistics, economics, operations research, and the theory of public utility pricing. Dr. Vander Weide has been active in executive education at Duke and Duke Corporate Education, leading executive development seminars on topics including financial analysis, cost of capital, creating shareholder value, mergers and acquisitions, capital budgeting, measuring corporate performance, and valuation. In addition, Dr. Vander Weide designed and served as Program Director for several executive education programs, including the Advanced Management Program, Competitive Strategies in Telecommunications, and the Duke Program for Manager Development for managers from the former Soviet Union. He is now retired from his teaching responsibilities at Duke.

As an expert financial economist and industry expert, Dr. Vander Weide has participated in more than five hundred regulatory and legal proceedings, appearing in United States courts and federal and state or provincial proceedings in the United States and Canada. He has testified as an expert witness on the cost of capital, competition, risk, incentive regulation, forward-looking economic cost, economic pricing guidelines, valuation, and other financial and economic issues. His clients include investor-owned electric, gas, and water utilities, natural gas pipelines, oil pipelines, telecommunications companies, and insurance companies.

Publications

Dr. Vander Weide has written research papers on such topics as portfolio management, capital budgeting, investments, the effect of regulation on the performance of public utilities, and cash management. His articles have been published in *American Economic Review, Journal of Finance, Journal of Financial and Quantitative Analysis, Management Science, Financial Management, Journal of Portfolio Management, International Journal of Industrial Organization, Journal of Bank Research, Journal of Accounting Research, Journal of Cash Management, Atlantic Economic Journal, Journal of Economics and Business,* and *Computers and Operations Research*. He has written a book entitled *Managing Corporate Liquidity: An Introduction to Working Capital Management* published by John Wiley and Sons, Inc.; and he has written a chapter titled "Financial Management in the Short Run" for *The Handbook of Modern Finance*, and a chapter titled "Principles for Lifetime Portfolio Selection: Lessons from Portfolio Theory" for *The Handbook of Portfolio Construction: Contemporary Applications of Markowitz Techniques. The Handbook of Portfolio*

Construction is a peer-reviewed collection of research papers by notable scholars on portfolio optimization, published in 2010 in honor of Nobel Prize winner Harry Markowitz.

Professional Consulting Experience

Dr. Vander Weide has provided financial and economic consulting services to firms in the electric, gas, insurance, oil and gas pipeline, telecommunications, and water industries for more than thirty years. He has testified on the cost of capital, competition, risk, incentive regulation, forward-looking economic cost, economic pricing guidelines, valuation, and other financial and economic issues in more than five hundred cases before the Federal Energy Regulatory Commission, the National Energy Board (Canada), the Federal Communications Commission, the Canadian Radio-Television and Telecommunications Commission, the National Telecommunications and Information Administration, the United States Tax Court, the public service commissions of forty-five states and the District of Columbia, four Canadian provinces, the insurance commissions of five states, the Iowa State Board of Tax Review, and the North Carolina Property Tax Commission. In addition, he has testified as an expert witness in proceedings before numerous federal district courts, including the United States District Court for the District of Nebraska; the United States District Court for the District of New Hampshire; the United States District Court for the District of Northern Illinois; the United States District Court for the Eastern District of North Carolina; the Montana Second Judicial District Court, Silver Bow County; the United States District Court for the Northern District of California; the Superior Court, North Carolina; the United States Bankruptcy Court for the Southern District of West Virginia; the United States District Court for the Eastern District of Michigan; and the Supreme Court of the State of New York. Dr. Vander Weide testified in thirty states on issues relating to the pricing of unbundled network elements and universal service cost studies and consulted with Bell Canada, Deutsche Telekom, and Telefónica on similar issues. Dr. Vander Weide has provided consulting and expert witness testimony to the following companies:

ELECTRIC, GAS, PIPELINE, WATER COMPANIES	
Alcoa Power Generating, Inc.	MidAmerican Energy and subsidiaries
Alliant Energy and subsidiaries	National Fuel Gas
AltaLink, L.P.	Nevada Power Company
Ameren	Newfoundland Power Inc.
American Water Works	NICOR
Atmos Energy and subsidiaries	North Carolina Natural Gas
BP p.l.c.	North Shore Gas
Buckeye Partners, L.P.	Northern Natural Gas Company
Central Illinois Public Service	NOVA Gas Transmission Ltd.
Citizens Utilities	PacifiCorp
Consolidated Edison and subsidiaries	Peoples Energy and its subsidiaries
Consolidated Natural Gas and subsidiaries	PG&E
Dominion Resources and subsidiaries	Plains All American Pipeline, L.P.
Duke Energy and subsidiaries	Progress Energy and subsidiaries
Empire District Electric and subsidiaries	PSE&G
EPCOR Distribution & Transmission Inc.	Public Service Company of North Carolina
EPCOR Energy Alberta Inc.	Sempra Energy/San Diego Gas and Electric
FortisAlberta Inc.	South Carolina Electric and Gas

ELECTRIC, GAS, PIPELINE, WATER COMPANIES	
FortisBC Utilities	Southern Company and subsidiaries
Hope Natural Gas	Spectra Energy
Iberdrola Renewables	Tennessee-American Water Company
Interstate Power Company	The Peoples Gas, Light and Coke Co.
Iowa Southern	Trans Québec & Maritimes Pipeline Inc.
Iowa-American Water Company	TransCanada
Iowa-Illinois Gas and Electric	Union Gas
Kentucky Power Company	United Cities Gas Company
Kentucky-American Water Company	Virginia-American Water Company
Kinder Morgan Energy Partners	West Virginia-American Water Company
Maritimes & Northeast Pipeline	Westcoast Energy Inc.
	Wisconsin Energy Corporation
	Xcel Energy

TELECOMMUNICATIONS COMPANIES	
ALLTEL and subsidiaries	Phillips County Cooperative Tel. Co.
Ameritech (now AT&T new)	Pine Drive Cooperative Telephone Co.
AT&T (old)	Roseville Telephone Company (SureWest)
Bell Canada/Nortel	SBC Communications (now AT&T new)
BellSouth and subsidiaries	Sherburne Telephone Company
Centel and subsidiaries	Siemens
Cincinnati Bell (Broadwing)	Southern New England Telephone
Cisco Systems	Sprint/United and subsidiaries
Citizens Telephone Company	Telefónica
Concord Telephone Company	Tellabs, Inc.
Contel and subsidiaries	The Stentor Companies
Deutsche Telekom	U S West (Qwest)
GTE and subsidiaries (now Verizon)	Union Telephone Company
Heins Telephone Company	United States Telephone Association
JDS Uniphase	Valor Telecommunications (Windstream)
Lucent Technologies	Verizon (Bell Atlantic) and subsidiaries
Minnesota Independent Equal Access Corp.	Woodbury Telephone Company
NYNEX and subsidiaries (Verizon)	
Pacific Telesis and subsidiaries	

INSURANCE COMPANIES
Allstate
North Carolina Rate Bureau
United Services Automobile Association (USAA)
The Travelers Indemnity Company
Gulf Insurance Company

Other Professional Experience

Dr. Vander Weide has conducted in-house seminars and training sessions on topics such as creating shareholder value, financial analysis, competitive strategy, cost of capital, real options, financial strategy, managing growth, mergers and acquisitions, valuation, measuring corporate performance, capital budgeting, cash management, and financial planning. Among the firms for whom he has designed and taught tailored programs and training sessions are ABB Asea Brown Boveri, Accenture, Allstate, Ameritech, AT&T, Bell Atlantic/Verizon, BellSouth, Progress Energy/Carolina Power & Light, Contel, Fisons, GlaxoSmithKline, GTE, Lafarge, MidAmerican Energy, New Century Energies, Norfolk Southern, Pacific Bell Telephone, The Rank Group, Siemens, Southern New England Telephone, TRW, and Wolseley Plc. Dr. Vander Weide has also hosted a nationally prominent conference/workshop on estimating the cost of capital. In 1989, at the request of Mr. Fuqua, Dr. Vander Weide designed the Duke Program for Manager Development for managers from the former Soviet Union, the first in the United States designed exclusively for managers from Russia and the former Soviet republics.

Early in his career, Dr. Vander Weide helped found University Analytics, Inc., one of the fastest growing small firms in the country at that time. As an officer at University Analytics, he designed cash management models, databases, and software used by most major U.S. banks in consulting with their corporate clients. Having sold his interest in University Analytics, Dr. Vander Weide now concentrates on strategic and financial consulting, academic research, and executive education.

PUBLICATIONS
JAMES H. VANDER WEIDE

The Lock-Box Location Problem: a Practical Reformulation, *Journal of Bank Research*, Summer, 1974, pp. 92-96 (with S. Maier). Reprinted in *Management Science in Banking*, edited by K. J. Cohen and S. E. Gibson, Warren, Gorham and Lamont, 1978.

A Finite Horizon Dynamic Programming Approach to the Telephone Cable Layout Problem, *Conference Record*, 1976 International Conference on Communications (with S. Maier and C. Lam).

A Note on the Optimal Investment Policy of the Regulated Firm, *Atlantic Economic Journal*, Fall, 1976 (with D. Peterson).

A Unified Location Model for Cash Disbursements and Lock-Box Collections, *Journal of Bank Research*, Summer, 1976 (with S. Maier). Reprinted in *Management Science in Banking*, edited by K. J. Cohen and S. E. Gibson, Warren Gorham and Lamont, 1978. Also reprinted in *Readings on the Management of Working Capital*, edited by K. V. Smith, West Publishing Company, 1979.

Capital Budgeting in the Decentralized Firm,' *Management Science*, Vol. 23, No. 4, December 1976, pp. 433-443 (with S. Maier).

A Monte Carlo Investigation of Characteristics of Optimal Geometric Mean Portfolios, *Journal of Financial and Quantitative Analysis*, June, 1977, pp. 215-233 (with S. Maier and D. Peterson).

A Strategy which Maximizes the Geometric Mean Return on Portfolio Investments, *Management Science*, June, 1977, Vol. 23, No. 10, pp. 1117-1123 (with S. Maier and D. Peterson).

A Decision Analysis Approach to the Computer Lease-Purchase Decision, *Computers and Operations Research*, Vol. 4, No. 3, September, 1977, pp. 167-172 (with S. Maier).

A Practical Approach to Short-run Financial Planning, *Financial Management*, Winter, 1978 (with S. Maier). Reprinted in *Readings on the Management of Working Capital*, edited by K. V. Smith, West Publishing Company, 1979.

Effectiveness of Regulation in the Electric Utility Industry,' *Journal of Economics and Business*, May, 1979 (with F. Tapon).

On the Decentralized Capital Budgeting Problem Under Uncertainty, *Management Science*, September 1979 (with B. Obel).

Expectations Data and the Predictive Value of Interim Reporting: A Comment, *Journal of Accounting Research*, Spring 1980 (with L. D. Brown, J. S. Hughes, and M. S. Rozeff).

General Telephone's Experience with a Short-run Financial Planning Model, *Cash Management Forum*, June 1980, Vol. 6, No. 1 (with J. Austin and S. Maier).

Deregulation and Oligopolistic Price-Quality Rivalry, *American Economic Review*, March 1981 (with J. Zalkind).

Forecasting Disbursement Float, *Financial Management*, Spring 1981 (with S. Maier and D. Robinson).

Recent Developments in Management Science in Banking, *Management Science*, October 1981 (with K. Cohen and S. Maier).

Incentive Considerations in the Reporting of Leveraged Leases, *Journal of Bank Research*, April 1982 (with J. S. Hughes).

A Decision-Support System for Managing a Short-term Financial Instrument Portfolio, *Journal of Cash Management*, March 1982 (with S. Maier).

An Empirical Bayes Estimate of Market Risk, *Management Science*, July 1982 (with S. Maier and D. Peterson).

The Bond Scheduling Problem of the Multi-subsidiary Holding Company, *Management Science*, July 1982 (with K. Baker).

Deregulation and Locational Rents in Banking: a Comment, *Journal of Bank Research*, Summer 1983.

What Lockbox and Disbursement Models Really Do, *Journal of Finance*, May 1983 (with S. Maier).

Financial Management in the Short Run, *Handbook of Modern Finance*, edited by Dennis Logue, published by Warren, Gorham, & Lamont, Inc., New York, 1984.

Managing Corporate Liquidity: an Introduction to Working Capital Management, John Wiley and Sons, 1984 (with S. Maier).

Measuring Investors' Growth Expectations: Analysts vs. History, *The Journal of Portfolio Management*, Spring 1988 (with W. Carleton).

Entry Auctions and Strategic Behavior under Cross-Market Price Constraints, *International Journal of Industrial Organization*, 20 (2002) 611-629 (with J. Anton and N. Vettas).

Principles for Lifetime Portfolio Selection: Lessons from Portfolio Theory, *Handbook of Portfolio Construction: Contemporary Applications of Markowitz Techniques*, John B. Guerard, (Ed.), Springer, 2009.

APPENDIX 2
DERIVATION OF THE QUARTERLY DCF MODEL

The simple DCF Model assumes that a firm pays dividends only at the end of each year. Since firms in fact pay dividends quarterly and investors appreciate the time value of money, the annual version of the DCF Model generally underestimates the value investors are willing to place on the firm's expected future dividend stream. In these workpapers, we review two alternative formulations of the DCF Model that allow for the quarterly payment of dividends.

When dividends are assumed to be paid annually, the DCF Model suggests that the current price of the firm's stock is given by the expression:

$$P_0 = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \ldots + \frac{D_n + P_n}{(1+k)^n} \quad \textbf{(1)}$$

where

P_0	=	current price per share of the firm's stock,
$D_1, D_2,\ldots,D_n$	=	expected annual dividends per share on the firm's stock,
P_n	=	price per share of stock at the time investors expect to sell the stock, and
k	=	return investors expect to earn on alternative investments of the same risk, i.e., the investors' required rate of return.

Unfortunately, expression (1) is rather difficult to analyze, especially for the purpose of estimating k. Thus, most analysts make a number of simplifying assumptions. First, they assume that dividends are expected to grow at the constant rate g into the indefinite future. Second, they assume that the stock price at time n is simply the present value of all dividends expected in periods subsequent to n. Third, they assume that the investors' required rate of return, k, exceeds the expected dividend growth rate g. Under the above simplifying assumptions, a firm's stock price may be written as the following sum:

$$P_0 = \frac{D_0(1+g)}{(1+k)} + \frac{D_0(1+g)^2}{(1+k)^2} + \frac{D_0(1+g)^3}{(1+k)^3} + \ldots, \qquad (2)$$

where the three dots indicate that the sum continues indefinitely.

As we shall demonstrate shortly, this sum may be simplified to:

$$P_0 = \frac{D_0(1+g)}{(k-g)}$$

First, however, we need to review the very useful concept of a geometric progression.

Geometric Progression

Consider the sequence of numbers 3, 6, 12, 24,..., where each number after the first is obtained by multiplying the preceding number by the factor 2. Obviously, this sequence of numbers may also be expressed as the sequence 3, 3 x 2, 3 x 2^2, 3 x 2^3, etc. This sequence is an example of a geometric progression.

Definition: A geometric progression is a sequence in which each term after the first is obtained by multiplying some fixed number, called the common ratio, by the preceding term.

A general notation for geometric progressions is: a, the first term, r, the common ratio, and n, the number of terms. Using this notation, any geometric progression may be represented by the sequence:

$$a, ar, ar^2, ar^3, \ldots, ar^{n-1}.$$

In studying the DCF Model, we will find it useful to have an expression for the sum of n terms of a geometric progression. Call this sum S_n. Then

$$S_n = a + ar + \ldots + ar^{n-1}. \qquad (3)$$

However, this expression can be simplified by multiplying both sides of equation (3) by r and then subtracting the new equation from the old. Thus,

$$rS_n = ar + ar^2 + ar^3 + \ldots + ar^n$$

and

$$S_n - rS_n = a - ar^n \ ,$$

or

$$(1 - r)\, S_n = a\,(1 - r^n)\ .$$

Solving for S_n, we obtain:

$$S_n = \frac{a(1 - r^n)}{(1 - r)} \qquad \textbf{(4)}$$

as a simple expression for the sum of n terms of a geometric progression. Furthermore, if $|r| < 1$, then S_n is finite, and as n approaches infinity, S_n approaches a ÷ (1-r). Thus, for a geometric progression with an infinite number of terms and $|r| < 1$, equation (4) becomes:

$$S = \frac{a}{1 - r} \qquad \textbf{(5)}$$

<u>Application to DCF Model</u>

Comparing equation (2) with equation (3), we see that the firm's stock price (under the DCF assumption) is the sum of an infinite geometric progression with the first term

$$a = \frac{D_0(1 + g)}{(1 + k)}$$

and common factor

$$r = \frac{(1 + g)}{(1 + k)}$$

Applying equation (5) for the sum of such a geometric progression, we obtain

$$S = a \bullet \frac{1}{(1 - r)} = \frac{D_0(1 + g)}{(1 + k)} \bullet \frac{1}{1 - \frac{1 + g}{1 + k}} = \frac{D_0(1 + g)}{(1 + k)} \bullet \frac{1 + k}{k - g} = \frac{D_0(1 + g)}{k - g}$$

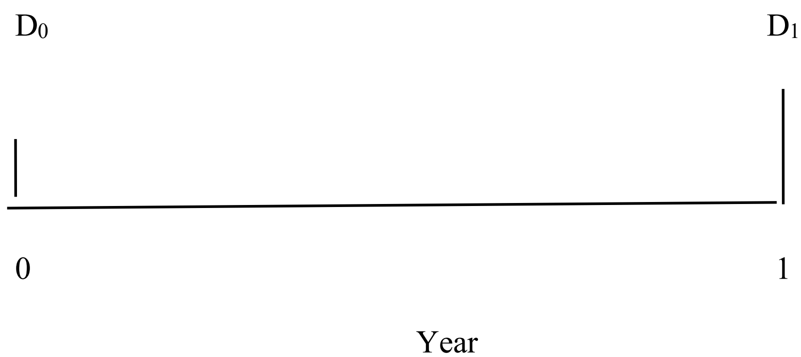
as we suggested earlier.

Quarterly DCF Model

The Annual DCF Model assumes that dividends grow at an annual rate of g% per year (see Figure 1).

Figure 1

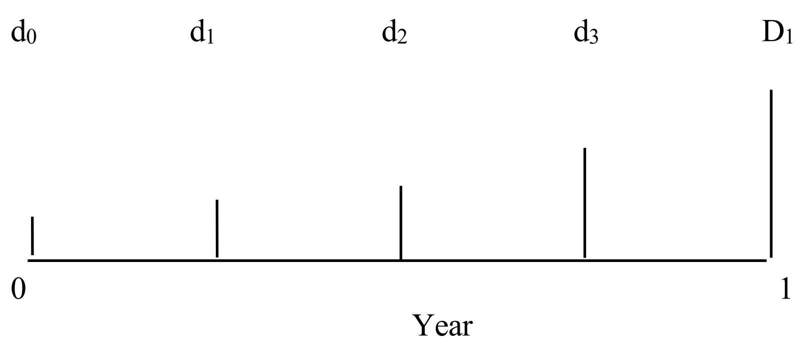
Annual DCF Model



$D_0 = 4d_0$ $D_1 = D_0(1 + g)$

Figure 2

Quarterly DCF Model (Constant Growth Version)



$d_1 = d_0(1+g)^{.25}$ $d_2 = d_0(1+g)^{.50}$

$d_3 = d_0(1+g)^{.75}$ $d_4 = d_0(1+g)$

In the Quarterly DCF Model, it is natural to assume that quarterly dividend payments differ from the preceding quarterly dividend by the factor $(1 + g)^{.25}$, where g is expressed in terms of percent per year and the decimal .25 indicates that the growth has only occurred for one quarter of the year. (See Figure 2.) Using this assumption, along with the assumption of constant growth and ***k*** > ***g***, we obtain a new expression for the firm's stock price, which takes account of the quarterly payment of dividends. This expression is:

$$P_0 = \frac{d_0(1+g)^{\frac{1}{4}}}{(1+k)^{\frac{1}{4}}} + \frac{d_0(1+g)^{\frac{2}{4}}}{(1+k)^{\frac{2}{4}}} + \frac{d_0(1+g)^{\frac{3}{4}}}{(1+k)^{\frac{3}{4}}} + \dots \qquad \textbf{(6)}$$

where d_0 is the last quarterly dividend payment, rather than the last annual dividend payment. (We use a lower case d to remind the reader that this is not the annual dividend.)

Although equation (6) looks formidable at first glance, it too can be greatly simplified using the formula [equation (4)] for the sum of an infinite geometric progression. As the reader can easily verify, equation (6) can be simplified to:

$$P_0 = \frac{d_0(1+g)^{\frac{1}{4}}}{(1+k)^{\frac{1}{4}} - (1+g)^{\frac{1}{4}}} \qquad \textbf{(7)}$$

Solving equation (7) for *k*, we obtain a DCF formula for estimating the cost of equity under the quarterly dividend assumption:

$$k = \left[\frac{d_0(1+g)^{\frac{1}{4}}}{P_0} + (1+g)^{\frac{1}{4}} \right]^4 - 1 \qquad \textbf{(8)}$$

An Alternative Quarterly DCF Model

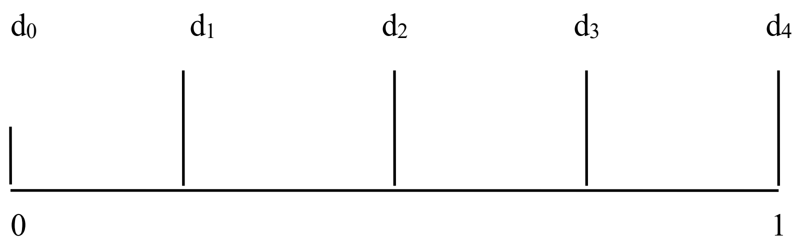
Although the constant growth Quarterly DCF Model [equation (8)] allows for the quarterly timing of dividend payments, it does require the assumption that the firm increases its dividend payments each quarter. Since this assumption is difficult for some analysts to accept, we now discuss a second Quarterly DCF Model that allows for constant quarterly dividend payments within each dividend year.

Assume then that the firm pays dividends quarterly and that each dividend payment is constant for four consecutive quarters. There are four cases to consider, with each case distinguished by varying assumptions about where we are evaluating the firm in relation to the time of its next dividend increase. (See Figure 3.)

Figure 3

Quarterly DCF Model (Constant Dividend Version)

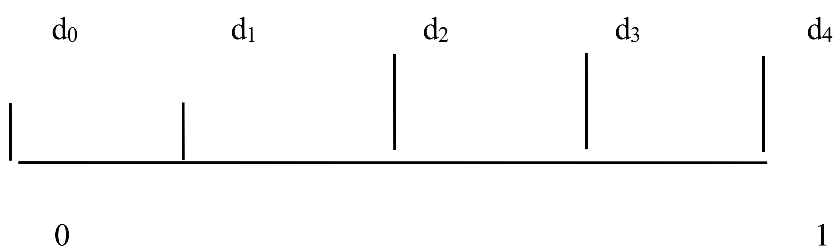
Case 1



Year

$$d_1 = d_2 = d_3 = d_4 = d_0(1+g)$$

Case 2



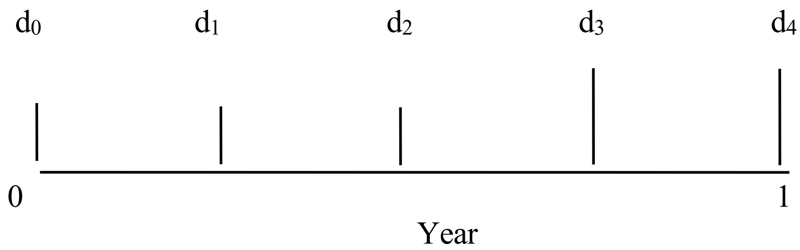
Year

$$d_1 = d_0$$

$$d_2 = d_3 = d_4 = d_0(1+g)$$

<u>Figure 3</u> (continued)

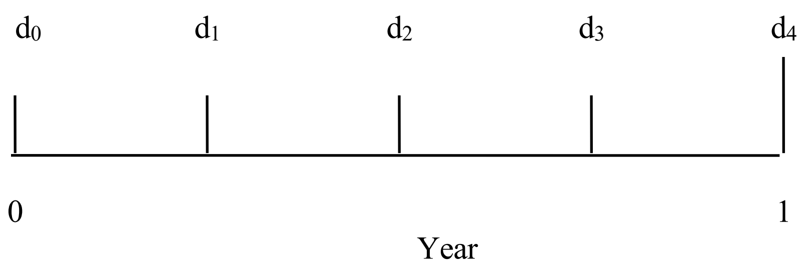
<u>Case 3</u>



$d_1 = d_2 = d_0$

$d_3 = d_4 = d_0(1+g)$

<u>Case 4</u>



$d_1 = d_2 = d_3 = d_0$

$d_4 = d_0(1+g)$

If we assume that the investor invests the quarterly dividend in an alternative investment of the same risk, then the amount accumulated by the end of the year will in all cases be given by:

$$D_1^* = d_1\,(1+k)^{3/4} + d_2\,(1+k)^{1/2} + d_3\,(1+k)^{1/4} + d_4$$

where d_1, d_2, d_3 and d_4 are the four quarterly dividends. Under these new assumptions, the firm's stock price may be expressed by an Annual DCF Model of the form (2), with the exception that:

$$D_1^* = d_1\,(1+k)^{3/4} + d_2\,(1+k)^{1/2} + d_3\,(1+k)^{1/4} + d_4 \qquad \textbf{(9)}$$

is used in place of $D_0(1+g)$. But, we already know that the Annual DCF Model may be reduced to:

$$P_0 = \frac{D_0(1+g)}{k-g}$$

Thus, under the assumptions of the second Quarterly DCF Model, the firm's cost of equity is given by:

$$k = \frac{D_1^*}{P_0} + g \qquad \textbf{(10)}$$

with D_1^* given by (9).

Although equation (10) looks like the Annual DCF Model, there are at least two very important practical differences. First, since D_1^* is always greater than $D_0(1+g)$, the estimates of the cost of equity are always larger (and more accurate) in the Quarterly Model (10) than in the Annual Model. Second, since D_1^* depends on k through equation (9), the unknown "k" appears on both sides of (10), and an iterative procedure is required to solve for k.

APPENDIX 3
ADJUSTING FOR FLOTATION COSTS IN DETERMINING
A PUBLIC UTILITY'S ALLOWED RATE OF RETURN ON EQUITY

I. Introduction

Regulation of public utilities is guided by the principle that utility revenues should be sufficient to allow recovery of all prudently incurred expenses, including the cost of capital. As set forth in the 1944 *Hope Natural Gas* Case [*Federal Power Comm'n v. Hope Natural Gas Co*. 320 U. S. 591 (1944) at 603], the U. S. Supreme Court states:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock....By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.

Since the flotation costs arising from the issuance of debt and equity securities are an integral component of capital costs, this standard requires that the company's revenues be sufficient to fully recover flotation costs.

Despite the widespread agreement that flotation costs should be recovered in the regulatory process, several issues still need to be resolved. These include:

1. How is the term "flotation costs" defined? Does it include only the out-of-pocket costs associated with issuing securities (e. g., legal fees, printing costs, selling and underwriting expenses), or does it also include the reduction in a security's price that frequently accompanies flotation?
2. What should be the time pattern of cost recovery? Should a company be allowed to recover flotation costs immediately, or should flotation costs be recovered over the life of the issue?
3. For the purposes of regulatory accounting, should flotation costs be included as an expense? As an addition to rate base? Or as an additional element of a firm's allowed rate of return?
4. Do existing regulatory methods for flotation cost recovery allow a firm ***full*** recovery of flotation costs?

In this paper, I review the literature pertaining to the above issues and discuss my own views regarding how this literature applies to the cost of equity for a regulated firm.

I. Definition of Flotation Cost

The value of a firm is related to the future stream of net cash flows (revenues minus expenses measured on a cash basis) that can be derived from its assets. In the process of acquiring assets, a firm incurs certain expenses which reduce its value. Some of these expenses or costs are directly associated with revenue production in one period (e. g., wages, cost of goods sold), others are more properly associated with revenue production in many periods (e. g., the acquisition cost of plant and equipment). In either case, the word "cost" refers to any item that reduces the value of a firm.

If this concept is applied to the act of issuing new securities to finance asset purchases, many items are properly included in issuance or flotation costs. These include: (1) compensation received by investment bankers for underwriting services, (2) legal fees, (3) accounting fees, (4) engineering fees, (5) trustee's fees, (6) listing fees, (7) printing and engraving expenses, (8) SEC registration fees, (9) Federal Revenue Stamps, (10) state taxes, (11) warrants granted to underwriters as extra compensation, (12) postage expenses, (13) employees' time, (14) market pressure, and (15) the offer discount. The finance literature generally divides these flotation cost items into three categories, namely, underwriting expenses, issuer expenses, and price effects.

II. Magnitude of Flotation Costs

The finance literature contains several studies of the magnitude of the flotation costs associated with new debt and equity issues. These studies differ primarily with regard to the time period studied, the sample of companies included, and the source of data. The flotation cost studies generally agree, however, that for large issues, underwriting expenses represent approximately one and one-half percent of the proceeds of debt issues and three to five percent of the proceeds of seasoned equity issues. They also agree that issuer expenses represent approximately 0.5 percent of both debt and equity issues, and that the announcement of an equity issue reduces the company's stock price by at least two to three percent of the proceeds from the stock issue. Thus, total flotation costs represent approximately two percent[1] of the proceeds from debt issues, and five and one-half to eight and one-half percent of the proceeds of equity issues.

Lee *et. al.* [14] is an excellent example of the type of flotation cost studies found in the finance literature. The Lee study is a comprehensive recent study of the underwriting and issuer costs associated with debt and equity issues for both utilities and non-utilities. The results of the Lee *et. al.* study are reproduced in Tables 1 and 2. Table 1 demonstrates that the total underwriting and issuer expenses for the 1,092 debt issues in their study averaged 2.24 percent of the proceeds of the issues, while the total underwriting and issuer costs for the 1,593 seasoned equity issues in their study averaged 7.11 percent of the proceeds of the new issue. Table 1 also demonstrates that the total underwriting and issuer costs of seasoned equity offerings, as a percent of proceeds,

[1] The two percent flotation cost on debt only recognizes the cost of newly-issued debt. When interest rates decline, many companies exercise the call provisions on higher cost debt and reissue debt at lower rates. This process involves reacquisition costs that are not included in the academic studies. If reacquisition costs were included in the academic studies, debt flotation costs could increase significantly.

decline with the size of the issue. For issues above $60 million, total underwriting and issuer costs amount to from three to five percent of the amount of the proceeds.

Table 2 reports the total underwriting and issuer expenses for 135 utility debt issues and 136 seasoned utility equity issues. Total underwriting and issuer expenses for utility bond offerings averaged 1.47 percent of the amount of the proceeds and for seasoned utility equity offerings averaged 4.92 percent of the amount of the proceeds. Again, there are some economies of scale associated with larger equity offerings. Total underwriting and issuer expenses for equity offerings in excess of 40 million dollars generally range from three to four percent of the proceeds.

The results of the Lee study for large equity issues are consistent with results of earlier studies by Bhagat and Frost [4], Mikkelson and Partch [17], and Smith [24]. Bhagat and Frost found that total underwriting and issuer expenses average approximately four and one-half percent of the amount of proceeds from negotiated utility offerings during the period 1973 to 1980, and approximately three and one-half percent of the amount of the proceeds from competitive utility offerings over the same period. Mikkelson and Partch found that total underwriting and issuer expenses average five and one-half percent of the proceeds from seasoned equity offerings over the 1972 to 1982 period. Smith found that total underwriting and issuer expenses for larger equity issues generally amount to four to five percent of the proceeds of the new issue.

The finance literature also contains numerous studies of the decline in price associated with sales of large blocks of stock to the public. These articles relate to the price impact of: (1) initial public offerings; (2) the sale of large blocks of stock from one investor to another; and (3) the issuance of seasoned equity issues to the general public. All of these studies generally support the notion that the announcement of the sale of large blocks of stock produces a decline in a company's share price. The decline in share price for initial public offerings is significantly larger than the decline in share price for seasoned equity offerings; and the decline in share price for public utilities is less than the decline in share price for non-public utilities. A comprehensive study of the magnitude of the decline in share price associated specifically with the sale of new equity by public utilities is reported in Pettway [19], who found the market pressure effect for a sample of 368 public utility equity sales to be in the range of two to three percent. This decline in price is a real cost to the utility, because the proceeds to the utility depend on the stock price on the day of issue.

In addition to the price decline associated with the announcement of a new equity issue, the finance literature recognizes that there is also a price decline associated with the actual issuance of equity securities. In particular, underwriters typically sell seasoned new equity securities to investors at a price lower than the closing market price on the day preceding the issue. The Rules of Fair Practice of the National Association of Securities Dealers require that underwriters not sell shares at a price above the offer price. Since the offer price represents a binding constraint to the underwriter, the underwriter tends to set the offer price slightly below the market price on the day of issue to compensate for the risk that the price received by the underwriter may go down, but can not increase. Smith provides evidence that the offer discount tends to be between 0.5 and 0.8 percent of the proceeds of an equity issue. I am not aware of any similar studies for debt issues.

In summary, the finance literature provides strong support for the conclusion that total underwriting and issuer expenses for public utility debt offerings represent approximately two percent of the amount of the proceeds, while total underwriting and issuer expenses for public utility equity offerings represent at least four to five percent of the amount of the proceeds. In addition, the finance literature supports the conclusion that the cost associated with the decline in stock price at the announcement date represents approximately two to three percent as a result of a large public utility equity issue.

III. Time Pattern Of Flotation Cost Recovery

Although flotation costs are incurred only at the time a firm issues new securities, there is no reason why an issuing firm ought to recognize the expense only in the current period. In fact, if assets purchased with the proceeds of a security issue produce revenues over many years, a sound argument can be made in favor of recognizing flotation expenses over a reasonably lengthy period of time. Such recognition is certainly consistent with the generally accepted accounting principle that the time pattern of expenses match the time pattern of revenues, and it is also consistent with the normal treatment of debt flotation expenses in both regulated and unregulated industries.

In the context of a regulated firm, it should be noted that there are many possible time patterns for the recovery of flotation expenses. However, if it is felt that flotation expenses are most appropriately recovered over a period of years, then it should be recognized that investors must also be compensated for the passage of time. That is to say, the value of an investor's capital will be reduced if the expenses are merely distributed over time, without any allowance for the time value of money.

IV. Accounting For Flotation Cost In A Regulatory Setting

In a regulatory setting, a firm's revenue requirements are determined by the equation:

Revenue Requirement = Total Expenses + Allowed Rate of Return x Rate Base

Thus, there are three ways in which an issuing firm can account for and recover its flotation expenses: (1) treat flotation expenses as a current expense and recover them immediately; (2) include flotation expenses in rate base and recover them over time; and (3) adjust the allowed rate of return upward and again recover flotation expenses over time. Before considering methods currently being used to recover flotation expenses in a regulatory setting, I shall briefly consider the advantages and disadvantages of these three basic recovery methods.

Expenses. Treating flotation costs as a current expense has several advantages. Because it allows for recovery at the time the expense occurs, it is not necessary to compute amortized balances over time and to debate which interest rate should be applied to these balances. A firm's stockholders are treated fairly, and so are the firm's customers, because they pay neither more nor less than the actual flotation expense. Since flotation costs are relatively small compared to the total revenue requirement, treatment as a current expense does not cause unusual rate hikes in the year of flotation, as would the introduction of a large generating plant in a state that does not allow Construction Work in Progress in rate base.

On the other hand, there are two major disadvantages of treating flotation costs as a current expense. First, since the asset purchased with the acquired funds will likely generate revenues for many years into the future, it seems unfair that current ratepayers should bear the full cost of issuing new securities, when future ratepayers share in the benefits. Second, this method requires an estimate of the underpricing effect on each security issue. Given the difficulties involved in measuring the extent of underpricing, it may be more accurate to estimate the average underpricing allowance for many securities than to estimate the exact figure for one security.

Rate Base. In an article in *Public Utilities Fortnightly*, Bierman and Hass [5] recommend that flotation costs be treated as an intangible asset that is included in a firm's rate base along with the assets acquired with the stock proceeds. This approach has many advantages. For ratepayers, it provides a better match between benefits and expenses: the future ratepayers who benefit from the financing costs contribute the revenues to recover these costs. For investors, if the allowed rate of return is equal to the investors' required rate of return, it is also theoretically fair since they are compensated for the opportunity cost of their investment (including both the time value of money and the investment risk).

Despite the compelling advantages of this method of cost recovery, there are several disadvantages that probably explain why it has not been used in practice. First, a firm will only recover the proper amount for flotation expenses if the rate base is multiplied by the appropriate cost of capital. To the extent that a commission underestimates or overestimates the cost of capital, a firm will under-recover or over-recover its flotation expenses. Second, it may be both legally and psychologically difficult for commissioners to include an intangible asset in a firm's rate base. According to established legal doctrine, assets are to be included in rate base only if they are "used and useful" in the public service. It is unclear whether intangible assets such as flotation expenses meet this criterion.

Rate of Return. The prevailing practice among state regulators is to treat flotation expenses as an additional element of a firm's cost of capital or allowed rate of return. This method is similar to the second method above (treatment in rate base) in that some part of the initial flotation cost is amortized over time. However, it has a disadvantage not shared by the rate base method. If flotation cost is included in rate base, it is fairly easy to keep track of the flotation cost on each new equity issue and see how it is recovered over time. Using the rate of return method, it is not possible to track the flotation cost for specific issues because the flotation cost for a specific issue is never recorded. Thus, it is not clear to participants whether a current allowance is meant to recover (1) flotation costs actually incurred in a test period, (2) expected future flotation costs, or (3) past flotation costs. This confusion never arises in the treatment of debt flotation costs. Because the exact costs are recorded and explicitly amortized over time, participants recognize that current allowances for debt flotation costs are meant to recover some fraction of the flotation costs on all past debt issues.

V. Existing Regulatory Methods

Although most state commissions prefer to let a regulated firm recover flotation expenses through an adjustment to the allowed rate of return, there is considerable controversy about the magnitude of the required adjustment. The following are some of the most frequently asked questions: (1) Should an adjustment to the allowed return be made every year, or should the adjustment be made only in those years in which new equity is raised? (2) Should an adjusted rate of return be applied to the entire rate base, or should it be applied only to that portion of the rate base financed with paid-in capital (as opposed to retained earnings)? (3) What is the appropriate formula for adjusting the rate of return?

This section reviews several methods of allowing for flotation cost recovery. Because the regulatory methods of allowing for recovery of debt flotation costs are well known and widely accepted, I will begin my discussion of flotation cost recovery procedures by describing the widely-accepted procedure of allowing for debt flotation cost recovery.

Debt Flotation Costs

Regulators uniformly recognize that companies incur flotation costs when they issue debt securities. They typically allow recovery of debt flotation costs by making an adjustment to both the cost of debt and the rate base (see Brigham [6]). Assume that: (1) a regulated company issues \$100 million in bonds that mature in 10 years; (2) the interest rate on these bonds is seven percent; and (3) flotation costs represent four percent of the amount of the proceeds. Then the cost of debt for regulatory purposes will generally be calculated as follows:

$$
\begin{aligned}
\text{Cost of Debt} &= \frac{\text{Interest expense} + \text{Amortization of flotation costs}}{\text{Principal value - Unamortized flotation costs}} \\
&= \frac{\$7{,}000{,}000 + \$400{,}000}{\$100{,}000{,}000 - \$4{,}000{,}000} \\
&= 7.71\%
\end{aligned}
$$

Thus, current regulatory practice requires that the cost of debt be adjusted upward by approximately 71 basis points, in this example, to allow for the recovery of debt flotation costs. This example does not include losses on reacquisition of debt. The flotation cost allowance would increase if losses on reacquisition of debt were included.

The logic behind the traditional method of allowing for recovery of debt flotation costs is simple. Although the company has issued \$100 million in bonds, it can only invest \$96 million in rate base because flotation costs have reduced the amount of funds received by \$4 million. If the company is not allowed to earn a 71 basis point higher rate of return on the \$96 million invested in rate base, it will not generate sufficient cash flow to pay the seven percent interest on the \$100 million in bonds it has issued. Thus, proper regulatory treatment is to increase the required rate of return on debt by 71 basis points.

Equity Flotation Costs

The finance literature discusses several methods of recovering equity flotation costs. Because each method stems from a specific model, (*i.e.*, set of assumptions) of a firm and its cash flows, I will highlight the assumptions that distinguish one method from another.

Arzac and Marcus. Arzac and Marcus [2] study the proper flotation cost adjustment formula for a firm that makes continuous use of retained earnings and external equity financing and maintains a constant capital structure (debt/equity ratio). They assume at the outset that underwriting expenses and underpricing apply only to new equity obtained from external sources. They also assume that a firm has previously recovered all underwriting expenses, issuer expenses, and underpricing associated with previous issues of new equity.

To discuss and compare various equity flotation cost adjustment formulas, Arzac and Marcus make use of the following notation:

k	=	an investors' required return on equity
r	=	a utility's allowed return on equity base
S	=	value of equity in the absence of flotation costs
S_f	=	value of equity net of flotation costs
K_t	=	equity base at time t
E_t	=	total earnings in year t
D_t	=	total cash dividends at time t
b	=	$(E_t\text{-}D_t) \div E_t$ = retention rate, expressed as a fraction of earnings
h	=	new equity issues, expressed as a fraction of earnings
m	=	equity investment rate, expressed as a fraction of earnings, $m = b + h < 1$
f	=	flotation costs, expressed as a fraction of the value of an issue.

Because of flotation costs, Arzac and Marcus assume that a firm must issue a greater amount of external equity each year than it actually needs. In terms of the above notation, a firm issues $hE_t \div (1\text{-}f)$ to obtain hE_t in external equity funding. Thus, each year a firm loses:

Equation 1

$$L = \frac{hE_t}{1-f} - hE_t = \frac{f}{1-f} \times hE_t$$

due to flotation expenses. The present value, V, of all future flotation expenses is:

Equation 2

$$V = \sum_{t=1}^{\infty} \frac{fhE_t}{(1-f)(1+k)^t} = \frac{fh}{1-f} \times \frac{rK_0}{k-mr}$$

To avoid diluting the value of the initial stockholder's equity, a regulatory authority needs to find the value of r, a firm's allowed return on equity base, that equates the value of equity net of flotation costs to the initial equity base ($S_f = K_0$). Since the value of equity net of flotation costs equals the value of equity in the absence of flotation costs minus the present value of flotation costs, a regulatory authority needs to find that value of *r* that solves the following equation:

$$S_f = S - L.$$

This value is:

Equation 3

$$r = \frac{k}{1 - \frac{fh}{1-f}}$$

To illustrate the Arzac-Marcus approach to adjusting the allowed return on equity for the effect of flotation costs, suppose that the cost of equity in the absence of flotation costs is 12 percent. Furthermore, assume that a firm obtains external equity financing each year equal to 10 percent of its earnings and that flotation expenses equal 5 percent of the value of each issue. Then, according to Arzac and Marcus, the allowed return on equity should be:

$$r = \frac{.12}{1 - \frac{(.05).(.1)}{.95}} = .1206 = 12.06\%$$

<u>Summary</u>. With respect to the three questions raised at the beginning of this section, it is evident that Arzac and Marcus believe the flotation cost adjustment should be applied each year, since continuous external equity financing is a fundamental assumption of their model. They also believe that the adjusted rate of return should be applied to the entire equity-financed portion of the rate base because their model is based on the assumption that the flotation cost adjustment mechanism will be applied to the entire equity-financed portion of the rate base. Finally, Arzac and Marcus recommend a flotation cost adjustment formula, Equation (3), that implicitly excludes recovery of financing costs associated with financing in previous periods and includes only an allowance for the fraction of equity financing obtained from external sources.

<u>Patterson</u>. The Arzac-Marcus flotation cost adjustment formula is significantly different from the conventional approach (found in many introductory textbooks) which recommends the adjustment equation:

Equation 4

$$r = \frac{D_t}{P_{t-1}(1-f)} + g$$

where P_{t-1} is the stock price in the previous period and g is the expected dividend growth rate. Patterson [18] compares the Arzac-Marcus adjustment formula to the conventional approach and reaches the conclusion that the Arzac-Marcus formula effectively expenses issuance costs as they are incurred, while the conventional approach effectively amortizes them over an assumed infinite life of the equity issue. Thus, the conventional formula is similar to the formula for the recovery of debt flotation costs: it is not meant to compensate investors for the flotation costs of future issues, but instead is meant to compensate investors for the flotation costs of previous issues. Patterson argues that the conventional approach is more appropriate for rate making purposes because the plant purchased with external equity funds will yield benefits over many future periods.

Illustration. To illustrate the Patterson approach to flotation cost recovery, assume that a newly organized utility sells an initial issue of stock for $100 per share, and that the utility plans to finance all new investments with retained earnings. Assume also that: (1) the initial dividend per share is six dollars; (2) the expected long-run dividend growth rate is six percent; (3) the flotation cost is five percent of the amount of the proceeds; and (4) the payout ratio is 51.28 percent. Then, the investor's required rate of return on equity is [k = (D/P) + g = 6 percent + 6 percent = 12 percent]; and the flotation-cost-adjusted cost of equity is [6 percent (1/.95) + 6 percent = 12.316 percent].

The effects of the Patterson adjustment formula on the utility's rate base, dividends, earnings, and stock price are shown in Table 3. We see that the Patterson formula allows earnings and dividends to grow at the expected six percent rate. We also see that the present value of expected future dividends, $100, is just sufficient to induce investors to part with their money. If the present value of expected future dividends were less than $100, investors would not have been willing to invest $100 in the firm. Furthermore, the present value of future dividends will only equal $100 if the firm is allowed to earn the 12.316 percent flotation-cost-adjusted cost of equity on its entire rate base.

Summary. Patterson's opinions on the three issues raised in this section are in stark contrast to those of Arzac and Marcus. He believes that: (1) a flotation cost adjustment should be applied in every year, regardless of whether a firm issues any new equity in each year; (2) a flotation cost adjustment should be applied to the entire equity-financed portion of the rate base, including that portion financed by retained earnings; and (3) the rate of return adjustment formula should allow a firm to recover an appropriate fraction of all previous flotation expenses.

VI. Conclusion

Having reviewed the literature and analyzed flotation cost issues, I conclude that:

Definition of Flotation Cost: A regulated firm should be allowed to recover both the total underwriting and issuance expenses associated with issuing securities and the cost of market pressure.

Time Pattern of Flotation Cost Recovery. Shareholders are indifferent between the alternatives of immediate recovery of flotation costs and recovery over time, as long as they are fairly compensated for the opportunity cost of their money. This opportunity cost must include both the time value of money and a risk premium for equity investments of this nature.

Regulatory Recovery of Flotation Costs. The Patterson approach to recovering flotation costs is the only rate-of-return-adjustment approach that meets the *Hope* case criterion that a regulated company's revenues must be sufficient to allow the company an opportunity to recover all prudently incurred expenses, including the cost of capital. The Patterson approach is also the only rate-of-return-adjustment approach that provides an incentive for investors to invest in the regulated company.

Implementation of a Flotation Cost Adjustment. As noted earlier, prevailing regulatory practice seems to be to allow the recovery of flotation costs through an adjustment to the required rate of return. My review of the literature on this subject indicates that there are at least two recommended methods of making this adjustment: the Patterson approach and the Arzac-Marcus approach. The Patterson approach assumes that a firm's flotation expenses on new equity issues are treated in the same manner as flotation expenses on new bond issues, *i.e.*, they are amortized over future time periods. If this assumption is true (and I believe it is), then the flotation cost adjustment should be applied to a firm's entire equity base, including retained earnings. In practical terms, the Patterson approach produces an increase in a firm's cost of equity of approximately thirty basis points. The Arzac-Marcus approach assumes that flotation costs on new equity issues are recovered entirely in the year in which the securities are sold. Under the Arzac-Marcus assumption, a firm should not be allowed any adjustments for flotation costs associated with previous flotations. Instead, a firm should be allowed only an adjustment on future security sales as they occur. Under reasonable assumptions about the rate of new equity sales, this method produces an increase in the cost of equity of approximately six basis points. Since the Arzac-Marcus approach does not allow the company to recover the entire amount of its flotation cost, I recommend that this approach be rejected and the Patterson approach be accepted.

BIBLIOGRAPHY

1. Armknecht, Raymond, Fred Grygiel and Patrick Hess, "Market Pressure: The Sales of New Common Equity and Rate of Return Regulation, "Proceedings of the Business and Economic Statistics Section of the American Statistical Association, 1974, pp. 80—91.
2. Arzac, E. R., and M. Marcus, "Flotation Cost Allowance in Rate of Return Regulation: A Note," *Journal of Finance*, December 1981, pp. 1199—1202.
3. Barclay, M. J. and R. H. Litzenberger, 1988, "Announcement Effects of New Equity Issues and the Use of Intraday Price Data," *Journal of Financial Economics* 21, 71—99.
4. Bhagat, S. and P. A. Frost, 1986, "Issuing Costs to Existing Shareholders in Competitive and Negotiated Underwritten Public Utility Equity Offerings," *Journal of Financial Economics* 15, 233—59.
5. Bierman, H., and J. E. Hass, "Equity Flotation Cost Adjustments in Utilities' Cost of Service," *Public Utilities Fortnightly*, March 1, 1983, pp.46—49 .
6. Bowyer, Jr., John W., and Jess B. Yawitz, "The Effect of New Equity Issues on Utility Stock Prices," *Pubic Utilities Fortnightly*, May 22, 1980.
7. Brigham, Eugene F., Dana Aberwald, and Louis C. Gapenski, "Common Equity Flotation Costs and Rate Making," *Public Utilities Fortnightly*, May 2, 1985, pp. 28—26.
8. Calomiris, C. W. and D. M. G Raff, 1995, "The Evolution of Market Structure, Information, and Spreads in American Investment Banking," in M. B. Bordo and R. Sylla, eds., *Anglo-American Finance: Financial Markets and Institutions in 20th Century North America and the U. K.* (Business One-Irwin Homewood, IL), 103—60.
9. Dunbar, C. G., 1995, "The Use of Warrants as Underwriter Compensation in Initial Public Offerings," *Journal of Financial Economics* 38, 59—78.
10. Evans, Robert E., "On the Existence, Measurement, and Economic Significance of Market Pressure in the Pricing of New Equity Shares," unpublished dissertation, University of Wisconsin, 1978.
11. Howe, K. M., "Flotation Cost Allowance in Rate of Return Regulation: Comment," *Journal of Finance*, March 1984, pp. 289—290.
12. Howe, K. M., "Flotation Cost Allowance for the Regulated Firm: A Comparison of Alternatives," unpublished working paper, School of Business, Iowa State University.
13. Ibbotson, R. C., "Price Performance of Common Stock New Issues," *Journal of Financial Economics*, 1975, pp. 235—272.
14. Lee, Inmoo, Scott Lochhead, Jay Ritter, and Quanshui Zhao, "The Costs of Raising Capital," *The Journal of Financial Research*, Vol XIX No 1 (Spring 1996), 59—74
15. Logue, D. E., "On the Pricing of Unseasoned Equity Offerings: 1965—1969," *Journal of Financial and Quantitative Analysis*, January 1973, pp. 91—103.
16. McDonald, J. G. and A. K. Fisher, "New Issue Stock Price Behavior," *Journal of Finance*, March 1972, pp. 97—102.
17. Mikkelson, Wayne H. and M. Megan Partch, "Valuation Effects of Security Offerings and the Issuance Process," *Journal of Financial Economics* 15 (1986), pp. 31-60.
18. Patterson, C. S., "Flotation Cost Allowance in Rate of Return Regulation: Comment," *Journal of Finance*, September 1983, pp. 1335—1338.
19. Pettway, R. H., "The Effects of New Equity Sales Upon Utility Share Prices," *Public Utilities Fortnightly*, May 10, 1984, pp. 35—39.
20. Reilly, F. K. and K. Hatfield, "Investor Experience with New Stock Issues," *Financial Analysts' Journal*, September--October 1969, pp. 73—80.

21. Richter, P. H., "The Ever Present Need for an Underpricing Allowance," *Public Utilities Fortnightly*, February 18, 1982, pp. 58—61.

22. Scholes, M., "The Market for New Securities: Substitution versus Price Pressure and the Effects of Information on Share Prices," *Journal of Business*, April 1972, pp. 179—211.

23. Securities and Exchange Commission, Report of Special Study on Securities Markets, U. S. Government Printing Office, Washington, D. C. 1963.

24. Smith, Clifford W. Jr., "Alternative Methods for Raising Capital," *Journal of Financial Economics* 5 (1977) 273-307.

Table 1

Direct Costs as a Percentage of Gross Proceeds
for Equity (IPOs and SEOs) and Straight and Convertible Bonds
Offered by Domestic Operating Companies 1990—1994[2]

Equities

		IPOs				SEOs			
Line No.	Proceeds ($ in millions)	No. of Issues	Gross Spreads	Other Direct Expenses	Total Direct Costs	No. of Issues	Gross Spreads	Other Direct Expenses	Total Direct Costs
1	2-9.99	337	9.05%	7.91%	16.96%	167	7.72%	5.56%	13.28%
2	10-19.99	389	7.24%	4.39%	11.63%	310	6.23%	2.49%	8.72%
3	20-39.99	533	7.01%	2.69%	9.70%	425	5.60%	1.33%	6.93%
4	40-59.99	215	6.96%	1.76%	8.72%	261	5.05%	0.82%	5.87%
5	60-79.99	79	6.74%	1.46%	8.20%	143	4.57%	0.61%	5.18%
6	80-99.99	51	6.47%	1.44%	7.91%	71	4.25%	0.48%	4.73%
7	100-199.99	106	6.03%	1.03%	7.06%	152	3.85%	0.37%	4.22%
8	200-499.99	47	5.67%	0.86%	6.53%	55	3.26%	0.21%	3.47%
9	500 and up	10	5.21%	0.51%	5.72%	9	3.03%	0.12%	3.15%
10	**Total/Average**	**1,767**	**7.31%**	**3.69%**	**11.00%**	**1,593**	**5.44%**	**1.67%**	**7.11%**

Bonds

		Convertible Bonds				Straight Bonds			
Line No.	Proceeds ($ in millions)	No. of Issues	Gross Spreads	Other Direct Expenses	Total Direct Costs	No. of Issues	Gross Spreads	Other Direct Expenses	Total Direct Costs
1	2-9.99	4	6.07%	2.68%	8.75%	32	2.07%	2.32%	4.39%
2	10-19.99	14	5.48%	3.18%	8.66%	78	1.36%	1.40%	2.76%
3	20-39.99	18	4.16%	1.95%	6.11%	89	1.54%	0.88%	2.42%
4	40-59.99	28	3.26%	1.04%	4.30%	90	0.72%	0.60%	1.32%
5	60-79.99	47	2.64%	0.59%	3.23%	92	1.76%	0.58%	2.34%
6	80-99.99	13	2.43%	0.61%	3.04%	112	1.55%	0.61%	2.16%
7	100-199.99	57	2.34%	0.42%	2.76%	409	1.77%	0.54%	2.31%
8	200-499.99	27	1.99%	0.19%	2.18%	170	1.79%	0.40%	2.19%
9	500 and up	3	2.00%	0.09%	2.09%	20	1.39%	0.25%	1.64%
10	**Total/Average**	**211**	**2.92%**	**0.87%**	**3.79%**	**1,092**	**1.62%**	**0.62%**	**2.24%**

[2] Inmoo Lee, Scott Lochhead, Jay Ritter, and Quanshui Zhao, "The Costs of Raising Capital," *Journal of Financial Research* Vol 19 No 1 (Spring 1996) pp. 59-74.

Notes:

Closed-end funds and unit offerings are excluded from the sample. Rights offerings for SEOs are also excluded. Bond offerings do not include securities backed by mortgages and issues by Federal agencies. Only firm commitment offerings and non-shelf-registered offerings are included.
Gross Spreads as a percentage of total proceeds, including management fee, underwriting fee, and selling concession.
Other Direct Expenses as a percentage of total proceeds, including management fee, underwriting fee, and selling concession.
Total Direct Costs as a percentage of total proceeds (total direct costs are the sum of gross spreads and other direct expenses).

Table 2
Direct Costs of Raising Capital 1990—1994
Utility versus Non-Utility Companies[3]

Equities

	Non-Utilities	IPOs			SEOs		
Line No.	Proceeds ($ in millions)	No. of Issues	Gross Spreads	Total Direct Costs	No. Of Issues	Gross Spreads	Total Direct Costs
1	2-9.99	332	9.04%	16.97%	154	7.91%	13.76%
2	10-19.99	388	7.24%	11.64%	278	6.42%	9.01%
3	20-39.99	528	7.01%	9.70%	399	5.70%	7.07%
4	40-59.99	214	6.96%	8.71%	240	5.17%	6.02%
5	60-79.99	78	6.74%	8.21%	131	4.68%	5.31%
6	80-99.99	47	6.46%	7.88%	60	4.35%	4.84%
7	100-199.99	101	6.01%	7.01%	137	3.97%	4.36%
8	200-499.99	44	5.65%	6.49%	50	3.27%	3.48%
9	500 and up	10	5.21%	5.72%	8	3.12%	3.25%
10	**Total/Average**	1,742	7.31%	11.01%	1,457	5.57%	7.32%
11	**Utilities Only**						
12	2-9.99	5	9.40%	16.54%	13	5.41%	7.68%
13	10-19.99	1	7.00%	8.77%	32	4.59%	6.21%
14	20-39.99	5	7.00%	9.86%	26	4.17%	4.96%
15	40-59.99	1	6.98%	11.55%	21	3.69%	4.12%
16	60-79.99	1	6.50%	7.55%	12	3.39%	3.72%
17	80-99.99	4	6.57%	8.24%	11	3.68%	4.11%
18	100-199.99	5	6.45%	7.96%	15	2.83%	2.98%
19	200-499.99	3	5.88%	7.00%	5	3.19%	3.48%
20	500 and up	0			1	2.25%	2.31%
21	**Total/Average**	25	7.15%	10.14%	136	4.01%	4.92%

[3] Lee *et al, op. cit.*

Table 2 (continued)
Direct Costs of Raising Capital 1990—1994
Utility versus Non-Utility Companies[4]

Bonds

	Non- Utilities	Convertible Bonds			Straight Bonds		
Line No.	Proceeds ($ in millions)	No. of Issues	Gross Spreads	Total Direct Costs	No. of Issues	Gross Spreads	Total Direct Costs
1	2-9.99	4	6.07%	8.75%	29	2.07%	4.53%
2	10-19.99	12	5.54%	8.65%	47	1.70%	3.28%
3	20-39.99	16	4.20%	6.23%	63	1.59%	2.52%
4	40-59.99	28	3.26%	4.30%	76	0.73%	1.37%
5	60-79.99	47	2.64%	3.23%	84	1.84%	2.44%
6	80-99.99	12	2.54%	3.19%	104	1.61%	2.25%
7	100-199.99	55	2.34%	2.77%	381	1.83%	2.38%
8	200-499.99	26	1.97%	2.16%	154	1.87%	2.27%
9	500 and up	3	2.00%	2.09%	19	1.28%	1.53%
10	**Total/Average**	203	2.90%	3.75%	957	1.70%	2.34%
11	**Utilities Only**						
12	2-9.99	0			3	2.00%	3.28%
13	10-19.99	2	5.13%	8.72%	31	0.86%	1.35%
14	20-39.99	2	3.88%	5.18%	26	1.40%	2.06%
15	40-59.99	0			14	0.63%	1.10%
16	60-79.99	0			8	0.87%	1.13%
17	80-99.99	1	1.13%	1.34%	8	0.71%	0.98%
18	100-199.99	2	2.50%	2.74%	28	1.06%	1.42%
19	200-499.99	1	2.50%	2.65%	16	1.00%	1.40%
20	500 and up	0			1	3.50%	na[5]
21	**Total/Average**	8	3.33%	4.66%	135	1.04%	1.47%

Notes:
Total proceeds raised in the United States, excluding proceeds from the exercise of over allotment options.
Gross spreads as a percentage of total proceeds (including management fee, underwriting fee, and selling concession).
Other direct expenses as a percentage of total proceeds (including registration fee and printing, legal, and auditing costs).

[4] Lee *et al, op. cit.*

[5] Not available because of missing data on other direct expenses.

Table 3
Illustration of Patterson Approach to Flotation Cost Recovery

LINE NO.	TIME PERIOD	RATE BASE	EARNINGS @ 12.32%	EARNINGS @ 12.00%	DIVIDENDS	AMORTIZATION INITIAL FC
1	0	95.00				
2	1	100.70	11.70	11.40	6.00	0.3000
3	2	106.74	12.40	12.08	6.36	0.3180
4	3	113.15	13.15	12.81	6.74	0.3371
5	4	119.94	13.93	13.58	7.15	0.3573
6	5	127.13	14.77	14.39	7.57	0.3787
7	6	134.76	15.66	15.26	8.03	0.4015
8	7	142.84	16.60	16.17	8.51	0.4256
9	8	151.42	17.59	17.14	9.02	0.4511
10	9	160.50	18.65	18.17	9.56	0.4782
11	10	170.13	19.77	19.26	10.14	0.5068
12	11	180.34	20.95	20.42	10.75	0.5373
13	12	191.16	22.21	21.64	11.39	0.5695
14	13	202.63	23.54	22.94	12.07	0.6037
15	14	214.79	24.96	24.32	12.80	0.6399
16	15	227.67	26.45	25.77	13.57	0.6783
17	16	241.33	28.04	27.32	14.38	0.7190
18	17	255.81	29.72	28.96	15.24	0.7621
19	18	271.16	31.51	30.70	16.16	0.8078
20	19	287.43	33.40	32.54	17.13	0.8563
21	20	304.68	35.40	34.49	18.15	0.9077
22	21	322.96	37.52	36.56	19.24	0.9621
23	22	342.34	39.77	38.76	20.40	1.0199
24	23	362.88	42.16	41.08	21.62	1.0811
25	24	384.65	44.69	43.55	22.92	1.1459
26	25	407.73	47.37	46.16	24.29	1.2147
27	26	432.19	50.21	48.93	25.75	1.2876
28	27	458.12	53.23	51.86	27.30	1.3648
29	28	485.61	56.42	54.97	28.93	1.4467
30	29	514.75	59.81	58.27	30.67	1.5335
31	30	545.63	63.40	61.77	32.51	1.6255
32	Present Value@12%		195.00	190.00	100.00	5.00

APPENDIX 4
***EX ANTE* RISK PREMIUM APPROACH**

My ex ante risk premium method is based on studies of the DCF expected return on proxy companies compared to the interest rate on Moody's A-rated utility bonds. Specifically, for each month in my study period, I calculate the risk premium using the equation,

$$RP_{PROXY} = DCF_{PROXY} - I_A$$

where:

RP_{PROXY}	=	the required risk premium on an equity investment in the proxy group of companies,
DCF_{PROXY}	=	average DCF estimated cost of equity on a portfolio of proxy companies; and
I_A	=	the yield to maturity on an investment in A-rated utility bonds.

Electric Company Ex Ante Risk Premium Analysis. For my ex ante risk premium electric proxy group DCF analysis for the years 1999 through 2015, I begin with the Moody's group of twenty-four electric utilities shown in Table 1. I use the Moody's group of electric utilities because they are a widely followed group of electric utilities, and use of this constant group greatly simplified the data collection task required to estimate the ex ante risk premium over the months of my study. Simplifying the data collection task is desirable because the ex ante risk premium approach requires that the DCF model be estimated for every company in every month of the study period. Because many of the companies that were formerly included in the Moody's electric utility group have been eliminated due to mergers and acquisitions, and because it is desirable to have a larger set of companies in the analysis than are now available in the Moody's group, beginning in January 2016 I use the same proxy group of electric utilities and DCF model in my ex ante risk premium analysis as are used in my discounted cash flow analysis. The Ex Ante Risk Premium exhibit in my direct testimony displays the average DCF estimated cost of equity on an investment in the portfolio of electric utilities and the yield to maturity on A-rated utility bonds in each month of the study.

Previous studies have shown that the ex ante risk premium tends to vary inversely with the level of interest rates, that is, the risk premium tends to increase when interest rates decline, and decrease when interest rates go up. To test whether my studies also indicate that the ex ante risk premium varies inversely with the level of interest rates, I performed a regression analysis of the relationship between the ex ante risk premium and the yield to maturity on A-rated utility bonds, using the equation,

$$RP_{PROXY} = a + (b \times I_A) + e$$

where:

RP_{PROXY} = risk premium on proxy company group;

I_A = yield to maturity on A-rated utility bonds;

e = a random residual; and

a, b = coefficients estimated by the regression procedure.

Regression analysis assumes that the statistical residuals from the regression equation are random. My examination of the residuals revealed that there is a significant probability that the residuals are serially correlated (non-zero serial correlation indicates that the residual in one time period tends to be correlated with the residual in the previous time period). Therefore, I made adjustments to my data to correct for the possibility of serial correlation in the residuals.

The common procedure for dealing with serial correlation in the residuals is to estimate the regression coefficients in two steps. First, a multiple regression analysis is used to estimate the serial correlation coefficient, *r*. Second, the estimated serial correlation coefficient is used to transform the original variables into new variables whose serial correlation is approximately zero. The regression coefficients are then re-estimated using the transformed variables as inputs in the regression equation. Based on my knowledge of the statistical relationship between the yield to maturity on A-rated utility bonds and the required risk premium, my estimate of the ex ante risk premium on an investment in my proxy electric company group as compared to an investment in A-rated utility bonds is given by the equation:

$$RP_{PROXY} = 8.51 - .624 \times I_A.$$

$$= (13.986) \qquad (-6.969)$$ [6]

Using the forecast 5.4 percent yield to maturity on A-rated utility bonds, the regression equation produces an ex ante risk premium based on the electric proxy group equal to 5.14 percent (8.51 – .624 x 5.4 = 5.14).

To estimate the cost of equity using the ex ante risk premium method, one may add the estimated risk premium over the yield on A-rated utility bonds to the yield to maturity on A-rated

[6] The t-statistics are shown in parentheses.

utility bonds. The forecast yield on A-rated utility bonds is 5.4 percent. As noted above, my analyses produce an estimated risk premium over the yield on A-rated utility bonds equal to 5.14 percent. Adding an estimated risk premium of 5.14 percent to the 5.4 percent forecasted yield to maturity on A-rated utility bonds produces a cost of equity estimate of 10.54 percent for the electric company proxy group using the ex ante risk premium method.

APPENDIX 5
***EX POST* RISK PREMIUM APPROACH**

Source

Stock price and yield information is obtained from Standard & Poor's Security Price publication. Standard & Poor's derives the stock dividend yield by dividing the aggregate cash dividends (based on the latest known annual rate) by the aggregate market value of the stocks in the group. The bond price information is obtained by calculating the present value of a bond due in thirty years with a $4.00 coupon and a yield to maturity of a particular year's indicated Moody's A-rated utility bond yield. The values shown in the schedules are the January values of the respective indices.

Calculation of Stock and Bond Returns

Sample calculation of "Stock Return" column:

$$\text{Stock Return (2018)} = \left[\frac{\text{Stock Price (2019) - Stock Price (2018) + Dividend (2018)}}{\text{Stock Price (2018)}} \right]$$

where Dividend (2018) = Stock Price (2018) x Stock Div. Yield (2018)

Sample calculation of "Bond Return" column:

$$\text{Bond Return (2018)} = \left[\frac{\text{Bond Price (2019) - Bond Price (2018) + Interest (2018)}}{\text{Bond Price (2018)}} \right]$$

where Interest = $4.00.

Common Equity to Total Capitalization of Proxy Group Operating Companies
As of December 31, 2018

Company Name	Parent Company Name	2018 Common Equity/ Total Capitalization (%)
Interstate Power and Light Company	Alliant Energy Corporation	51.7%
Wisconsin Power and Light Company	Alliant Energy Corporation	52.7%
Ameren Illinois Company	Ameren Corporation	52.4%
Union Electric Company	Ameren Corporation	52.0%
Appalachian Power Company	American Electric Power Company, Inc.	49.5%
Indiana Michigan Power Company	American Electric Power Company, Inc.	44.6%
Kentucky Power Company	American Electric Power Company, Inc.	45.7%
Kingsport Power Company	American Electric Power Company, Inc.	50.8%
Ohio Power Company	American Electric Power Company, Inc.	57.8%
Public Service Company of Oklahoma	American Electric Power Company, Inc.	49.2%
Southwestern Electric Power Company	American Electric Power Company, Inc.	47.0%
Wheeling Power Company	American Electric Power Company, Inc.	54.6%
Central Maine Power Company	Avangrid, Inc.	63.2%
Black Hills Colorado Electric, Inc.	Black Hills Corporation	53.2%
Black Hills Power, Inc.	Black Hills Corporation	54.1%
Cheyenne Light, Fuel and Power Company	Black Hills Corporation	53.8%
CenterPoint Energy Houston Electric, LLC	CenterPoint Energy, Inc.	44.8%
Southern Indiana Gas and Electric Company	CenterPoint Energy, Inc.	58.5%
Consumers Energy Company	CMS Energy Corporation	50.1%
SCANA Corporation	Dominion Energy, Inc.	45.5%
South Carolina Electric & Gas Company	Dominion Energy, Inc.	44.9%
Virginia Electric and Power Company	Dominion Energy, Inc.	52.6%
DTE Electric Company	DTE Energy Company	51.0%
Duke Energy Carolinas, LLC	Duke Energy Corporation	51.8%
Duke Energy Florida, LLC	Duke Energy Corporation	50.0%
Duke Energy Indiana, LLC	Duke Energy Corporation	53.3%
Duke Energy Kentucky, Inc.	Duke Energy Corporation	51.9%
Duke Energy Ohio, Inc.	Duke Energy Corporation	68.1%
Duke Energy Progress, LLC	Duke Energy Corporation	51.0%
Southern California Edison Company	Edison International	43.0%
El Paso Electric Company	El Paso Electric Company	47.9%
Great Plains Energy Incorporated	Evergy, Inc.	51.1%
Kansas City Power & Light Company	Evergy, Inc.	49.5%
Kansas Gas and Electric Company	Evergy, Inc.	75.0%
KCP&L Greater Missouri Operations Company	Evergy, Inc.	54.7%
Westar Energy (KPL)	Evergy, Inc.	59.1%
Westar Energy, Inc.	Evergy, Inc.	65.2%
Connecticut Light and Power Company	Eversource Energy	55.3%
NSTAR Electric Company	Eversource Energy	55.4%
Public Service Company of New Hampshire	Eversource Energy	47.9%
Atlantic City Electric Company	Exelon Corporation	49.1%
Baltimore Gas and Electric Company	Exelon Corporation	53.7%
Commonwealth Edison Company	Exelon Corporation	55.1%
Delmarva Power & Light Company	Exelon Corporation	50.0%
PECO Energy Company	Exelon Corporation	53.7%
Potomac Electric Power Company	Exelon Corporation	50.0%
Florida Power & Light Company	NextEra Energy, Inc.	64.4%
Gulf Power Company	NextEra Energy, Inc.	59.7%
Otter Tail Power Company	Otter Tail Corporation	53.6%
Arizona Public Service Company	Pinnacle West Capital Corporation	54.4%
Public Service Company of New Mexico	PNM Resources, Inc.	45.5%
Portland General Electric Company	Portland General Electric Company	50.2%
Kentucky Utilities Company	PPL Corporation	54.8%
Louisville Gas and Electric Company	PPL Corporation	55.8%
PPL Electric Utilities Corporation	PPL Corporation	54.5%
Public Service Electric and Gas Company	Public Service Enterprise Group Incorporated	54.2%
Energy Future Holdings Corp	Sempra Energy	59.5%
Oncor Electric Delivery Company LLC	Sempra Energy	59.5%
San Diego Gas & Electric Company	Sempra Energy	55.8%
Alabama Power Company	Southern Company	46.9%
Georgia Power Company	Southern Company	59.0%
Mississippi Power Company	Southern Company	50.3%
Upper Michigan Energy Resources Corporation	WEC Energy Group, Inc.	47.0%
Wisconsin Electric Power Company	WEC Energy Group, Inc.	55.8%
Wisconsin Public Service Corporation	WEC Energy Group, Inc.	57.3%
Northern States Power Company - MN	Xcel Energy Inc.	52.8%
Northern States Power Company - WI	Xcel Energy Inc.	53.6%
Public Service Company of Colorado	Xcel Energy Inc.	56.3%
Southwestern Public Service Company	Xcel Energy Inc.	54.2%
Mean		**53.3%**
Median		**53.2%**

Source: SNL Financial