COZEN O'CONNOR
A Pennsylvania Professional Corporation

March 16, 2023

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VIA E-MAIL (BOARD.SECRETARY@BPU.NJ.GOV)

Acting Secretary Carmen Diaz
NJ Board of Public Utilities
44 South Clinton Street, 9th Floor
P.O. Box 350
Trenton, New Jersey 08625

Re: In the Matter of the Verified Petition of Jersey Central Power & Light Company for Review and Approval of Increases in and Other Adjustments to Its Rates and Charges For Electric Service, and For Approval of Other Proposed Tariff Revisions in Connection Therewith ("2023 Base Rate Filing")
BPU Docket No. _____

Dear Acting Secretary Diaz:

On behalf of the Petitioner, Jersey Central Power & Light Company ("JCP&L"), attached for filing with the Board of Public Utilities ("Board") are copies of JCP&L's Verified Petition and appendices, direct testimony, schedules and exhibits thereto, in its above-captioned "2023 Base Rate Filing."

Please note that Exhibit JC-8 (Direct Testimony of Timothy S. Lyons on Class Cost of Service Study) contains certain confidential information. Accordingly, JCP&L is requesting confidential treatment of such information and has included herewith an Affidavit of Confidentiality in support of this request. JCP&L is filing both Confidential and Redacted (Public) versions of Exhibit JC-8 with the Board. A copy of the Confidential version of JC-8 will be provided to the Division of Rate Counsel upon the execution of the standard form of non-disclosure agreement for this matter.

These documents are being filed with the Acting Board Secretary electronically only, consistent with the Board's Order dated March 19, 2020 (Docket No. EO20030254) directing that all submissions to the Board, of any kind, be submitted electronically. I hereby confirm that copies each of this letter and the enclosed Verified Petition and supporting documents are on this day being duly served via electronic mail upon the Director, Division of Rate Counsel, and upon the Department of Law & Public Safety, Division of Law. We would appreciate if the Board Secretary's office would please acknowledge receipt of this filing.

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Your anticipated courtesies and cooperation are deeply appreciated.

Respectfully submitted,

COZEN O'CONNOR

By: Gregory Eisenstark

Enclosures

cc: Service List via electronic mail (*via E-mail*)

In the Matter of the Verified Petition of Jersey Central Power & Light Company For Review and Approval of Increases in, and Other Adjustments to, Its Rates and Charges For Electric Service, and For Approval of Other Proposed Tariff Revisions in Connection Therewith
("2023 Base Rate Filing")
BPU Dkt. No.:

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In the Matter of the Verified Petition of Jersey Central Power & Light Company For Review and Approval of Increases in, and Other Adjustments to, Its Rates and Charges For Electric Service, and For Approval of Other Proposed Tariff Revisions in Connection Therewith
("2023 Base Rate Filing")
BPU Dkt. No.:

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In the Matter of the Verified Petition of Jersey Central Power & Light Company for Review and Approval of Increases in, and Other Adjustments to, Its Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith ("2023 Base Rate Case")

AFFIDAVIT
OF
CONFIDENTIALITY

Mark A. Mader, of full age, being duly sworn upon her oath, deposes and says:

1. I am employed by FirstEnergy Service Company as Director, Rates and Regulatory Affairs – New Jersey. In this role, I am responsible for the management and oversight of Jersey Central Power & Light Company's ("JCP&L" or the "Company") regulatory filings, including base rate cases. I am duly authorized to make this Affidavit of Confidentiality on behalf of JCP&L in connection with the above-referenced proceeding. On March 16, 2023, JCP&L filed the above-referenced Verified Petition, including pre-filed direct testimony and schedules.

2. In connection with the above-captioned matter, Timothy S. Lyons filed direct testimony and schedules on cost of service issues, including cost of service studies. Mr. Lyons' direct testimony is marked as Exhibit JC-8 and includes two supporting schedules (TSL-1 and TSL-2). I have reviewed the testimony and schedules and am familiar with the information within them. The testimony and schedules all contain confidential information. Accordingly, the confidential versions of the testimony and schedules have been marked "Confidential" (and are referred to in this affidavit as the "Confidential Schedules"). In addition, redacted (or "Preliminary Public") copies of the testimony and schedules are also included with the rate case filing. The information that has been redacted from the Confidential Schedules, in the course of preparing the

Preliminary Public version, is referenced herein as the "Confidential Information."

3. The Direct Testimony of Timothy S. Lyons, Exhibit JC-8, and Confidential Schedules TSL-1 and TSL-2 contain individual customer proprietary information. More specifically, JCP&L has a single customer under rate schedule GT, Special Provision D ("GT_D"). Therefore, certain data identified in Exhibit JC-8 and in corresponding Schedules TSL-1 and TSL-2 with respect to that rate classification constitute individual customer proprietary information. I have been advised that, under New Jersey law, a public utility cannot disclose individual customer proprietary information without that customer's prior consent.

4. By way of substantiating the claim of confidentiality, I hereby verify that:

a. JCP&L has taken measures to prevent the disclosure of the Confidential Information to others, by restricting its dissemination even within the Company, and among JCP&L's counsel, on a "need to know" basis.

b. The Confidential Information is not contained in materials which are routinely made available to the general public, such as Initial and Final Orders in contested case adjudications, press releases, speeches, pamphlets and educational materials.

c. The Confidential Information has not been disclosed to others except pursuant to confidentiality agreements or as set forth in paragraph (a) above on a strict need-to-know basis, in which case the recipients of such need-to-know disclosures are professionally obliged to refrain from making further disclosure.

d. No relevant confidentiality determinations have previously been made by the Board, the Board's custodian of records, or any other state or federal agency or court of competent jurisdiction regarding the Confidential Information.

e. Public disclosure or release of the Confidential Information would have a harmful effect on JCP&L and JCP&L's customer because of the reasons set forth hereinabove.

5. I certify that the foregoing statements made by me are true. I am aware that if any of the foregoing statements made by me are willfully false, I am subject to punishment.

Mark A. Mader

Sworn to and subscribed electronically
this 16th day of March, 2023

Gregory Eisenstark
Attorney At Law of the State
of New Jersey

The undersigned attorney, Gregory Eisenstark, certifies that the affiant electronically acknowledged the genuineness of the signature.

Gregory Eisenstark, Esquire

STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

In the Matter of the Verified Petition of Jersey Central Power & Light Company For Review And Approval of Increases in, and Other Adjustments to, Its Rates and Charges For Electric Service, and For Approval of Other Proposed Tariff Revisions in Connection Therewith (**"JCP&L 2023 Base Rate Filing")**	:	Docket No. **VERIFIED PETITION**

TO THE HONORABLE BOARD OF PUBLIC UTILITIES:

Petitioner Jersey Central Power & Light Company (the "Petitioner", the "Company", or "JCP&L"), an electric public utility company of the State of New Jersey subject to the regulatory jurisdiction of the Board of Public Utilities (the "Board"), and maintaining offices at 101 Crawfords Corner Road, Building #1, Suite 1-511, Holmdel, New Jersey 07733 and at 300 Madison Avenue, Morristown, New Jersey 07962-1911, in support of its above-captioned Verified Petition, respectfully shows:

1. JCP&L is a New Jersey electric public utility primarily engaged in the purchase, transmission, distribution, and sale of electric energy and related utility services to more than 1.1 million residential, commercial, and industrial customers located within 13 counties and 236 municipalities of the State of New Jersey.

2. JCP&L is a wholly-owned subsidiary of FirstEnergy Corp. ("FirstEnergy"), which is a public utility holding company with a combined utility service area encompassing approximately 65,000 square miles in Ohio, Pennsylvania, West Virginia, Maryland, New Jersey, and New York. FirstEnergy Service Company ("FESC") is a wholly-owned mutual service

company subsidiary of FirstEnergy providing corporate and other centralized services to its parent and affiliates within the FirstEnergy holding company system. FESC is an affiliate of JCP&L.

3. Copies of all correspondence and other communications relating to this proceeding should be addressed to:

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INTRODUCTION

4. JCP&L's current base electric distribution rates ("base rates") were established by the Board's October 28, 2020 Order in Docket No. ER20020146, effective November 1, 2021 (the "2020 Base Rate Filing"). Even with that increase, JCP&L's customers have continued to enjoy electric service rates well below those of other New Jersey electric distribution companies ("EDCs").

5. Over the past several years since the end of the test year in the 2020 Base Rate Filing, JCP&L has made, and continues to make, significant investments in its system to enhance its resiliency, service, and reliability for its customers. From June 30, 2020 (the end of the test year of JCP&L's 2020 Base Rate Filing) through December 31, 2022, the Company has made $663.4 million in distribution capital investments and anticipates making another $130.8 million in capital investments in the first six months of 2023 (for an estimated total capital investment of $794.2 million). During this period, JCP&L has made several major capital investments to enhance its distribution system, including several significant substation upgrades and the further deployment of the Company's distribution automation program. JCP&L will continue to invest in its system to provide customers with safe and reliable service, and the requested rate increase in

this 2023 Base Rate Filing will help provide the necessary financial support for JCP&L to continue making such investments and providing its customers with quality electric service they have come to expect.

6. JCP&L has also been recognized for its storm restoration efforts in New Jersey and the rest of its system over the past several years, as FirstEnergy has been awarded the Emergency Recovery Award every year from 2011-2022 by the Edison Electric Institute ("EEI") to recognize extraordinary efforts to restore power or for assisting other electric companies after service disruptions caused by weather conditions and other natural events. EEI also awarded FirstEnergy the Emergency Response Award in 2019 and 2021 for its emergency response efforts. The Company's storm processes and programs comply with industry standards and the Board's regulatory requirements as found in regulations or applicable Board orders, including the most recent storm-related Board order after Tropical Storm Isaias. Relative to deferred storm costs, even taking into account the results of the 2020 Base Rate Filing, the Company has incurred additional significant deferred storm costs of approximately $205.2 million, of which, approximately $148.5 million was attributable to Tropical Storm Isaias, resulting in a current total balance of almost $310 million as of December 31, 2022. The amounts deferred represent prudently incurred costs to prepare for, pre-stage resources when necessary, and to carry out the storm recovery and restoration processes. JCP&L seeks to recover the increased amount of its deferred storm balance in this proceeding as proposed by Mr. Mader in his Direct Testimony at Exhibit JC-2.

7. Furthermore, JCP&L has taken steps to financially strengthen its balance sheet. The effect of a $500 million long-term debt issuance in June 2021 resulted in a decrease of 51.1 basis points in the long-term debt cost rate. In addition, in October 2021, FirstEnergy established

six individual revolving credit facilities, including one for each of the states in which FirstEnergy has operating utilities, one of which is a JCP&L-specific revolving credit facility. JCP&L now has its own revolving credit facility, with a commitment of $500 million that is equal to its Federal Energy Regulatory Commission authorized short-term borrowing authority. The purpose of this step was to strengthen JCP&L as a stand-alone entity by diminishing the financial linkages between JCP&L, its parent, FirstEnergy Corp, and FirstEnergy's other subsidiaries.

8. JCP&L's request in this proceeding also includes investments and expenses associated with the Company's implementation of its advanced metering infrastructure ("AMI") and electric vehicle ("EV" Driven") programs. Certain costs associated with these programs, which were approved by the Board to support the attainment of the State's aggressive clean energy goals, are included as part of the of the Company's rate request.

9. As a result of the above-referenced extensive storm-related work, its capital investments and operating and maintenance expenses ("O&M"), and its investments in support of the State's clean energy goals, JCP&L's current base rates are not sufficient for the Company to earn an appropriate rate of return on its rate base or to recover its annual O&M expense. As a result, JCP&L is proposing a rate increase of $184.95 million on an annual basis, representing an overall average increase in JCP&L rates of 6.8%.

10. This base rate proceeding will provide an opportunity for JCP&L's rates to be properly adjusted to allow the Company to attract the necessary capital resources to continue to provide its customers with safe and reliable electric distribution service, as well as recover previously-incurred storm costs and other program costs in support of New Jersey's Energy Master Plan. Importantly, following this necessary increase in rates, JCP&L's residential rates (RS) will continue to be the lowest electric service rates compared to New Jersey's other EDCs.

2023 BASE RATE FILING

11. In this filing, the Company uses a test year of the twelve months ending June 30, 2023 (the "Test Year"). The filing includes six months of actual data (July 1, 2022 through December 31, 2022) and six months of forecasted data (January 1, 2023 through June 30, 2023), along with certain post-test year adjustments in accordance with the Board's long-standing *Elizabethtown Water*[1] standards. JCP&L plans to file "9+3" and "12+0" updates during the course of this proceeding.

12. In its Order of Approval dated October 9, 2001 in Docket No. EM00110870 (the "FE/GPU Merger Order"), the Board approved (with certain modifications) a Stipulation of Settlement regarding the merger of JCP&L's then parent company, GPU, Inc., with FirstEnergy. With respect to JCP&L's capital structure for ratemaking purposes, the FirstEnergy/GPU Merger Order provides:

> JCP&L shall file, in all future base rate cases, its case using two alternative capital structures. One of the alternatives shall be a consolidated capital structure based on the capital structure that is maintained by FirstEnergy (the holding company). The second alternative shall be a stand-alone JCP&L capital structure. The parties to future base rate cases shall be free to argue for the benefits of using either capital structure for ratemaking purposes or another alternative.[2]

The FirstEnergy/GPU Merger Order also directed that:

> JCP&L shall maintain a capital structure, dividend policy, and use its best efforts to achieve financial target ratios consistent with investment grade debt ratings as reported by Moody's Investors Service and Standard & Poor's.[3]

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[1] *In re Elizabethtown Water Co.*, BPU Docket No. WR850433085 (Order dated May 23, 1985), at 2.

[2] *I/M/O The Joint Petition of FirstEnergy Corp.. and Jersey Central Power and Light Company, D/B/A GPU Energy for Approval of a Change in Ownership and Acquisition of Control of a New Jersey Public Utility and Other Relief*, BPU Docket No. EM00110870 (Order dated October 9, 2001), at 23, ¶16.

[3] *Id.* at 23, ¶17.

JCP&L's 2023 Base Rate Filing complies with these directives.

13. JCP&L's 2023 Base Rate Filing further complies with all other provisions of the Board's FE/GPU Merger Order, more particularly including those provisions relating to the potential impact of the merger on JCP&L's rates.[4]

14. In an Order dated February 10, 2011 in Docket No. EM11010012 (the "FE/Allegheny Merger Order"), the Board accepted a Stipulation ("January 18, 2011 Stipulation") relating to the proposed acquisition by FirstEnergy, the parent company of JCP&L, of Allegheny Energy, Inc. The January 18, 2011 Stipulation provides, among other things, that:

> If in future rate proceedings involving determinations of return on equity ("ROE") JCP&L files ROE testimony that includes a "comparables" analysis as has been the general practice in rate proceedings, JCP&L will, to the extent reasonable, include in the "comparables" group "distribution only" utilities or utilities with the majority of their assets under regulation, but may include other types of "comparables" as deemed appropriate by its expert ROE witness.[5]

JCP&L's 2023 Base Rate Filing complies with this directive.

15. Further, the Board's orders approving JCP&L's EV Driven program,[6] Energy Efficiency and Conservation Plan,[7] and AMI Program[8] each respectively required that the

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[4] *Id.* at 22-23, ¶¶12-22.

[5] *I/M/O the Business Combination of FirstEnergy Corp., Parent Company of Jersey Central Power and Light Company, and Allegheny Energy, Inc.*, BPU Docket No. EM11010012, January 18, 2011 Stipulation at ¶11.

[6] *I/M/O The Verified Petition of Jersey Central Power & Light Company for Approval of an Electric Vehicle Program and an Associated Cost Recovery Mechanism, BPU Docket No. EO21030630, Decision and Order Approving Stipulation,* June 8, 2022. ("EV Order").

[7] *I/M/O the Implementation of L. 2018, c. 17 Regarding the Establishment of Energy Efficiency and Peak Demand Reduction Programs*, BPU Docket No. QO19010040*;* and *I/M/O the Verified Petition of Jersey Central Power and Light Company for Approval of JCP&L's Energy Efficiency and Conservation Plan Including Energy and Peak Demand Reduction Programs (JCP&L EE&C)* BPU Docket No. EO20090620, Order Adopting Stipulation, April 27, 2021.

[8] *I/M/O the Verified Petition of Jersey Central Power and Light Company for Approval of an Advanced Metering Infrastructure (AMI) Program*, BPU Docket No. EO20080545, Decision and Order Approving Stipulation, February 23, 2022. ("AMI Order").

Company file a base rate case no later than July 1, 2026. This filing satisfies the requirement from those orders.

16. Even with the increase approved as a result of the 2020 Base Rate Filing, JCP&L's residential rates (delivery and total, including basic generation service ("BGS")),[9] continue to be the lowest among the State's four EDCs. At the same time, the Company continues to invest in its distribution system to provide safe, adequate, and proper service. The Company has also begun to undertake, and plans to continue undertaking, significant investment in programs supporting the State's clean energy and grid modernization objectives, such as JCP&L's EV Driven and AMI programs. The rate relief requested in this filing will assist JCP&L with continuing to make these important system investments while ramping up these programs supporting New Jersey's goals.

SUMMARY OF PROPOSED RATE ADJUSTMENT

17. Based upon JCP&L's current base rates, the new rates proposed herein would result in an overall average increase in JCP&L's rates of approximately $184.95 million annually, or an average increase in JCP&L rates of 6.8%.

18. A typical JCP&L residential customer using 780 kWh per month currently pays, on average, $113.21 per month for electricity. The implementation of the requested rate adjustment would increase that typical residential monthly bill by $8.45 or 7.5%, resulting in an average monthly bill payment of $121.66.

OTHER PROPOSED TARIFF REVISIONS

19. JCP&L proposes to revise certain of the terms and conditions of its existing tariff for electric service, as currently set forth in its Tariff For Service, BPU No. 13 – ELECTRIC.

[9] "Delivery" refers to the distribution rate plus the non-bypassable rate charges and taxes; "total" refers to the delivery rate plus BGS charges.

Copies of the proposed revised tariff sheets are included as Schedule YP-1 to the Direct Testimony of Yongmei Peng (Exhibit JC-9). Ms. Peng's testimony sets forth the proposed tariff changes and the reasons for same.

20. In addition, JCP&L proposes certain additional changes to its Sodium Vapor Street Lighting ("SVL") tariff to phase-out such tariff and its LED Street Lighting tariff to add an additional service offering. Mr. Mader explains the reasons for these proposed changes in his Direct Testimony (Exhibit JC-2), which proposed changes are also set forth in Ms. Peng's Schedule YP-1. The Company also proposes two additional Low-Income Assistance Initiatives in the form of an Energy Outreach Team and a Senior Citizen Discount Program, which are discussed in the Direct Testimony of Mr. Kenneth Strah (Exhibit JC-13). Finally, the Company is also proposing a Pension/OPEB Normalization Mechanism ("PON Mechanism"), which is discussed in the Direct Testimony of Ms. Tracy Ashton (Exhibit JC-4).

DEPRECIATION RATES

21. The Company is filing a new depreciation study and proposing modifications to its depreciation accrual rates. John J. Spanos is sponsoring the depreciation study and related Direct Testimony (Exhibit JC-10).

AMI AND EV DRIVEN PROGRAM INVESTMENTS AND COSTS

22. In accordance with the deferral and recovery mechanisms established in the proceedings approving the Company's AMI and EV Driven programs, JCP&L has deferred its investments and expenses for each program and seeks recovery of same as part of this filing. The Direct Testimony of John Ahr (Exhibit JC-12) addresses the Company's AMI investments and expenses as well as forecasted capital investments through December 31, 2023. The Direct

Testimony of Carol A. Pittavino (Exhibit JC-3) addresses the Company's investments and expenses associated with the EV Driven program.

23. In addition, the EV Order explains:

> The Signatory Parties agree the Next Base Rate Case will remain open solely for the purpose of including the EV investment placed in service more than six (6) months after the end of the test year in the Next Base Rate Case will be reviewed and placed into rates, if deemed reasonable and prudent, as soon as practicable after the associated infrastructure has been placed into service, through annual roll-in filings following the Next Base Rate Case. The annual roll in filings will include three (3) months of forecast data that will be trued-up with actual data no later than 20 days after the end of the final forecast month. The annual roll-in filing will request that new rates be implemented three (3) months after the end of the final forecast month. The schedule of such annual roll-in filings shall be determined in the Company's Next Base Rate Case. The Company shall make annual roll-in filings until all EV Program costs have been submitted to the Board for review and, if deemed reasonable and prudent by the Board, rolled into base rates.

EV Order at p. 12

Similarly, the AMI Order explains that:

> AMI Plan-related capital investment that is not likely to be in-service by the end of six (6) months after the end of the test year, shall be deferred and placed in the AMI Investment Regulatory Asset (defined in paragraph 33 of the Stipulation), and reviewed and recovered in base rates, if deemed reasonable and prudent, in a subsequent base rate case. However, in the event that JCP&L is not able to implement the full AMI Plan investment within six (6) months of the end of the test year in a subsequent base rate case that is associated with the end of full deployment (full deployment occurs at the conclusion of the Company's Deployment Phase as defined in paragraph 25 of the Stipulation), JCP&L may request that it be permitted to hold that base rate case open for the purpose of rolling those reasonable and prudent costs into rates as soon as practicable after the associated infrastructure has been placed into service and associated stranded costs have been incurred. The Signatory Parties reserve their rights to challenge the Company's request if JCP&L requests to hold open such base rate case, and acceptance of the terms of the Stipulation in this proceeding does not constitute acceptance of such a request.

AMI Order at p. 8.

Accordingly, as a result of the EV Order and the AMI Order, the Company hereby requests that this 2023 Base Rate Filing remain open solely for the purpose of the roll-in of the EV Driven and AMI costs discussed above.

EV COST OF SERVICE STUDY

24. In accordance with the requirements set forth in the Stipulation of Settlement addressing the Company's EV Driven program, the Direct Testimony of Timothy Lyons (Exhibit JC-8) includes a section addressing the cost of service for customers utilizing electric vehicle chargers in JCP&L's service territory.

RATE EFFECTIVE DATE

25. JCP&L is proposing a rate effective date of April 26, 2023 which is not less than 30 days after the filing of this Petition. JCP&L expects that the Board will follow its normal procedures for issuing the two statutory suspension orders, which would result in the Company's revised base rates becoming effective at the end of the second suspension period, in December 2023.

PROPOSED PROCEDURAL SCHEDULE

26. JCP&L proposes that the procedural schedule be utilized for the Company's filing, consistent with the provisions of N.J.S.A. 48:2-21(d). A proposed procedural schedule is provided as Attachment A to this Verified Petition.

PREFILED TESTIMONY AND EXHIBITS

27. Attached hereto and made a part of this Verified Petition are the following prefiled direct testimonies in support of the Company's petition:

Witness	**Exhibit No.**	**Topics**
Mark A. Mader	JC-2	Overview and Requested Rate Relief, Amortization of Deferred Storm Expense, Revenue Normalization Adjustment, Consolidated Tax Adjustment, Street Lighting Tariff Changes, Contract Labor and Fuel Cost Adjustments, and Return on AMI Stranded Cost Regulatory Asset
Carol A. Pittavino	JC-3	Revenue Requirements
Tracy M. Ashton	JC-4	Pension/OPEB Expense, OPEB Accounting and Ratemaking Adjustments, and Service Company Relationships, Charges and Allocations
Dennis L. Pavagadhi	JC-5	JCP&L Operations, O&M Expenditures, Capital Investments, Reliability, and Tariff Appendix A
Bill Wang	JC-6	Capital Structure and Cost of Capital
Dylan W. D'Ascendis	JC-7	Return on Common Equity
Timothy S. Lyons	JC-8	Class Cost of Service Study
Yongmei Peng	JC-9	Tariff Revisions and Design of the Proposed Distribution Rates
John J. Spanos	JC-10	Depreciation Study and Proposed Depreciation Accrual Rates
Timothy S. Lyons	JC-11	Cash Working Capital
John C. Ahr	JC-12	JCP&L Advanced Metering Infrastructure Program
Kenneth A. Strah	JC-13	Customer Care and Low-income Initiatives

PUBLIC NOTICE AND SERVICE OF FILING

28. In accordance with N.J.A.C. 14:1-5.12(b), once an agreed-upon time and date has been established for public hearings in this matter, notice of this JCP&L 2023 Base Rate Filing and the hearings thereon will be served by mail upon the municipal clerks, the clerks of the Boards of County Commissioners, and, where appropriate, the County Executive Officers, of all counties and municipalities located in the Company's service territory. Such notice will be substantially in the form of the notice annexed hereto as **Appendix A** and will be mailed following the scheduling of dates and times for virtual public hearings on the Company's petition. Appendices A-1, A-2 and A-3 hereto include listings of the aforementioned public officials to whom notice will be provided. Additionally, once an agreed-upon time and date has been established for public hearings in this matter, notice of same will also be published in the daily and weekly newspapers published and/or circulated in the Company's service areas.

ADDITIONAL INFORMATION

29. In accordance with N.J.A.C. 14:1-5.12, attached hereto are the following required items of additional information and financial statements:

Appendix B - Comparative Balance Sheets at December 31, 2019, 2020 and 2021

Appendix C - Comparative Income Statements For the Calendar Years Ending December 31, 2019, 2020 and 2021

Appendix D - Balance Sheet at December 31, 2021

Appendix E - Statement of the Amount of Revenue Derived in Calendar Year 2021 From Intrastate Sales and Services at Current Rates

Appendix F - Pro Forma Income Statement Reflecting Operating Income at Present and Proposed Rates, With Explanation of All Adjustments Thereon and Calculation of Indicated Rates of

Return on Pro Forma Rate Base. Note that the information specified in this filing requirement is provided in Schedules CAP-1 and CAP-4 to the Direct Testimony of Carol A. Pittavino (Exhibit JC-3).

Appendix G - Itemized Schedule of Payments or Accruals to Affiliates

Appendix H - Proposed Revised Tariff Sheets. Note that Appendix H is provided as Schedule YP-1 to the Direct Testimony of Yongmei Peng (Exhibit JC-9).

SERVICE OF PETITION

30. Consistent with the Board's March 19, 2020 Order in Docket No. EO20030254, copies of this filing are being served upon the Department of Law and Public Safety and upon the Director of the Division of Rate Counsel by electronic mail only.

WHEREFORE, the Petitioner, Jersey Central Power & Light Company, respectfully requests that the Board issue a final decision and order:

(1) approving and accepting the revised rates and charges for electric service as proposed herein, to become effective for service rendered on and after April 26, 2023;

(2) approving and accepting the attached revised tariff sheets for inclusion in JCP&L's Tariff For Service, BPU No. 14 – Electric, effective for service rendered on and after April 26, 2023;

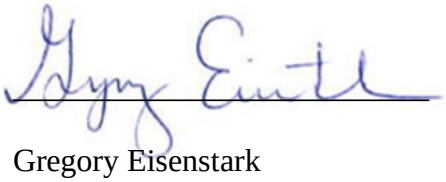
(3) approving all other requests for relief as set forth in this Petition, pre-filed testimony and supporting schedules;

(4) consistent with the EV Order and the AMI Order, leaving open this proceeding solely for the limited purpose of allowing for the roll-in of certain costs associated with the Company's EV Driven and AMI programs; and

(5) granting such other and further relief as the Board shall deem just, lawful and proper.

Respectfully submitted,

COZEN O'CONNOR, P.C.
Attorneys for Petitioner,
Jersey Central Power & Light Company

Dated: March 16, 2023 By: 

Gregory Eisenstark
1010 Kings Highway South
Cherry Hill, New Jersey 08034
(973) 200-7411
geisenstark@cozen.com

Affidavit
of
Verification

I, Mark A. Mader, being duly sworn upon his oath, deposes and says:

1. I am the Director of Rates & Regulatory Affairs – New Jersey for FirstEnergy Service Company and I am duly authorized to make this Affidavit of Verification on behalf Jersey Central Power & Light Company ("JCP&L"), the Petitioner in this matter.

2. I have read the contents of the foregoing Verified Petition by JCP&L for review and approval of the proposed increase in and other adjustments to its rates and charges for electric service and for approval of other proposed tariff revisions in connection therewith, and I hereby verify that the statements of fact and other information contained therein are true and correct to the best of my knowledge, information and belief.

Mark A. Mader

Sworn to and subscribed electronically
this 16th day of March, 2023.

Gregory Eisenstark
Attorney At Law of the State
of New Jersey

The undersigned attorney, Gregory Eisenstark, certifies that the affiant electronically acknowledged the genuineness of the signature.

Gregory Eisenstark, Esquire

APPENDIX A

PUBLIC NOTICE

JERSEY CENTRAL POWER & LIGHT COMPANY

NOTICE OF PROPOSED RATE INCREASES AND OTHER ADJUSTMENTS WITH RESPECT TO JCP&L'S TARIFF RATES AND CHARGES FOR ELECTRIC SERVICE, AND WITH RESPECT TO OTHER PROPOSED TARIFF CHARGES AND REVISIONS

AND

NOTICE OF PUBLIC HEARINGS THEREON

TO OUR CUSTOMERS:

On March 16, 2023, Jersey Central Power & Light Company ("JCP&L" or the "Company"), filed a Verified Petition with the New Jersey Board of Public Utilities (the "Board"), under BPU Docket No. _____, together with supporting appendices, testimony, exhibits and schedules and revised Tariff sheets.

The Verified Petition seeks the Board's approval of proposed overall increases in and/or other adjustments to JCP&L's various Tariff rates and charges for electric service, and for approval of other proposed Tariff charges and revisions, which are proposed to become effective for service rendered on and after April 26, 2023, or at such later date as the Board may determine.

Based on the Verified Petition, the proposed new rates would yield an overall net operating revenue increase of approximately $184.95 million, representing an overall revenue increase of about 6.8% as compared to the same current annualized Tariff rates and revenues. The annual percentage increase applicable to specific customers will vary according to the applicable rate schedule and the level of the customer's usage.

APPENDIX A

Copies of the Verified Petitions and all related documents are available for inspection at the Company's regional headquarters at 101 Crawfords Corner Rd. Building #1, Suite 1-511, Holmdel, New Jersey 07733 and at 300 Madison Avenue, Morristown, New Jersey 07962-1911, at each of the Company's local business offices, and at the Board of Public Utilities, 44 South Clinton Avenue, Trenton, New Jersey 08625. A copy of the filing will also be posted on the Company's website at:

https://www.firstenergycorp.com/jersey_central_power_light/regulatory.html

The following comparisons of present and proposed rates will permit customers to determine the approximate net effect upon them of the proposed increases and adjustments in rates. Any assistance required by customers in this regard will be furnished by the Company upon request. Please note that the Board in its discretion may apply all or any portion of whatever rate increases the Board may ultimately allow to other rate schedules or in a different manner than what JCP&L has proposed in its filings. Accordingly, the final rates and charges to be determined by the Board in this proceeding may be different than what JCP&L has described herein.

SUMMARY OF CUSTOMER IMPACT

	Overall Class Average Per Customer (Includes 6.625 % Sales and Use Tax)		
Rate Class	Current Monthly Bill (1)	Proposed Monthly Bill (2)	Proposed Monthly Increase %
Residential (RS)	$115.46	$124.36	7.7%
Residential Time of Day (RT/RGT)	$161.75	$174.17	7.7%
General Service – Secondary (GS)	$574.65	$617.06	7.4%
General Service - Secondary Time of Day (GST)	$31,361.54	$32,897.37	4.9%
General Service – Primary (GP)	$31,232.55	$32,437.92	3.9%
General Service – Transmission (GT)	$115,439.76	$118,605.40	2.8%
Lighting (Average Per Fixture)	$11.26	$12.42	10.3%
(1) Rates effective 3/1/2023			
(2) Proposed rates effective TBD			

APPENDIX A

The Company has also proposed other Tariff revisions and related charges, some of which would apply to all customers and others that would apply only to those customers whose requests or actions give rise to the related costs. Descriptions of all such proposed Tariff revisions are included in Exhibits JC-2, JC-5, and JC-9, and their associated schedules.

Notice of these filings together with a statement of the effect thereof on customers are being served upon the clerk, executive or administrator of each municipality and county within the Company's service areas. Such notice has also been served, together with the Verified Petitions, Tariffs, rate schedules and all other exhibits, upon the Director of the Division of Rate Counsel, who will represent the interests of ratepayers in these proceedings.

PLEASE TAKE NOTICE that the New Jersey Office of Administrative Law has scheduled virtual public hearings on the Verified Petition under OAL Docket No. _____ on the following dates and times:

Members of the public will have an opportunity to be heard and/or to submit written comments or statements at each or any of the public hearings if they wish to do so. Such written comments or statements may also be submitted directly the Clerk of the Office of Administrative Law, 33 Washington Street, Newark, NJ 07102.

Dated: _____, 2023 **JERSEY CENTRAL POWER & LIGHT COMPANY**

List of Municipal Clerks

Clerk, Township of Aberdeen
1 Aberdeen Square
Aberdeen, NJ 07747

Clerk, Township of Alexandria
242 Little York-Mt. Pleasant Rd.
Milford, NJ 08848

Clerk, Township of Allamuchy
292 Alphano Rd.
PO Box A
Allamuchy, NJ 07820

Clerk, Borough of Allenhurst
125 Corlies Avenue
Allenhurst, NJ 07711

Clerk, Borough of Alpha
1001 E. Boulevard
Alpha, NJ 08865

Clerk, Borough of Andover
137 Main Street
Andover, NJ 07821

Clerk, Andover Township
134 Newton-Sparta Road
Newton, NJ 07860-2746

Clerk, City of Asbury Park
One Municipal Plaza Asbury
Park, NJ 07712

Clerk, Borough of Atlantic Highlands
Municipal Building
100 First Avenue
Atlantic Highlands, NJ 07716

Clerk, Borough of Avon By The Sea
Municipal Building
301 Main Street
Avon By The Sea, NJ 07717

Clerk, Township of Barnegat
900 W. Bay Avenue
Barnegat, NJ 08805-1298

Clerk, Borough of Bay Head
81 Bridge Avenue
PO Box 248
Bay Head, NJ 08742

Clerk, Borough of Beachwood
1600 Pinewald Rd.
Beachwood, NJ 08722

Clerk, Bedminster Township
One Miller Lane
Bedminster, NJ 07921

Clerk, Borough of Belmar
601 Main Street
PO Box A
Belmar, NJ 07719-0070

Clerk, Town of Belvidere
691 Water Street
Belvidere, NJ 07823

Clerk, Township of Berkeley
627 Pinewald–Kenswick Rd.
PO Box B
Bayville, NJ 08721-0287

Clerk, Township of Berkeley Heights
29 Park Avenue
Berkeley Heights, NJ 07922-1499

Clerk, Bernards Township
1 Collyer Lane
Basking Ridge, NJ 07920-1441

Clerk, Borough of Bernardsville
Borough Hall - 166 Mine Brook Road
PO Box 158
Bernardsville, NJ 07924-0158

Clerk, Township of Bethlehem
405 Mine Road
Asbury, NJ 08802-1107

Clerk, Township of Blairstown
106 Route 94
Blairstown, NJ 07825

Clerk, Borough of Bloomingdale
Municipal Building
101 Hamburg Turnpike
Bloomingdale, NJ 07403

Clerk, Borough of Bloomsbury
91 Brunswick Avenue
Bloomsbury, NJ 08804-0098

Clerk, Town of Boonton
100 Washington Street
Boonton, NJ 07005

Clerk, Township of Boonton
155 Powerville Road
Boonton, NJ 07005-8729

Clerk, Borough of Bradley Beach
701 Main Street
Bradley Beach, NJ 07720

Clerk, Township of Branchburg
1077 US Highway 202 N.
Somerville, NJ 08876-3936

Clerk, Borough of Branchville
34 Wantage Avenue
Branchville, NJ 07826-0840

Clerk, Borough of Brielle
601 Union Lane - PO Box 445
Brielle, NJ 08730-0445

List of Municipal Clerks

Clerk, Brick Township
401 Chambersbridge Road
Brick Town, NJ 08723

Clerk, Township of Bridgewater
100 Commons Way
Bridgewater, NJ 08807

Clerk, Borough of Butler
1 Ace Road
Butler, NJ 07405

Clerk, Township of Byram
10 Mansfield Drive
Stanhope, NJ 07874

Clerk, Borough of Califon
39 Academy Street
PO Box 368
Califon, NJ 07830-0368

Clerk, Borough of Chatham
Municipal Building
54 Fairmount Avenue
Chatham, NJ 07928-2393

Clerk, Township of Chatham
58 Meyersville Road
Chatham, NJ 07928

Clerk, Borough of Chester
Municipal Building
PO Box 487
50 North Road
Chester, NJ 07930

Clerk, Township of Chester
Municipal Building
1 Parker Road
Chester, NJ 07930

Clerk, Township of Chesterfield
Municipal Building
300 Bordentown-Chesterfield Road
Chesterfield, NJ 08515

Clerk, Town of Clinton
43 Leigh Street
Clinton, NJ 08809

Clerk, Township of Clinton
1370 Rte. 31 North
Annandale, NJ 08801

Clerk, Township of Colts Neck
Town Hall
124 Cedar Drive
Colts Neck, NJ 07722-0249

Clerk, Township of Cranbury
23A North Main Street
Cranbury, NJ 08512-3287

Clerk, Borough of Deal
Municipal Building
P.O. Box 56 - Durant Square
Deal, NJ 07723-0056

Clerk, Township of Denville
Municipal Building
1 St. Mary's Place
Denville, NJ 07834

Clerk, Township of Delaware
Township Hall
PO Box 500
Sergeantsville, NJ 08557

Clerk, Town of Dover
Town Hall
37 North Sussex Street
Dover, NJ 07801

Clerk, Township of Dover
33 Washington Street
PO Box 728
Toms River, NJ 08754-0728

Clerk, Township of East Amwell
1070 Rtes. 202 and 31
Ringoes, NJ 08551-1051

Clerk, Township of East Brunswick
1 Jean Walling Civic Center
PO Box 1081
East Brunswick, NJ 08816-1081

Clerk, Township of East Hanover
411 Ridgedale Avenue
East Hanover, NJ 07936

Clerk, Township of East Windsor
Municipal Building
16 Lanning Boulevard
East Windsor, NJ 08520-1999

Clerk, Borough of Eatontown
Borough Hall
47 Broad Street
Eatontown, NJ 07724-1698

Clerk, Borough of Englishtown
15 Main Street
Englishtown, NJ 07726

Clerk, Borough of Fair Haven
Municipal Building
748 River Road
Fair Haven, NJ 07704

Clerk, Borough of Far Hills
6 Prospect Street
Far Hills, NJ 07931

Clerk, Borough of Farmingdale
Municipal Building
11 Asbury Avenue
Farmingdale, NJ 07727

Clerk, Borough of Flemington
38 Park Avenue
Flemington, NJ 08822-1398

Clerk, Borough of Florham Park
Borough Hall
111 Ridgedale Avenue
Florham Park, NJ 07932

List of Municipal Clerks

Clerk, Township of Frankford
151 US Highway 206
Augusta, NJ 07822

Clerk, Borough of Franklin
46 Main Street
Franklin, NJ 07416

Clerk, Township of Franklin
475 DeMott Lane
Somerset, NJ 08873

Clerk, Township of Franklin
Municipal Building
2093 Rte. 57
PO Box 547
Broadway, NJ 08808

Clerk, Township of Fredon
443 Rte. 94
Newton, NJ 07860

Clerk, Borough of Freehold
51 West Main Street
Freehold, NJ 07728-2195

Clerk, Township of Freehold
One Municipal Plaza
Freehold, NJ 07728-3099

Clerk, Township of Frelinghuysen
210 Main Street
Johnsonburg, NJ 07825

Clerk, Borough of Frenchtown
Borough Hall
29 Second Street
Frenchtown, NJ 08825

Clerk, Borough of Glen Gardner
PO Box 307
Glen Gardner, NJ 08826

Clerk, Township of Green
150 Kennedy Road
PO Box 65
Tranquility, NJ 07879

Clerk, Township of Green Brook
111 Greenbrook Road
Greenbrook, NJ 08812-2501

Clerk, Township of Greenwich
321 Greenwich Street
Stewartsville, NJ 08886

Clerk, Town of Hackettstown
215 Stiger Street
Hackettstown, NJ 07840

Clerk, Borough of Hamburg
Municipal Building
16 Wallkill Avenue
Hamburg, NJ 07419

Clerk, Borough of Hampton
PO Box 418
Hampton, NJ 08827

Clerk, Township of Hampton
1 Rumsey Way
Hampton Twp., Newton, NJ 07860

Clerk, Township of Hanover
Municipal Building
1000 Rte. 10 - PO Box 250
Whippany, NJ 07981-0250

Clerk, Township of Harding
Harding Township Municipal Offices
PO Box 666
New Vernon, NJ 07976

Clerk, Township of Hardwick
40 Spring Valley Road
Blairstown, NJ 07825

Clerk, Township of Hardyston
Municipal Building, Suite A
149 Wheatsworth Rd.
Hamburg, NJ 07419

Clerk, Township of Harmony
3003 Belvidere Road
Phillipsburg, NJ 08865

Clerk, Township of Hazlet
1766 Union Avenue
Hazlet, NJ 07730

Clerk, Borough of Helmetta
Borough Hall
51 Main Street
Helmetta, NJ 08828

Clerk, Borough of High Bridge
71 Main Street
High Bridge, NJ 08829-1003

Clerk, Borough of Highlands
42 Shore Drive
Highlands, NBJ 07732-1699

Clerk, Borough of Hightstown
156 Bank Street
Hightstown, NJ 08520-3291

Clerk, Township of Hillsborough
379 S. Branch Road
Hillsborough, NJ 08844

Clerk, Township of Holland
61 Church Road
Milford, NJ 08848

Clerk, Township of Holmdel
4 Crawford's Corner Road
PO Box 410
Holmdel, NJ 07733-0410

List of Municipal Clerks

Clerk, Borough of Hopatcong
Municipal Building
111 River Styx Road
Hopatcong, NJ 07843-1599

Clerk, Township of Hope
PO Box 284
407 Hope-Great Meadows Rd
Hope, NJ 07844

Clerk, Township of Hopewell
Municipal Building
201 Washington Crossing Pennington Rd
Titusville, NJ 08560

Clerk, Township of Howell
PO Box 580
4567 Route 9 North
Howell, NJ 07731-0580

Clerk, Township of Independence
Municipal Building
286 Rte. 46 West, PO Box 164
Great Meadows, NJ 07838

Clerk, Borough of Interlaken
Borough Hall
100 Gasmere Avenue
Interlaken, NJ 07712

Clerk, Borough of Island Heights
Municipal Complex
East End & Van Sant Ave.
Island Heights, NJ 08732

Clerk, Township of Jackson
Municipal Building
95 West Veterans Highway
Jackson, NJ 08527

Clerk, Borough of Jamesburg
131 Perrineville Road
Jamesburg, NJ 08831

Clerk, Township of Jefferson
Municipal Building
1033 Weldon Road
Lake Hopatcong, NJ 07849

Clerk, Borough of Keansburg
Municipal Building
29 Church Street
Keansburg, NJ 07734

Clerk, Borough of Keyport
70 West Front Street
Keyport, NJ 07735-0070

Clerk, Township of Kingwood
599 Oak Grove Road & Route 519
Frenchtown, NJ 08825

Clerk, Borough of Kinnelon
Municipal Building
130 Kinnelon Road
Kinnelon, NJ 07405

Clerk, Township of Knowlton
Municipal Building
628 Rote. 94
Columbia, NJ 07832

Clerk, Township of Lacey
Municipal Building
818 W. Lacey Road
Forked River, NJ 08731

Clerk, Township of Lafayette
33 Morris Farm Road
Lafayette, NJ 07848

Clerk, Borough of Lakehurst
5 Union Avenue
Lakehurst, NJ 08733-3097

Clerk, Township of Lakewood
Municipal Building
231 Third Street
Lakewood, NJ 08701-3220

Clerk, City of Lambertville
18 York Street
Lambertville, NJ 08530

Clerk, Borough of Lavallette
1306 Grand Central Ave.
Lavallette, NJ 08735

Clerk, Borough of Lebanon
6 High Street
Lebanon, NJ 08833

Clerk, Township of Lebanon
530 W. Hill Road
Glen Gardner, NJ 08826-9714

Clerk, Township of Liberty
349 Mtn. Lake Road
Great Meadows, NJ 07838

Clerk, Borough of Lincoln Park
Municipal Building
34 Chapel Hill Road
Lincoln Park, NJ 07035-1998

Clerk, Borough of Little Silver
Borough Hall
480 Prospect Avenue
Little Silver, NJ 07739

Clerk, Township of Livingston
357 S. Livingston Avenue
Livingston, NJ 07039-3994

Clerk, Village of Loch Arbour
550 Main Street
Loch Arbour, NJ 07711

Clerk, City of Long Branch
City Hall
344 Broadway
Long Branch, NJ 07740

Clerk, Township of Lopatcong
Municipal Building
232 South Third St. - Morris Park
Phillipsburg, NJ 08865-1898

List of Municipal Clerks

Clerk, Borough of Madison
Hartley Dodge Memorial Building
50 Kings Road
Madison, NJ 07940-2592

Clerk, Township of Manalapan
120 Route 522 & Taylor-Mills Road
Manalapan Township, NJ 07726

Clerk, Borough of Manasquan
201 E. Main Street
Manasquan, NJ 08736

Clerk, Township of Manchester
1 Colonial Drive
Manchester Township, NJ 08759

Clerk, Township of Mansfield
3135 Route 206 South – Suite 1
Columbus, NJ 08022-0249

Clerk, Borough of Mantoloking
Borough Hall
PO Box 4391
Brick, NJ 08738

Clerk, Township of Maplewood
Municipal Building
574 Valley Street
Maplewood, NJ 07940-0690

Clerk, Township of Marlboro
Municipal Complex
1979 Township Drive
Marlboro, NJ 07746

Clerk, Borough of Matawan
201 Broad Street
Matawan, NJ 07747

Clerk, Borough of Mendham
2 W. Main Street
Mendham, NJ 07945

Clerk, Township of Middletown
Municipal Building
1 Kings Highway
Middletown, NJ 07748-2594

Clerk, Borough of Milford
30 Water Street
PO Box 507
Milford, NJ 08848-0507

Clerk, Township of Millburn
Town Hall
375 Millburn Avenue
Millburn, NJ 07041-1379

Clerk, Township of Millstone
Municipal Building
470 Stage Coach Road
Clarksburg, NJ 08510

Clerk, Township of Mine Hill
Municipal Building
10 Baker Street
Mine Hill, NJ 07803

Clerk, Borough of Monmouth Beach
22 Beach Road
Monmouth Beach, NJ 07750

Clerk, Monroe Township
Municipal Complex
1 Municipal Plaza
Monroe Township, NJ 08831-1900

Clerk, Township of Montague
277 Clove Road
Montague, NJ 07827

Clerk, Borough of Netcong
Municipal Building
23 Maple Avenue
Netcong, NJ 07857-1121

Clerk, Township of New Hanover
2 Hockamick Rd.
Cookstown, NJ 08511

Clerk, Borough of New Providence
360 Elkwood Avenue
New Providence, NJ 07974-1844

Clerk, Town of Newton
39 Trinity Street
Newton, NJ 07860

Clerk, Township of North Hanover
Municipal Building
41 Schoolhouse Road
Jacobstown, NJ 08562

Clerk, Township of Ocean
Township Hall
399 Monmouth Road
Oakhurst, NJ 07755-1589

Clerk, Township of Ocean
50 Railroad Avenue
Waretown, NJ 08758

Clerk, Borough of Ocean Gate
801 Ocean Gate Avenue, CN-100
Ocean Gate, NJ 08740

Clerk, Borough of Oceanport
315 East Main Street
Oceanport, NJ 07757

Clerk, Borough of Ogdensburg
14 Highland Avenue
Ogdensburg, NJ 07439

Clerk, Township of Montville
Municipal Building
195 Changebridge Road
Montville, NJ 07045-9498

Clerk, Township of Morris
50 Woodland Avenue
PO Box 7603
Convent Station, NJ 07961-7603

List of Municipal Clerks

Clerk, Borough of Morris Plains
531 Speedwell Avenue
Morris Plains, NJ 07950

Clerk, Town of Morristown
200 South Street, CN-914
Morristown, NJ 07963-0914

Clerk, Borough of Mt. Arlington
419 Howard Blvd.
Mt. Arlington, NJ 07856-1129

Clerk, Township of Mount Olive
Municipal Building
204 Flanders-Drakestown Road
PO Box 450
Budd Lake, NJ 07828

Clerk, Borough of Mountain Lakes
400 Boulevard
Mountain Lakes, NJ 07046

Clerk, Borough of Mountainside
Municipal Building
1385 Route 22
Mountainside, NJ 07092

Clerk, Township of Neptune
25 Neptune Blvd – PO Box 1125
Neptune, NJ 07753-1125

Clerk, Borough of Neptune City
106 W. Sylvania Avenue
Neptune City, NJ 07753

Clerk, Township of Old Bridge
One Old Bridge Plaza
Old Bridge, NJ 08857

Clerk, Township of Oxford
Municipal Building
11 Green Street, PO Box 119
Oxford, NJJ 07863

Clerk, Township of Parsippany-Troy Hills
1001 Parsippany Boulevard
Parsippany, NJ 07054

Clerk, Township of Long Hill
915 Valley Road
Long Hill, NJ 07933

Clerk, Boroughs of Peapack & Gladstone
1 School Street, PO Box 218
Peapack, NJ 07977

Clerk, Borough of Pemberton
Municipal Building
50 Egbert Street
Pemberton, NJ 08068-0261

Clerk, Township of Pemberton
500 Pemberton-Browns Mills Road
Pemberton, NJ 08068-1539

Clerk, Township of Pequannock
530 Newark-Pompton Turnpike
Pompton Plains, NJ 07444

Clerk, Town of Phillipsburg
Municipal Building
120 Filmore Street
Phillipsburg, NJ 08865

Clerk, Borough of Pine Beach
599 Pennsylvania Avenue
PO Box 425
Pine Beach, NJ 08741-0425

Clerk, Township of Plumsted
121 Evergeen Road
New Egypt, NJ 08533

Clerk, Township of Pohatcong
50 Municipal Drive
Phillipsburg, NJ 08865

Clerk, Borough of Point Pleasant
2233 Bridge Avenue - PO Box 25
Point Pleasant, NJ 08742

Clerk, Borough of Pt. Pleasant Beach
416 New Jersey Avenue
Pt. Pleasant Beach, NJ 08742

Clerk, Borough of Pompton Lakes
Municipal Building – 25 Lenox Avenue
Pompton Lake, NJ 07442

Clerk, Borough of Raritan
22 First Street
Raritan, NJ 08869

Clerk, Township of Raritan
One Municipal Drive
Flemington, NJ 08822-3446

Clerk, Township of Randolph
Municipal Building
502 Millbrook Avenue
Randolph, NJ 07869

Clerk, Borough of Ringwood
Borough Hall
60 Margaret King Avenue
Ringwood, NJ 07456

Clerk, Borough of Riverdale
91 Newark Pompton Turnpike
Riverdale, NJ 07457

Clerk, Township of Readington
Municipal Building
509 Rte. 523
Whitehouse Station, NJ 08889

Clerk, Borough of Red Bank
90 Monmouth Street
Red Bank, NJ 07701

List of Municipal Clerks

Clerk, Borough of Rockaway
Municipal Building
1 East Main Street
Rockaway, NJ 07866

Clerk, Township of Rockaway
65 Mt. Hope Road
Rockaway, NJ 07866-1698

Clerk, Borough of Roosevelt
Borough Hall - 33 N. Richdale Avenue
PO Box 128
Roosevelt, NJ 08555-0128

Clerk, Township of Roxbury
1715 Rte. 46
Ledgewood, NJ 07852

Clerk, Borough of Rumson
Memorial Borough Hall
80 E. River Rd.
Rumson, NJ 07760

Clerk, Sandyston Township
133 Route 645
Branchville, NJ 07826

Clerk, Borough of Sayreville
167 Main Street
Sayreville, NJ 08872

Clerk, Borough of Sea Bright
1167 Ocean Avenue
Sea Bright, NJ 07760

Clerk, Borough of Sea Girt
321 Baltimore Blvd. PO Box 296
Sea Girt, NJ 08750

Clerk, Seaside Heights Borough
901 Boulevard
Seaside Heights, NJ 08751

Clerk, Borough of Seaside Park
1701 N. Ocean Avenue
PO Box B
Seaside Park, NJ 08752

Clerk, Borough of Shrewsbury
419 Sycamore Avenue
PO Box 7420
Shrewsbury, NJ 07702-7420

Clerk, Township of Shrewsbury
1979 Crawford Street
Shrewsbury, NJ 07724

Clerk, City of South Amboy City
Hall, 140 N. Broadway Street
South Amboy, NJ 08879-1647

Clerk, Township of Southampton
Town Hall
5 Retreat Road
Southampton, NJ 08088

Clerk , Borough of South Belmar
1740 Main Street
PO Box 569
Lake Como, NJ 07719-0569

Clerk, Borough of South Toms River
Borough Hall
19 Double Trouble Road
South Toms River, NJ 08757

Clerk, Township of Mendham
Township Hall - W. Main & Cherry Lane
PO Box 520
Brookside, NJ 07926

Clerk, Township of South Brunswick
Municipal Complex - 540 Ridge Road
PO Box 190
Monmouth Junction, NJ 08852-0190

Clerk, Borough of Spring Lake
423 Warren Avenue
P.O. Box 638
Spring Lake, NJ 07762-0638

Clerk, Township of Sparta
65 Main Street
Sparta, NJ 07871

Clerk, Borough of Spotswood
77 Summerhill Road
Spotswood, NJ 08884

Clerk, Township of Springfield
Municipal Building – 1st Floor
100 Mountain Avenue
Springfield, NJ 07081-1702

Clerk, Borough of Spring Lake Heights
555 Brighton Avenue
Spring Lake Heights, NJ 07762

Clerk, Township of Springfield
Municipal Building
2159 Jacksonville Road
PO Box 119
Jobstown, NJ 08041

Clerk, Borough of Stockton
Municipal Building
2 South Main Street,
PO Box M
Stockton, NJ 08559

Clerk, Borough of Stanhope
77 Main Street
Stanhope, NJ 07874

Clerk, Township of Stillwater
964 Stillwater Road
Newton, NJ 07860

Clerk, Township of Tewksbury
169 County Road 517
Califon, NJ 07830

Clerk, City of Summit
512 Springfield Avenue
Summit, NJ 07901-2667

List of Municipal Clerks

Clerk, Borough of Sussex
2 Main Street
Sussex, NJ 07461-2397

Clerk, Township of Union
140 Perryville Road
Hampton, NJ 08827

Clerk, Township of Vernon
Municipal Building
21 Church Street
PO Box 340
Vernon, NJ 07462

Clerk, Township of Walpack
16 Old Mine Road
Walpack, NJ 07881

Clerk, Township of Warren
Municipal Building
46 Mountain Blvd.
Warren, NJ 07059-5605

Clerk, Township of Washington
43 Schooley's Mountain Road
Long Valley, NJ 07853

Clerk, Township of Wayne
475 Valley Road
Wayne, NJ 07470

Clerk, Township of West Milford
1480 Union Valley Road
West Milford, NJ 07840-1303

Clerk, Township of White
555 County Road 519
Belvidere, NJ 07823

Clerk, Borough of Union Beach
Municipal Building
650 Poole Avenue
Union Beach, NJ 07735

Clerk, Borough of Victory Gardens
Municipal Building
337 S. Salem Street
Dover, NJ 07801

Clerk, Borough of Wanaque
579 Ringwood Avenue
Wanaque, NJ 07465

Clerk, Borough of Washington
100 Belvidere Avenue
Washington, NJ 07882-1426

Clerk, Township of Washington
Robbinsville Municipal Building
1 Washington Blvd. – 2nd Floor – Suite 6
Robbinsville, NJ 08691-1103

Clerk, Township of West Amwell
150 Rocktown-Lambertville Rd.
Lambertville, NJ 08530-3203

Clerk, Township of West Windsor
Municipal Building
271 Clarkville Rd., PO Box 38
West Windsor, NJ 08550

Clerk, Township of Woodland
Municipal Building
3943 County Road 563
PO Box 388
Chatsworth, NJ 08019

Clerk, Borough of Wrightstown
Borough Hall
21 Saylors Pond Road
Wrightstown, NJ 08562

Clerk, Borough of Tinton Falls
Municipal Building
556 Tinton Avenue
Tinton Falls, NJ 07724-3298

Clerk, Township of Upper Freehold
Municipal Building
314 County Rte. 539
Cream Ridge, NJ 08514

Clerk, Township of Wall
2700 Allaire Road
PO Box 1168
Wall, NJ 07719-1168

Clerk, Township of Wantage
Municipal Building
888 Rte. 23
Sussex, NJ 07461

Clerk, Township of Washington
211 Rt. 31 North
Washington, NJ 07882

Clerk, Borough of Watchung
Municipal Building
15 Mountain Blvd.
Watchung, NJ 07069-6399

Clerk, Borough of West Long Branch
965 Broadway
West Long Branch, NJ 07764

Clerk, Borough of Wharton
Municipal Building
10 Robert Street
Wharton, NJ 07885

Clerk, Borough of Lake Como
1740 Main Street
Lake Como, NJ 07719

List of County Freeholders

Burlington County Bd of Freeholders
County Office Bldg.
49 Rancocas Rd.
PO Box 6000
Mt. Holly, NJ 08060

Essex County Bd of Freeholders
Hall of Records
465 Dr. Martin Luther King, Jr. Blvd.
Newark, NJ 07102

Hunterdon County Bd of Freeholders
County Administration Bldg.
71 Main St.
Flemington, NJ 08822

Mercer County Bd of Freeholders
McDade Administration
640 S. Broad St.
PO Box 8068
Trenton, NJ 08650-0068

Middlesex County Bd of Freeholders
Administration Bldg.
JFK Square
PO Box 871
New Brunswick, NJ 08903

Monmouth County Bd of Freeholders
Hall of Records
One E. Main Street
Freehold, NJ 07728

Morris County Bd of Freeholders
Administration & Records Bldg.
Court St.
PO Box 900
Morristown, NJ 07963-0900

Ocean County Bd of Freeholders
Administration Bldg.
101 Hooper Ave.
PO Box 2191
Toms River, NJ 08754

Passaic County Bd of Freeholders
Administration Bldg.
401 Grand St., 2nd Flr., #223
Paterson, NJ 07505

Somerset County Bd of Freeholders
20 Grove St.
PO Box 3000
Somerville, NJ 08876

Sussex County Bd of Freeholders
Administrative Center
One Spring St.
Newton, NJ 07860

Union County Bd of Freeholders
Administration Bldg.
6th Floor
Elizabeth, NJ 07207

Warren County Bd of Freeholders
Dumont Administration Building
165 Rte. 519 S.
Belvidere, NJ 07823

List of County Executive Offices & Administrators

Burlington County Administrator
Municipal Bldg.
851 Old York Rd.
PO Box 340
Burlington, NJ 08016-0340

Burlington County Administrator
City Hall
525 High Street
Burlington, NJ 08016

Essex County Executive
Hall of Records
465 Dr. Martin Luther King, Jr. Blvd.
Newark, NJ 07102

Hunterdon County Administrator
County Administration Bldg.
71 Main St.
Flemington, NJ 08822

Mercer County Executive
McDade Administration
640 S. Broad St.
PO Box 8068
Trenton, NJ 08650-0068

Middlesex County Administrator
Administration Bldg.
JFK Square
PO Box 871
New Brunswick, NJ 08903

Monmouth County Administrator
Hall of Records
One E. Main Street
Freehold, NJ 07728

Morris County Administrator
Administration & Records Bldg.
Court St.
PO Box 900
Morristown, NJ 07963-0900

Ocean County Administrator
Administration Bldg.
101 Hooper Ave.
PO Box 2191
Toms River, NJ 08754

Passaic County Administrator
Administration Bldg.
401 Grand St.
317 Pennsylvania Avenue
Paterson, NJ 07505

Somerset County Administrator
20 Grove St.
PO Box 3000
Somerville, NJ 08876

Sussex County Administrator
Administrative Center
One Spring St.
Newton, NJ 07860

Union County Administrator
Administration Bldg.
6th Floor
Elizabeth, NJ 07207

Warren County Administrator
Dumont Administration Building
165 Rte. 519 S.
Belvidere, NJ 07823

JERSEY CENTRAL POWER & LIGHT COMPANY
Comparative Balance Sheet at
December 31, 2019, 2020 and 2021
ASSETS AND OTHER DEBITS

FERC Account		DECEMBER 31 2019	2020	2021
	UTILITY PLANT			
101-106	Utility plant	7,147,126,493	7,516,417,582	7,731,710,040
107	Construction Work in Progress	243,841,527	237,579,973	251,023,678
	Total Utility Plant	7,390,968,020	7,753,997,555	7,982,733,718
108,111	Less Accumulated Provision for Depreciation	2,193,788,005	2,222,576,209	2,282,762,965
	Net Utility Plant	5,197,180,015	5,531,421,346	5,699,970,753
120.1 - 120.4 and 120.6	Nuclear Fuel			
120.5	Accum. Provision for Amortization			
	Net Nuclear Fuel			
	Net Utility Plant	5,197,180,015	5,531,421,346	5,699,970,753
	OTHER PROPERTY AND INVESTMENTS			
121	Nonutility Property	18,034,911	18,035,333	18,035,333
122	(Less) Accum. Prov. For Deprec. And Amort.	15,891,539	15,898,977	15,906,450
123	Investment in Associated Companies	-	-	-
123.1	Investment in Subsidiary Companies	892,666	890,451	-
124	Other Investments	1,048	752	1,583
128	Special Funds	256,101,540	283,478	84,775
175	Long-Term Portion of Derivative Assets	11,224	-	-
	Total Other Property and Investments	259,149,850	3,311,037	2,215,241
	CURRENT AND ACCRUED ASSETS			
131	Cash	-	-	8,020
132-134	Special Deposits	269,941,752	283,463,176	283,529,301
135	Working Funds	1,300	1,300	1,300
136	Temporary Cash Investments	-	-	170,000,000
142	Customer Accounts Receivable	117,905,200	151,150,601	142,269,396
143	Other Accounts Receivable	32,681,347	29,895,353	33,748,497
144	(Less) Accum. Prov. For Uncollectible Accounts-Credit	3,968,306	20,199,605	25,827,216
145	Notes Receivable from Associated Companies	-	37,850,833	-
146	Accts. Receivable from Associated Companies	79,174,030	15,660,720	39,477,935
151	Fuel Stock	-	-	-
154	Plant Materials and Operating Supplies	-	-	-
165	Prepayments	25,368,289	26,170,192	25,873,619
171	Interest and Dividend Receivable	-	-	31,589
172	Rents Receivable	2,784,305	5,068,818	3,242,200
173	Accrued Utility Revenues	80,271,694	90,854,001	114,538,533
174	Miscellaneous Current and Accrued Assets	-	-	-
175	Derivative Instruments Assets	-	-	-
175	(Less) Long Term Portion of Derivative Instrument Assets	-	-	-
	Total Current and Accrued Assets	604,159,611	619,915,389	786,893,174
	DEFERRED DEBITS			
181	Unamortized Debt Expenses	7,038,741	5,910,523	9,068,500
182.1	Extraordinary Property Losses	-	-	-
182.2	Unrecovered Plant and Regulatory Study Costs	4,016,887	3,907,879	3,798,871
182.3	Other Regulatory Assets	685,875,416	835,466,280	689,959,524
183	Prelim. Survey and Investigation Charges	2,254,808	2,010,923	2,056,070
184	Clearing Accounts	191,011	33,091	1,765,362
185	Temporary Facilities	588,827	721,842	966,703
186	Miscellaneous Deferred Debits	1,815,752,095	1,819,075,608	1,818,208,651
188	Research, Devel. And Demonstration Expend.	42,510	42,510	42,510
189	Unamortized Loss on Reacquired Debt	4,519,534	3,642,157	2,764,778
190	Accumulated Deferred Income Taxes	946,426,983	866,332,277	816,074,846
	Total Deferred Debits	3,466,706,812	3,537,143,090	3,344,705,815
	TOTAL ASSETS	9,527,196,288	9,691,790,862	9,833,784,983

JERSEY CENTRAL POWER & LIGHT COMPANY
Comparative Balance Sheet at
December 31, 2019, 2020 and 2021
LIABILITIES AND OTHER CREDITS

FERC Account		DECEMBER 31 2019	2020	2021
	PROPRIETARY CAPITAL			
201	Common Stock Issued	136,284,470	136,284,470	136,284,470
204	Preferred Stock Issued	-	-	-
207	Premium on Capital Stock	2,665,143,901	2,665,505,519	2,665,882,044
208-211	Other Paid-In Capital	51,334,517	56,585,306	61,674,229
215, 215.1,216	Retained Earnings	715,180,021	852,666,292	1,049,533,396
216.1	Unappropriated Undistributed Subsidiary Earnings	(42,871)	(45,086)	(45,050)
219	Accumulated Other Comprehensive Income	(5,576,306)	(5,600,403)	(5,610,637)
	Total Proprietary Capital	3,562,323,732	3,705,396,098	3,907,718,452
	LONG-TERM DEBT			
221	Bonds			
223	Advances From Associated Companies			
224	Other Long-Term Debt	1,650,000,000	1,650,000,000	2,150,000,000
225	Unamortized Premium on Long-Term Debt	5,122,874	4,274,560	3,426,246
226	(Less) Unamortized Discount on Long-Term Debt	4,311,070	3,826,023	4,639,655
	Total Long-Term Debt	1,650,811,804	1,650,448,537	2,148,786,591
	OTHER NON-CURRENT LIABILITIES			
227	Obligations Under Capital Leases	73,448,851	69,504,380	62,473,145
228.2	Accumulated Provision for Injuries and Damages	4,556,331	5,000,550	6,364,322
228.3	Accumulated Provision for Pension and Benefits	249,527,392	277,495,510	154,957,351
	Long-Term Portion of Derivative Instrument Liabilities	-	-	-
230	Asset Retirement Obligation	180,982,559	6,011,221	6,335,162
	Total Noncurrent Liabilities	508,515,133	358,011,661	230,129,980
	CURRENT AND ACCRUED LIABILITIES			
231	Notes Payable	-	450,000,000	-
232	Accounts Payable	182,856,413	160,826,689	146,373,791
233	Notes Payable to Associated Companies	114,140,939	-	71,642,138
234	Accounts Payable to Associated Companies	4,819,842	5,282,828	987,909
235	Customer Deposits	48,508,305	42,996,324	37,026,239
236	Taxes Accrued	2,875,611	8,823,283	25,696,401
237	Interest Accrued	21,968,437	23,023,572	26,548,399
238	Dividends Declared	-	-	-
241	Tax Collections Payable	5,829,671	7,456,503	6,688,311
242	Misc Current and Accrued Liabilities	56,235,608	60,576,542	88,092,395
243	Obligations Under Capital Leases	8,221,544	12,583,763	7,999,567
244	Derivative Instrument Liabilities	-	-	-
	(Less) Long-Term Portion of Derivative Instruments-Hedges	-	-	-
	Total Current and Accrued Liabilities	445,456,370	771,569,504	411,055,150
	DEFERRED CREDITS			
252	Customer Advances for Construction	46,857,198	46,154,354	54,477,103
255	Accumulated Deferred Investment Tax Credits	1,654,949	1,523,750	1,392,551
253	Other Deferred Credits	579,126,337	578,367,882	578,417,254
254	Other Regulatory Liabilities	1,056,027,502	918,357,082	811,288,903
257	Unamortized Gain on Reacquired Debit	18,502	-	-
282	Accum. Deferred Income Taxes-Other Property	1,118,422,785	1,183,580,376	1,231,294,522
283	Accum. Deferred Income Taxes-Other	557,981,976	478,381,618	459,224,477
	Total Deferred Credits	3,360,089,249	3,206,365,062	3,136,094,810
	TOTAL LIABILITIES AND OTHER CREDITS	9,527,196,288	9,691,790,862	9,833,784,983

APPENDIX C

JERSEY CENTRAL POWER & LIGHT COMPANY
Comparative Income Statement at
For the Years 2019, 2020 and 2021

FERC Account		DECEMBER 31 2019	2020	2021
	UTILITY OPERATING INCOME			
400	Operating Revenues	1,819,359,776	1,767,146,543	1,811,088,364
	Operating Expenses:			
401	Operation Expenses	1,203,841,935	1,228,038,290	1,067,848,137
402	Maintenance Expenses	167,710,218	281,536,414	155,604,723
403	Depreciation Expenses	167,161,187	182,725,883	172,574,764
	Depreciation Expenses for Asset Retirement Costs (403.1)	82,159	82,159	82,159
404-405	Amortization and Depl. Of Utility Plant	9,193,205	10,472,336	11,299,336
406	Amortization of Utility Plant Acq. Adjustment	-	-	-
407.3	Regulatory Debits	92,563,881	30,777,092	157,275,996
407.4	(Less) Regulatory Credits	74,050,578	223,542,683	107,952,504
408.1	Taxes Other Than Income Taxes	10,925,531	12,333,955	11,728,825
409.1	Income Taxes Federal	10,779,066	(14,865,322)	5,289,088
409.1	Other	(47,380)	(2,287,717)	(9,525,634)
410.1	Provision for Deferred Income Taxes	324,847,432	507,526,576	422,915,747
411.1	(Less) Provision for Deferred Income Taxes-Cr	311,601,610	474,143,885	359,971,610
411.4	Investment Tax Credit Adj.- Net	(131,199)	(131,199)	(131,199)
411.1	Accretion Expense	9,027,856	9,238,991	369,078
	Total Utility Operating Expenses	1,610,301,703	1,547,760,890	1,527,406,906
	NET UTILITY OPERATING INCOME	209,058,073	219,385,653	283,681,458
	OTHER INCOME AND DEDUCTIONS			
	Other Income:			
415	Revenues from Merchandising, Jobbing and Contract Work	626,213	2,465,283	579,537
416	(Less) Costs and Expenses of Merch., Job and Contract Work	1,005,794	2,069,600	1,248,184
417	Revenues from Nonutility Operations	-	-	-
417.1	(less) Expenses of Nonutility Operations	223	-	66
418	Nonoperating Rental Income	(3,498)	(7,438)	(7,473)
418.1	Equity in Earnings of Subsidiary Companies	15,818	4,926	139
419	Interest and Dividend Income	4,950,565	5,316,821	6,377,937
419.1	Allowance for Other Funds Used During Construction	7,369,721	1,253,018	6,429,295
421	Misc. Nonoperating Income	1,302,648	1,555,107	844,889
421.1	Gain on Disposition of Property	6,703,305	10,990	109,854,093
	Total Other Income	19,958,755	8,529,107	122,830,167
	Other Income Deductions:			
421.2	Loss on Disposition of Property	1,046,036	2,521,427	457,242
426.1	Donations	215,126	187,254	218,130
426.2	Life Insurance	(1,230,557)	(1,387,745)	(1,116,298)
426.3	Penalties	43,956	47	199,604
426.4	Exp. For Certain Civic, Political & Related Activities	56,844	546,199	537,479
426.5	Other Deductions	841,258	(2,666,577)	10,115,583
	Total Other Income Deductions	972,663	(799,395)	10,411,740
	Taxes Applicable to Other Income and Deductions:			
408.2	Taxes Other Than Income Taxes			
409.2	Income Taxes - Federal	1,716,721	3,472,087	20,351,749
409.2	Income Taxes - Other	752,535	1,579,352	9,528,843
410.2	Provision for Deferred Income Taxes	2,063,291	182,006	35,152,184
411.2	(Less) Provision for Deferred Income Taxes - Cr.	169,181	2,056,193	36,342,095
411.5	Investment Tax Credit Adjustment - Net	-	-	-
	Total Taxes on Other Income and Deductions	4,363,366	3,177,252	28,690,681
	NET OTHER INCOME AND DEDUCTIONS	14,622,726	6,151,250	83,727,746
	INTEREST CHARGES			
427	Interest on Long-Term Debt	82,769,722	82,700,000	90,377,083
428	Amort. Of Debt Disc and Expense	1,571,078	1,613,702	1,907,437
428.1	Amortization of Loss on Reacquired Debt	1,074,120	877,378	877,378
429	(Less) Amort. Of Premium on Debt-Credit	761,126	848,314	848,314
429.1	(Less) Amortization of Gain on reacquired Debt-Credit	19,716	18,501	-
430	Interest on Debt to Assoc. Companies	2,519,686	1,444,124	350,271
431	Other Interest Expense	7,671,938	7,847,106	11,006,955
432	(Less) Allowance for Borrowed Funds Used During Construction-Cr.	4,810,368	5,562,648	3,128,746
	Net Interest Charges	90,015,334	88,052,847	100,542,064
	Income Before Extraordinary Items			
	NET INCOME	133,665,465	137,484,056	266,867,140

JERSEY CENTRAL POWER & LIGHT COMPANY
Comparative Balance Sheet at
December 31, 2021
ASSETS AND OTHER DEBITS

FERC Account		December 31, 2021
	UTILITY PLANT	
101-106	Utility plant	7,731,710,040
107	Construction Work in Progress	251,023,678
	Total Utility Plant	7,982,733,718
108,111	Less Accumulated Provision for Depreciation	2,282,762,965
	Net Utility Plant	5,699,970,753
120.1 - 120.4 and 120.6	Nuclear Fuel	
120.5	Accum. Provision for Amortization	0
	Net Nuclear Fuel	
	Net Utility Plant	5,699,970,753
	OTHER PROPERTY AND INVESTMENTS	
121	Nonutility Property	18,035,333
122	(Less) Accum. Prov. For Deprec. And Amort.	15,906,450
123	Investment in Associated Companies	-
123.1	Investment in Subsidiary companies	-
124	Other Investments	1,583
125-128	Special Funds	84,775
175	Long-Term Portion of Derivative Assets	-
	Total Other Property and Investments	2,215,241
	CURRENT AND ACCRUED ASSETS	
131	Cash	
132-134	Special Deposits	283,529,301
135	Working Funds	1,300
136	Temporary Cash Investments	170,000,000
142	Customer Accounts Receivable	142,269,396
143	Other Accounts Receivable	33,748,497
144	(Less) Accum. Prov. For Uncollectible Accounts	25,827,216
145	Notes Receivable from Associated Companies	-
146	Accts. Receivable from Associated companies	39,477,935
151	Fuel Stock	-
154	Plant Materials and Operating Supplies	-
165	Prepayments	25,873,619
171	Interest and Dividend Receivable	31,589
172	Rents Receivable	3,242,200
173	Accrued Utility Revenues	114,538,533
174	Miscellaneous Current and Accrued Assets	-
175	Derivative Instruments Assets	-
175	(Less) Long Term Portion of Derivative Instrument Assets	-
	Total Current and Accrued Assets	786,893,174
	DEFERRED DEBITS	
181	Unamortized Debt Expenses	9,068,500
182.1	Extraordinary Property Losses	-
182.2	Unrecovered Plant and Study Costs	3,798,871
182.3	Other Regulatory Assets	689,959,524
183	Prelim. Survey and Investigation Charges	2,056,070
184	Clearing Accounts	1,765,362
185	Temporary Facilities	966,703
186	Miscellaneous Deferred Debits	1,818,208,651
188	Research, Devel. And Demonstration Expend.	42,510
189	Unamortized Loss on Reacquired Debt	2,764,778
190	Accumulated Deferred Income Taxes	816,074,846
	Total Deferred Debits	3,344,705,815
	TOTAL ASSETS	9,833,784,983

JERSEY CENTRAL POWER & LIGHT COMPANY
Comparative Balance Sheet at
December 31, 2021
LIABILITIES AND OTHER CREDITS

FERC Account		December 31, 2021
	PROPRIETARY CAPITAL	
201	Common Stock	136,284,470
204	Preferred Stock Issued	-
207	Premium on Capital Stock	2,665,882,044
208-211	Other Paid-In Capital	61,674,229
215, 215.1,216	Retained Earnings	1,049,533,396
216.1	Unappropriated Undistributed Subsidiary Earnings	(45,050)
219	Accumulated Other Comprehensive Income	(5,610,637)
	Total Proprietary Capital	3,907,718,452
	LONG-TERM DEBT	
221	Bonds	
223	Advances From Associated Companies	
224	Other Long-Term Debt	2,150,000,000
225	Unamortized Premium on Long-Term Debt	3,426,246
226	(Less) Unamortized Discount on Long-Term Debt	4,639,655
	Total Long-Term Debt	2,148,786,591
	OTHER NON-CURRENT LIABILITES	
227	Obligations Under Capital Leases	62,473,145
228.2	Accumulated Provision for Injuries and Damages	6,364,322
228.3	Accumulated Provision for Pension and Benefits	154,957,351
	Long-Term Portion of Derivative Instrument Liabilities	-
230	Asset Retirement Obligation	6,335,162
	Total Noncurrent Liabilities	230,129,980
	CURRENT AND ACCRUED LIABILITIES	
231	Notes Payable	
232	Accounts Payable	146,373,791
233	Notes Payable to Associated Companies	71,642,138
234	Accounts Payable to Associated Companies	987,909
235	Customer Deposits	37,026,239
236	Taxes Accrued	25,696,401
237	Interest Accrued	26,548,399
238	Dividends Declared	-
241	Tax Collections Payable	6,688,311
242	Misc Current and Accrued Liabilities	88,092,395
243	Obligations Under Capital Leases	7,999,567
244	Derivative Instrument Liabilities	-
	(Less) Long-Term Portion of Derivative Instruments-Hedges	-
	Total Current and Accrued Liabilities	411,055,150
	DEFERRED CREDITS	
252	Customer Advances for Construction	54,477,103
255	Accumulated Deferred Investment Tax Credits	1,392,551
253	Other Deferred Credits	578,417,254
254	Other Regulatory Liabilities	811,288,903
257	Unamortized Gain on Reacquired Debit	-
282	Accum. Deferred Income Taxes-Other Property	1,231,294,522
283	Accum. Deferred Income Taxes-Other	459,224,477
	Total Deferred Credits	3,136,094,810
	TOTAL LIABILITIES AND OTHER CREDITS	9,833,784,983

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Appendix E

JERSEY CENTRAL POWER & LIGHT COMPANY

Statement of the Amount of Total Revenue Derived in Calendar Year 2021 From Intrastate Sales and Services at Current Rates

Line #	Description	FERC Form-1 Page	FERC Form-1 Line	Notes	2021
1	Total Electric Operating Revenues	300	27		$ 1,811,088,364
2	Exclude:Contra Revenue Amounts in FERC 445	300	7		$ (4,848,698)
3	Revised Total Electric Operating Revenues				$ 1,815,937,062
4	Exclude: Sales for Resale Revenues	300	11		$ 16,496,786
5	Revised Total Electric Operating Revenues				$ 1,799,440,276
6	Total Add Back: Intrastate Sales for Resales				$ 3,819,540
7	Total Intrastate Revenues				$ 1,803,259,816

JERSEY CENTRAL POWER & LIGHT COMPANY
Transactions with Associated (Affiliated) Companies
For the 12 Months Ended December 31, 2021

Appendix G

DESCRIPTION OF SERVICE	NAME OF AFFILIATED COMPANY	AMOUNT
Provide President & CEO Support	FirstEnergy Service Company	$ 2,841,692
Provide Transmission & Distribution Support	FirstEnergy Service Company	$ 33,509,493
Provide Compliance & Regulated Services Support	FirstEnergy Service Company	$ 2,373,104
Provide Customer Support	FirstEnergy Service Company	$ 19,444,709
Provide SVP & Chief Financial Officer	FirstEnergy Service Company	$ 232,418
Provide Information Technology Support	FirstEnergy Service Company	$ 19,334,689
Provide Supply Chain Support	FirstEnergy Service Company	$ 6,907,678
Provide Accounting & Tax Support	FirstEnergy Service Company	$ 13,744,676
Provide Treasury Support	FirstEnergy Service Company	$ 640,509
Provide Strategy, LT Planning & Business Performance Support	FirstEnergy Service Company	$ 908,660
Provide Risk Support	FirstEnergy Service Company	$ 1,336,213
Provide Internal Auditing Support	FirstEnergy Service Company	$ 562,296
Provide Legal Support	FirstEnergy Service Company	$ 4,627,859
Provide Rates & Regulatory Affairs Support	FirstEnergy Service Company	$ 2,587,010
Provide Corporate Affairs & Community Involvement Support	FirstEnergy Service Company	$ 309,317
Provide External Affairs Support	FirstEnergy Service Company	$ 673,134
Provide Ethics & Compliance Support	FirstEnergy Service Company	$ 337,560
Provide Human Resources & Corporate Services Support	FirstEnergy Service Company	$ 2,671,939
Provide Corporate Responsibility and Communications Support	FirstEnergy Service Company	$ 1,290,261
Inventory Carrying Charges on Service Company Assets	FirstEnergy Service Company	$ 4,768,375
Interest Expense - Regulated Money Pool	FirstEnergy Corp.	$ 350,271
Transmission Charge - TMI Unit 1	Mid-Atlantic Interstate Transmission, LLC	$ 1,998,563
Transmission Investment Power Pool Agreement	Mid-Atlantic Interstate Transmission, LLC	$ 1,762,524
Rent - Akron Control Facility	American Transmission Systems, Inc.	$ 1,634,248
Rent - Wadsworth Facility	American Transmission Systems, Inc.	$ 1,458,149
Rent - Center for Advanced Energy Technology (CAET)	American Transmission Systems, Inc.	$ 1,385,879
Rent - West Akron Campus	FE Properties Inc	$ 558,953
Rent -Bethel Warehouse	Metropolitan Edison Company	$ 269,755
Rent - Pottsville Pike building	Metropolitan Edison Company	$ 598,412
Rent - Fairmont Corporate Center	Monongahela Power Company	$ 781,418
Rent - Monongahela Power Headquarter Facility	Trans-Allegheny Interstate Line Company	$ 694,891
Rent - Greensburg Corporate Center	West Penn Power Company	$ 983,311
	Total	**$ 131,577,966**

Accommodation or Convenience Payments:		
Purchased Power		$ 750,467,701
Interest on Debt		$ 85,793,750
Taxes		$ 147,565,411
Payroll (JCP&L)		$ 197,635,946
Employee Benefits		$ 37,521,241
NJ Agent Payments (Clean Energy Payments)		$ 63,319,426
USF Payments		$ 42,997,577
Lease Payments		$ 8,136,041
Other Convenience Payments		$ 223,337,676
Total Accommodation or Convenience Payments		**$ 1,556,774,770**

Attachment A

JCP&L 2023 Base Rate Case – Proposed Procedural Schedule	
March 16, 2023	Case filed.
March 2023	Discovery commences and is on-going as noted below.[1]
April 2023	Transmitted to OAL
May 2023	Pre-Hearing Conference with Administrative Law Judge
TBD	Deadline for motions to intervene or participate
TBD	Deadline for response to motions to intervene or participate
June 2, 2023	JCP&L issues 9+3 Update
June 30, 2023	Deadline for issuing discovery on Company's Petition and Direct Testimony
July 15, 2023	1st Rate Suspension Period Ends
July 21, 2023	Deadline for issuing discovery on 9+3 Update
August 7, 2023	JCP&L issues 12+0 Update
Mid- to Late- August 2023	Virtual Public Hearings
August 18, 2023	Deadline for issuing discovery on 12+0 Update
Weeks of August 21 and 28	Settlement Discussions
September 8, 2023	Rate Counsel and Intervenor Testimony Due
September 22, 2023	Deadline to issue discovery on Rate Counsel and Intervenor Testimony
Week of October 9	Settlement Discussions
October 20, 2023	Rebuttal Testimony Due
November 1, 2023	Deadline for issuing discovery on Rebuttal Testimony
November 15, 2023	2nd Rate Suspension Period Ends

[1] Except as otherwise noted herein, discovery will be issued on a rolling bases, subject to prescribed deadlines, with responses due in accordance with N.J.A.C. 1:1-10.4.

November 16, 2023	Responses to discovery on Rebuttal Testimony Due
November 20 or 21, 2023	Settlement Discussions
Week of November 27, 2023	Evidentiary Hearings[2]
December 22, 2023	Initial Briefs Due
January 12, 2024	Reply Briefs Due
February 26, 2024	Initial Decision
March 11, 2024	Exceptions to Initial Decision
March 18, 2024	Replies to Exceptions to Initial Decision
March 29, 2024[3]	BPU Final Decision

[2] If permitted by the ALJ, the parties will have an opportunity to present oral surrebuttal and rejoinder testimony during the evidentiary hearings.
[3] Subject to BPU Agenda Meeting schedule for 2024.

EXHIBIT JC-2

BEFORE THE
NEW JERSEY BOARD OF PUBLIC UTILITIES

In the Matter of the Verified Petition of Jersey Central Power & Light Company for Review and Approval of Increases in, and Other Adjustments to, Its Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith

Direct Testimony of
Mark A. Mader

RE:
Overview and Requested Rate Relief, Amortization of Deferred Storm Expense, Revenue Normalization Adjustment, Consolidated Tax Adjustment, Street Lighting Tariff Changes, Contract Labor and Fuel Cost Adjustments, and Return on AMI Stranded Cost Regulatory Asset

I. INTRODUCTION AND BACKGROUND

Q. Please state your name and business address.

A. My name is Mark A. Mader, and my business address is 300 Madison Ave, Morristown, NJ 07960.

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

A. I am employed by FirstEnergy Service Company ("FESC"), and my title is Director, Rates and Regulatory Affairs for New Jersey. My time is devoted to rates and regulatory tasks performed for Jersey Central Power & Light Company ("JCP&L" or the "Company") under the jurisdiction of the New Jersey Board of Public Utilities ("Board" or "BPU"). My qualifications are set forth in detail in Appendix A to my testimony.

Q. Please briefly describe your educational and professional background.

A. I graduated from West Virginia University in 1986, where I earned a Bachelor of Science in Mechanical Engineering. I was employed by Allegheny Energy for approximately 25 years. There, I held the positions of: Director, Energy Procurement; Director, Asset Management; and Director, Load Management. Upon completion of the acquisition of Allegheny Energy, Inc. by FirstEnergy Corp. ("FirstEnergy"), I relocated to New Jersey in the position of Senior Advisor. In January 2012, I was promoted to my current position.

Q. Have you previously testified in BPU proceedings?

A. Yes, I testified on behalf of JCP&L in its most recent base rate case BPU Docket No. ER20020146 and in two prior New Jersey base rate cases, BPU Docket No. ER12111052

and BPU Docket No. ER16040383. I have also testified before the Public Utilities Commission of Ohio, the West Virginia Public Service Commission, the Virginia State Corporation Commission, the Pennsylvania Public Utility Commission.

Q. Please describe the purpose of your testimony.

A. In my testimony, I provide an overview of the Company and its request for rate relief required to cover its cost of service and provide an adequate return for investors. I discuss the basis of the Company's proposal to address recovery of its storm-related regulatory asset. I also sponsor an adjustment related to revenue normalization and the calculation of a consolidated tax adjustment as required by the Board in its regulations. I will discuss and support proposed changes to JCP&L's Street Lighting Tariffs. Finally, I sponsor adjustments to test year expense for contract labor and fuel cost adjustments and support a request to establish a return on the Advanced Metering Infrastructure ("AMI") Stranded Cost Regulatory Asset.

Q. Please explain how your testimony is organized.

A. My testimony is organized into twelve (12) sections:

I. Introduction and Background
II. Overview of Company and its Service Territory
III. Request for Rate Relief
IV. Overview of the Petition
V. Amortization of Deferred Storm Expense
VI. Revenue Normalization Adjustment
VII. Consolidated Tax Adjustment
VIII. Street Lighting Tariff Changes
IX. Contract Labor and Fuel Cost Adjustments
X. Return on AMI Stranded Cost Regulatory Asset
XI. Conclusion

Q. Please describe and summarize the content of your testimony.

A. My testimony is summarized as follows:

Request for Rate Relief: JCP&L is requesting a base rate increase of $184.95 million on an annual basis, which will result in an overall average increase in JCP&L rates of 6.8%. Even with the Company's proposed rate increase, JCP&L residential rates (RS) will continue to be the lowest compared to all other New Jersey regulated electric distribution companies. The Company has experienced increases in its operations & maintenance ("O&M") expense. Not all of the O&M increase is attributable to increased operating costs. First, the Company has included, in addition to test year expense, pro forma adjustments to expand its vegetation management programs ($11.6 million), offer two new low-income programs ($2.5 million) and capture employee salary and wage increases beyond the test year ($5.4 million). Also, as explained in the testimony of Tracy Ashton, resulting from a Federal Energy Regulatory Commission ("FERC") Audit recommendation, FirstEnergy was required to adjust its administrative & general ("A&G") capitalization rate, which shifted costs that previously had been treated as capital to O&M. The impact of the adjustment to the capitalization rate more aptly represents a shifting of costs, as opposed to new being new costs or new expenditures. Nonetheless, it does result in higher O&M expense in the test year.

One of the most significant cost increases for JCP&L that supports the requested rate relief is the need to recover JCP&L's deferred storm cost balance, which is $310.2 million as of December 31, 2022. At the current level of recovery, it will take more than 10 years to recover the deferred storm balance. This significant storm balance, together with base capital expenditures, expected deferred costs for the accelerated AMI deployment and the planned filing of an infrastructure investment plan ("IIP"), each represent significant cash commitments in the near-term that will continue to pressure

JCP&L's financial metrics. While JCP&L is sensitive to the inflationary impacts to its customers at this time, without relief to improve cash flows, JCP&L is likely facing a downgrade from its current Moody's A3 credit rating, as discussed in the testimony of Bill Wang at Exhibit JC-6.

Amortization of Deferred Storm Expense: The Company is requesting to increase recovery of its deferred storm balance by $30 million from $29 million to $59 million per year, which results in approximately a 5-year amortization period for its storm-related regulatory asset balance of $310.2 million (as of December 31, 2022). The Company proactively has taken steps to reduce its storm-related regulatory asset balance. With the approval of the BPU, the Company applied the net proceeds from the sales of its Yards Creek Pumped-Storage Generating Facility of $108.7 million and the deferred tax regulatory liability associated with the sale of JCP&L's interest in the Three Mile Island Unit 2 ("TMI-2") nuclear facility of $12.1 million to reduce the Company's existing deferred storm cost balance. Despite these significant efforts, the Company's storm-related regulatory asset balance on December 31, 2022, has continued to grow and exceeds the storm-related regulatory asset balance from the Company's 2020 base rate case, which was $305.7 million as of June 30, 2020. Lastly, due to the extended time periods the Company carries storm-related costs in the regulatory asset, the Company is requesting a carrying charge be applied to its deferred storm balance, net of tax, at the 7-year Constant Maturity Treasury rate plus 60 basis points, which, as of March 3, 2023, is 4.75% (4.15% + 60 bps), to be updated January 1st of each year. There is precedent for the application of such carrying costs in the treatment of prior significant storm balances for JCP&L, which is discussed more fully in testimony below.

Revenue Normalization Adjustment: JCP&L proposes a downward adjustment to test year revenues by $14,766,262 to account for the impacts of weather. Consistent with its long-standing practice, the BPU has approved a weather normalization adjustment in JCP&L's 2020, 2016 and 2012 base rate cases as well as prior base rate proceedings.

Consolidated Tax Adjustment: Using the methodology set forth in the Board's rules at N.J.A.C. 14:1-5.12(a), the result is ($964,275), which is a reduction to rate base.

Light Emitting Diode ("LED") Street Lighting Tariff Changes: JCP&L is proposing changes to its streetlight tariff to provide optional LED connected street lighting service (i.e., smart streetlights) to its customers. The Company is proposing to sunset the Sodium Vapor Street Lighting Service ("SVL"), due to a lack of availability and the cost of replacement equipment, after December 31, 2025. Also, JCP&L is proposing changes to its LED Tariff to provide optional LED connected street lighting service (i.e., smart streetlights) to its customers. This tariff provision provides for a negotiated contract street lighting service on an individual basis. Such contracts shall incorporate the terms and conditions of this tariff and may include additional terms and conditions regarding advanced functionality and associated equipment, including, but not limited to, controllers, dimming capabilities, sensors, or other network enabled functions.

Contract Labor and Fuel Cost Adjustments: There are certain of JCP&L's services contracts that are expiring, and, under FirstEnergy's enterprise-wide procurement process, these contracts will be competitively bid and negotiated sometime in 2023. The services contracts that are planned to be executed during the test year include: 1) traffic control; 2) underground locating; and 3) distribution wood pole inspections. For purposes of this filing, the contract price increases only reflect the annualized costs for the test year. The

Company expects that bidding and negotiation of these contracts will be completed mid-year 2023. To the extent this is accomplished, and new pricing is known, these adjustments will be modified to include the new pricing for 2024 in the Company's 12+0 update. With respect to transportation fuel, in order to stabilize costs, FirstEnergy has a program to hedge a portion of its transportation fuel costs. The adjustment for fuel prices adjusts test year expense to calendar year 2023 fuel costs.

Return on AMI Stranded Cost Regulatory Asset: JCP&L is requesting that the BPU establish a carrying charge on the AMI Stranded Cost Regulatory Asset. Because JCP&L has filed a base rate case prior to the end of deployment under its AMI Plan, there is a potential gap in recovery of financing costs on the existing meter cost included in the AMI Stranded Cost Regulatory Asset unless the BPU establishes a carrying charge on the Stranded Cost Regulatory Asset in this case. As permitted in paragraph 36 of its approved AMI Stipulation of Settlement (BPU Docket No. EO20080545), JCP&L may request a return on the balance be included in the Stranded Cost Regulatory Asset in a subsequent base rate case, which it has in this instance.

II. JCP&L OVERVIEW

Q. Please provide an overview of the Company.

A. JCP&L is comprised of a talented, diverse team that is committed and dedicated to providing our customers with safe and reliable electric service at affordable rates. Our Company is, and strives to be, a workplace that invites diversity. Through the Company's diversity, equity, and inclusion ("DEI") programs, JCP&L maintains a high-performing team and works to create a culture where differences are respected, teamwork is encouraged, and employees are valued, driven and empowered to do their best.

FirstEnergy has received numerous awards demonstrating its commitment to DEI. These include the 2022 Leading Disability Employer Seal by the National Organization on Disability, ranking in *Minority Engineer* magazine's Top 50 Diversity Employers list for 2023, Forbes' Best Employers for Diversity in 2020, DiversityInc's Top Utilities list in 2019, 2020 and 2021, recognition by the Bloomberg Gender-Equality Index for women's equality in the workplace in 2019, 2020 and 2021, and recognition by G.I. Jobs magazine as a Military Friendly employer every year since 2016.

Also, as part of its DEI efforts, the Company is committed to providing opportunities to small, women-owned, minority-owned, HUBZone, veteran-owned, and service-disabled veteran-owned businesses through its supplier diversity program. In 2020, FirstEnergy spent $482 million with diverse suppliers and earned the 2021 Regional Council Member Done Deals award from the Women's Business Enterprise Center – East (WBEC-East) for the $54.8 million spent with women-owned businesses certified by WBEC-East. Additionally, JCP&L participates in the FirstEnergy Preferred Supplier Program, which seeks to support minority businesses within the FirstEnergy footprint using a three-pronged approach:

1. Enrollment – Suppliers identified by FirstEnergy will be given the opportunity to grow their existing relationship and possibly be used as a supplier.
2. Support – FirstEnergy will assist suppliers enrolled in the program through mentorship and training.
3. Investment – FirstEnergy will invest in minority-owned funds that are willing and able to invest in diverse businesses across our service territory.

JCP&L's employees take pride in supporting their local communities. The FirstEnergy Foundation and JCP&L have donated nearly $2 million over the last decade to New Jersey United Way agencies and raised more than $208,000 and 180,000 pounds of

food for New Jersey based food banks through Harvest for Hunger, an annual awareness campaign aimed at fighting hunger.

JCP&L continues to be listed on the New Jersey Sustainable Business Registry for its focus on environmental awareness and sustainable policy building and practices. Some of the Company's environmental stewardship efforts include establishing a Green Team to promote sustainable practices, implementing a program to repurpose older utility poles, and wildlife relocation and protection programs. As part of being named to the Sustainable Business Registry, in 2021, JCP&L was awarded the Certificate of Innovation in Sustainability by the New Jersey Department of Environmental Protection. Additionally, in 2021, JCP&L was recognized with the Environmental Leadership Award for Recycling/Pollution Prevention Programs by The Commerce & Industry Association of New Jersey ("CIANJ") and Commerce Magazine. JCP&L was selected for the award for stewardship and leadership of the environment. JCP&L has also been named as a Tree Line USA Utility by the Arbor Day Foundation every year since 2018.

In 2020, JCP&L was recognized among "Companies That Care" by CIANJ/Commerce Magazine for its donation, made in conjunction with FirstEnergy Foundation, to Lake Riviera Middle School in Brick Township, New Jersey. The funds allowed the school to purchase a greenhouse that is being used to grow food for the school's culinary arts program as well as for donation to local food banks. In 2022, JCP&L was a recipient of the New Jersey Alliance For Action Leading Capital Construction Projects award for its collaboration with Atlantic Health System and eight other companies on the construction of a combined heat and power plant at Morristown Medical Center.

Over the past three years, FirstEnergy has received numerous awards for Emergency Recovery and Emergency Assistance from the Edison Electric Institute. Three of the awards over the past three years include efforts made by JCP&L for its recovery from an event or recovery assistance provided to another utility. In 2020, FirstEnergy received two Emergency Assistance Awards; one for its efforts to help Entergy with restoration efforts in Texas and Louisiana following Hurricane Laura, and the second for its efforts to help Florida Power & Light and Duke Energy with restoration efforts in Florida following Hurricane Eta. In 2021, FirstEnergy received an Emergency Recovery Award for its response to the remnants of Hurricane Ida that affected the New Jersey service territory.

JCP&L will have invested $794.2 million in capital projects from July 1, 2020 through June 30, 2023 to enhance electric system resiliency and reliability for customers, which includes capitalized storm costs, which does not include approximately $22 million of expenditures related to JCP&L's Reliability Plus Infrastructure Investment Program ("JCP&L Reliability Plus"). With respect to vegetation management, the actual expense was $18.6 million from July 2022 through December 2022 and the forecasted expense is $15.7 million for the period of January 2023 through June 2023. These amounts are targeted for additional enhancements, including trimming trees along 3,396 miles of power lines as part of routine O&M to reduce vegetation-related outages. By maintaining a sharp focus on enhancing service reliability, building a strong workforce and supporting the communities and environment, JCP&L sustains its commitment to its customers.

At the same time, the Company's investments reflect its support for the Governor and Board's clean energy objectives, as articulated in the Energy Master Plan. The

Company has launched its "EV Driven" charging incentive program, is actively engaged in the ongoing deployment of the aforementioned AMI network, and was recently awarded more than $700 million in transmission investments to support the State's offshore wind objectives. Providing the Company the opportunity to recover its prudently-incurred costs will allow it to continue to invest in support of a clean energy future.

The testimony accompanying the Company's filing addresses its very real financial needs in today's economic climate, despite its demonstrated successes, both within the context of the challenges that JCP&L faces in continuing to provide safe and reliable service to its customers, at the same time that it is making strides to increase transparency and accountability to regulators, customers, and its other stakeholders.

Q. Please highlight FirstEnergy's FE Forward initiative.

A. The FE Forward initiative is a comprehensive plan designed to improve the quality and reliability of the company's electric transmission and distribution systems, while also enhancing customer service and engagement. The initiative includes investments in infrastructure, technology, and customer-focused programs all aimed at delivering a more modern and effective energy experience for customers. The new five-state operating model and corresponding changes to organizational structure are designed to centralize decision-making and create greater consistency across the company. The model enables us to streamline efforts and make it easier for teams to develop and implement business solutions.

While lines of reporting have moved to departments within FESC, the positions have largely remained as they had existing in New Jersey. In fact, from a regional

perspective JCP&L has experienced an increase in employees of approximately an additional 62 employees since 2020.

The benefits of the FE Forward initiative include:

1. Enhanced productivity: The initiative includes improvements through system integration that puts advanced technology tools, such as mobile dashboards and remote access to asset management information, in the hands of frontline employees. FE Forward is focusing on improving the efficiency of capital projects and modernizing processes. Asset management tools will allow FirstEnergy to make better decisions regarding project management.

2. Enhanced customer service: FE Forward includes a number of programs and initiatives aimed at improving customer service and engagement. For example, the company has launched a new customer-focused website and mobile app, which make it easier for customers to manage their accounts, pay their bills, and report outages. FirstEnergy has also implemented new customer service technologies, such as chatbots and virtual assistants, which provide faster and more personalized support. In addition, approaches were identified to connect to low-income customers, resulting in an increase in enrollment in low-income programs.

3. Increased efficiency in supply chain: As part of the transformation, the Supply Chain group is updating its technology to become an easy to engage and data-driven function for FirstEnergy. For example, FirstEnergy is currently implementing new Source to Pay software to replace its current enterprise sourcing platform. The new technology will link our sourcing, contract lifecycle management, purchase requisition, purchase order creation, invoicing, and payments in one tool.

Stakeholders will become more confident in FirstEnergy's sourcing decisions and governance with the technology.

Q. Were there organizational changes at JCP&L that resulted from the FE Forward initiative?

A. As a result of the reorganization, JCP&L now has four operations directors, reporting directly to the Company President, each with responsibility for lines, substation, meter services, and fleet services within their designated geographic area. This means that each operations director has responsibility for approximately one quarter of JCP&L's service territory. This structure provides direct oversight for each of the areas and provides better operations flexibility, management, and coordination for each area, which is expected to have the effect of enhancing the customer experience through more localized focus and attention by operations management. Please refer to the testimony of Dennis Pavagadhi for more information regarding implementation of FE Forward at JCP&L.

Q. Are there any other organizational changes that you wish to highlight?

A. Yes. FirstEnergy has also created a new Ethics and Compliance organization. This organization is organized within FESC under the leadership of a new Chief Ethics and Compliance Officer, who reports directly to the Senior Vice President & Chief Legal Officer. This group is charged with responsibility to ensure strong compliance processes, that policy controls are in place, and with strengthening the channels for employees to report concerns and further maturing our processes to address concerns. Also, the Ethics and Compliance group functions to increase transparency and accountability with respect to FirstEnergy's political and public policy engagement. Respecting this function, FirstEnergy seeks continuous improvement in these activities by monitoring,

benchmarking and incorporating an independent assessment of our program. FirstEnergy employees share a responsibility to foster and contribute to a culture that places compliance, ethics and integrity at the forefront of everything FirstEnergy does. That responsibility requires that employees act with integrity and voice opinions and concerns whenever a situation does not conform to expectations or violates laws, rules or regulations.

Q. Please describe the Company's service territory.

A. JCP&L provides service to approximately 1.1 million customers. Based on the number of customers, our customer base is 88.5% residential, 11.1% commercial, 0.2% industrial and 0.2% lighting customers. JCP&L operates and maintains over 339 substations, 244 sub-transmission circuits and 1,162 primary distribution circuits. I defer to the Company's witness, Mr. Pavagadhi (Exhibit JC-5), regarding further details of the Company's distribution system, distribution operations and particular characteristics of our service territory.

III. REQUEST FOR RATE RELIEF

Q. Why is JCP&L filing a base rate case at this time?

A. JCP&L's last base rate case filing was three years ago, in 2020. Since 2012, JCP&L's level of capital investments and operating costs in New Jersey have necessitated base rate cases approximately every three to four years. JCP&L's total distribution capital expenditures from July 1, 2020 through June 30, 2023 will be $794.2 million, which includes capitalized storm costs. Presently, the Company's base rates are not sufficient for JCP&L to earn an appropriate rate of return on its rate base and to recover its annual O&M expense. In addition, the Stipulation resolving JCP&L's filing to establish Energy Efficiency and Peak Demand Reduction Programs, as approved by the BPU (Dkt. No.

EO20090620, et al.), includes a Lost Revenue Adjustment Mechanism ("LRAM") and requires that the Company file a base rate case no later than five years after the commencement of the approved EE&C Plan, i.e., by July 1, 2026. This filing satisfies that requirement.

Q. Is the Company requesting an increase in its base rates in this filing?

A. Yes. As discussed in the direct testimony and schedules of JCP&L witness Carol A. Pittavino (Exhibit JC-3), JCP&L requires a base rate increase of $184.95 million on an annual basis. This will result in a 6.8% overall average increase in JCP&L's rates.

Q. Based on the Company's proposed request, what will be the impact on the typical residential bill?

A. As Yongmei Peng (Exhibit JC-9) explains in further detail, the proposed rate increase and design results in an increase of $8.45 per month for the typical residential customer, on Rate Schedule RS using an average of 780 kWh/month, representing a 7.5% increase.

Q. Should the Company's proposed requests be approved, how will the Company's rates compare to the rates of New Jersey's other electric public utilities?

A. The Company's proposed rates will continue to compare extremely favorably to those of New Jersey's other electric utilities. Ms. Pittavino's direct testimony (Exhibit JC-3) provides an illustration and additional information regarding JCP&L's lower rates as compared to the rates of the other New Jersey electric utilities.

Q. How will the proposed rate increase bring value to JCP&L's customers?

A. JCP&L must attract capital at cost-effective rates to remain a financially strong company that can continue to invest in its distribution system. By authorizing the Company to earn a fair rate of return, the Board will allow the Company to maintain the stability and

profitability needed to attract investors and capital at cost-effective rates. As a result, the Company will then be well-positioned to continue its capital expenditures program, which will allow us to continue to meet our customers' and this Board's expectations for providing safe and reliable service. Moreover, since 2020, the Company's customers have enjoyed stable base rates that are, as indicated above, below those of the other New Jersey electric utilities. During the same time, JCP&L has also made, and continues to make, important investments in the electric distribution system to enhance service and reliability for its customers.

IV. OVERVIEW OF THE PETITION

Q. Please provide an overview of the base rate filing.

A. JCP&L's request for rate relief in this proceeding (the "Base Rate Filing") consists of the Company's Petition (the "Petition") for rate relief, and the direct testimonies and supporting schedules of the Company witnesses who will testify on behalf of the Company and provide supporting documentation and exhibits.

Q. Please identify the other witnesses who are filing testimony in support of JCP&L's Base Rate Filing.

A. I provide an overview of the Company and the request for rate relief required to cover cost of service and provide an adequate return for investors. Also, I present the basis of Company's request for the amortization and recovery of its deferred storm expense, an adjustment related to revenue normalization and provide the calculation of a consolidated tax adjustment as required by the Board's regulations at N.J.A.C. 14:1-5.12(a)(11). Further, I sponsor proposed changes to JCP&L's LED Street Lighting Tariff, Contract

Labor and Fuel Cost Adjustments, and request for a return on the AMI Stranded Cost Regulatory Asset. See Exhibit JC-2.

Carol A. Pittavino, Manager Rates and Regulatory Affairs – NJ, sponsors the Company's revenue requirements, as well as certain accounting and normalization adjustments related to test year expenses, regulatory assets and liabilities, depreciation, and rate base. See Exhibit JC-3.

Tracy Ashton, Assistant Controller, Corporate of FirstEnergy, and Controller, JCP&L, provides testimony regarding FESC services and associated accounting, including FirstEnergy's cost allocation process. She also sponsors JCP&L's annual pension and other post-employment benefits ("OPEB") expenses and an OPEB accounting adjustment. See Exhibit JC-4.

Dennis L. Pavagadhi, Director of Operations for JCP&L, describes JCP&L's distribution system, unique aspects of its service territory, its organizational structure, its capital investment programs and its operations and maintenance programs (including, its inspection and maintenance programs, vegetation management program and its storm recovery and restoration process) and related expenses in New Jersey that support safety, service quality and reliability. Also, Mr. Pavagadhi discusses changes to certain charges found in Appendix A of the Company's Tariff. See Exhibit JC-5.

Bill Wang, Assistant Treasurer for FirstEnergy and Treasurer for JCP&L, testifies to JCP&L's capital structure, embedded cost of long-term debt, and overall cost of capital. See Exhibit JC-6.

Dylan W. D'Ascendis, a Director at ScottMadden, Inc., provides expert testimony on the appropriate rate of return on common equity for JCP&L, given its risk position. See Exhibit JC-7.

Tim Lyons, a Partner at ScottMadden, sponsors JCP&L's Cost of Service Studies, including testimony and supporting studies: one study which complies with the BPU's cost of service methodology; and a second study, which is an alternative Cost of Service Study as proposed by the Company. See Exhibit JC-8. He also presents and sponsors the Company's Cash Working Capital study. See Exhibit JC-11.

Yongmei Peng, N.J. State Regulatory Analyst V, Rates & Regulatory Affairs, sponsors the proposed rate design and proposed modifications to the tariff and schedules, including associated adjustments. Ms. Peng's testimony also addresses proof of revenues and customer bill impacts resulting from the filing. See Exhibit JC-9.

John J. Spanos, President of Gannett-Fleming, provides testimony summarizing a depreciation study and proposing revised depreciation accrual rates for JCP&L. See Exhibit JC-10.

John Ahr, Advisor, Regulatory Compliance – Smart Meters, discusses the JCP&L AMI Program and the Company's progress toward O&M savings described in the AMI Program and sponsors the AMI pro forma Operations & Maintenance "O&M" expense savings for JCP&L. See Exhibit JC-12.

Ken Strah, Vice President, Customer Care for FESC, discusses recent changes made to provide enhanced customer service to JCP&L's customers, and explains in detail the two new programs proposed to support the Company's most vulnerable customers. See Exhibit JC-13.

V. AMORTIZATION OF DEFERRED STORM EXPENSE

Q. What is the Company's proposal to recover the storm-related regulatory asset balance?

A. The Company's request is to increase amortization and recovery of its $310.2M storm-related regulatory asset balance (as of December 31, 2022) by $30 million, from $29 million to $59 million per year, which approximates a 5-year amortization period.

Q. Why is the Company proposing to increase amortization and recovery of its storm-related regulatory asset balance?

A. As stated in the testimony of Dennis Pavagadhi, the Company plans to file a special investment program under the Infrastructure Investment and Recovery rules (N.J.A.C 14:3-2A) to accelerate certain distribution investments to enhance reliability and resiliency. The Company is requesting a shorter amortization and recovery period for its deferred storm balance to provide additional cash to support the funding of these distribution investments and reduce the level of required borrowings. This will enable these investments to be made sooner and alleviate further pressure on JCP&L's credit metrics. Lastly, it is very sensible to use the amounts recovered from customers for prior storm costs to fund these needed investments, as the resulting distribution projects will function to reduce damage and the time required for restoration in future weather events.

Q. With a shorter amortization and recovery period, without an adjustment to base rates at the end of the amortization period, wouldn't the result be a windfall for the Company?

A. No. Should the Company's deferred storm balance be extinguished, that is, reduced to $0 it its next base rate case, the Company would set aside any amounts over-collected to be

refunded to customers or held in reserve for future storms, at the direction of the Board. An alternative, and more appropriate, recovery mechanism would be to allow rider recovery of the storm-related regulatory asset balance, such as was the case with the Rider Storm Recovery Charge ("SRC"), which was approved at the conclusion of the "Storm Cost Proceeding" NJ BPU Docket No. AX13030196.

Q. Is base rate treatment for deferred storm expense the most effective recovery mechanism?

A. No. Base rate treatment is not the most appropriate recovery mechanism for significant expenses that may vary widely from year to year. Because of the magnitude and variability of JCP&L's storm expense, the recovery of storm costs is better suited for a clause (rider) mechanism. Rider treatment of deferred storm expense, such as JCP&L's previous SRC, would enable rates to be adjusted more frequently (annually), which would enable better matching of expense and recovery.

Q. Are there financial implications related to the large, deferred storm balance?

A. Yes. Company witness Bill Wang (Exhibit JC-6) highlights the pressure on JCP&L's credit metrics, primarily due to large deferrals associated with storm costs and large, accelerated capital investments such as AMI. Carrying large regulatory asset balances impacts cash flow and, therefore, cash flow metrics, such as Cash Flow From Operations ("CFO") to Debt. Further, while unrecovered, these funds are unavailable for investments in service improvements, such as reliability, resiliency, and storm hardening programs. When considering that the Board's past practice of recovering storm costs through base rates results in extended recovery periods of five years or more, it is especially impactful that carrying costs are not applied to the storm-related regulatory asset balance. There is

precedent for the application of carrying charges to storm costs. The Board approved separate, distribution base rate recovery of Hurricane Irene costs using a 6-year amortization period, with a carrying charge on the unamortized balance. The rate was set at the 7-year constant maturity Treasury rate, at the time, plus 60 basis points. In addition, the Company was granted the Rider SRC "Storm Recovery Charge" resulting from the Generic Storm Proceeding in BPU Docket NO. AX13030196 to recover the $247 million in deferred O&M costs from Superstorm Sandy over a 6-year period using a 7-year constant maturity Treasuries rate plus 60 basis points.

Q. Is the Company proposing a carrying charge for its deferred storm balance at this time?

A. Yes. The Company proposes that a carry charge be applied to its deferred storm balance, net of tax, at the 7-year Constant Maturity Treasury rate plus 60 basis points, which, as of March 3, 2023, was 4.75% (4.15% + 60 bps), to be updated January 1st of each year.

Q. Is the Company proposing any changes to its Storm Cost Deferral Mechanism in this case?

A. No. The Company requests to continue use of its Storm Cost Deferral Mechanism as described in paragraph 31 of the Stipulation resolving its 2020 base rates case (Docket No. ER20020146, et al.), as approved by the Board.

VI. REVENUE NORMALIZATION ADJUSTMENT

Q. Why is it necessary to adjust retail sales to reflect normal weather?

A. Weather variance impacts the opportunity for JCP&L to recover its operating costs and earn its allowed return on investment. Should rates be established on billing determinants

from a test year that reflected higher than average sales due to weather, the Company would not recover its test year costs during a year of more moderate weather. Likewise, should rates be established on billing determinants from a test year that reflects lower than average sales due to weather, the Company would over-recover its test year costs during a year of more moderate weather. Therefore, JCP&L has included an adjustment to remove the effects of abnormal weather on test year revenues to set rates based on average (or weather normalized) sales data, and thereby increase the probability that the Company will recover its test year costs and earn its allowed return, no more or no less.

Q. Is a weather-adjustment to retail sales a customary adjustment in an electric utility base rate case in New Jersey?

A. Yes. The Board's long-standing practice is to use weather-normalized sales in setting electric utility base rates. The BPU has approved a weather normalization adjustment in JCP&L's 2020, 2016 and 2012 base rate cases as well as prior base rate proceedings.

Q. How does JCP&L determine what portion of its actual retail sales are weather sensitive?

A. A mathematical relationship is developed for JCP&L's distribution system throughput and daily weather data using degree days. This mathematical relationship is determined through regression analysis using 5 years of daily degree-day ("DD") data and historical billed loads by customer. Customer-specific degree-day coefficients arising from the regression analysis were aggregated to the customer class level to develop class-specific coefficients. The output of the models is weather-sensitive load as a function of weather (nonlinear slopes in kWh/temperature) for each day. The daily kWh/temperature slopes from the regression analysis are then multiplied by the daily deviation of actual average

daily temperature from normal temperatures (20-year daily averages) to yield the total weather-related sales adjustment for JCP&L.

Q. From what reporting stations does JCP&L collect the weather data that is used to normalize its retail sales?

A. A weighted average of 75% of the weather data reported by the Newark weather station and 25% reported by the Atlantic City weather station is used for JCP&L.

Q. How are the results from the regression analysis used to weather-adjust retail sales for each customer class?

A. The class-level coefficients are applied to the daily temperature deviations to arrive at weather sensitive sales by customer class. The adjustments are applied to the actual monthly sales such that positive adjustments are added in cases of less than average monthly weather and negative adjustments are added in cases of greater than average monthly weather.

Q. Are there adjustments made for classes that generally are not weather sensitive?

A. No. Industrial and public street and highway lighting customers do not require weather normalization, as these customers are minimally or non-weather sensitive. Therefore, these classes receive no allocation of weather-sensitive sales.

Q. How is the adjustment to retail sales then converted to revenues?

A. The weather adjustments allocated to the residential and commercial classes are priced on an incremental basis per the appropriate tariff rate schedule, pricing the weather-sensitive sales according to the respective kWh rate block in which weather-sensitive sales have been adjusted.

Q. Were customer charges or other non-kWh charges adjusted for weather?

A. No. Weather does not impact monthly charges such as customer charges and outdoor lighting charges.

Q. What is the weather normalization adjustment to revenues that JCP&L is proposing?

A. JCP&L proposes to adjust test year revenues by ($14.8 million), the calculation of which is set forth in Schedule CAP-2, Adjustment No. 1 to the direct testimony of Carol A. Pittavino (Exhibit JC-3).

VII. CONSOLIDATED TAX ADJUSTMENT

Q. Have you performed a consolidated tax adjustment calculation in conjunction with this filing?

A. Schedule MAM-1 provides a consolidated tax adjustment calculation, using the methodology set forth in the Board's regulation at N.J.A.C. 14:1-5.12(a). The result of the calculation is a ($964,275) reduction to rate base.

VIII. STREET LIGHTING TARIFF CHANGES

Q. Other than the changes to the charges under the Street Lighting Tariffs, what other changes is JCP&L proposing as part of this filing?

A. JCP&L is proposing changes to its streetlight tariff to provide optional LED connected street lighting service (i.e., smart streetlights) to its customers. The Company is also proposing to sunset the Sodium Vapor Street Lighting Service ("SVL"), due to availability and cost of replacement equipment.

Q. What are the changes to the LED Street Lighting Tariff?

A. JCP&L is requesting to add to its LED Tariff a negotiated contract street lighting service on an individual basis. Such contracts will incorporate the terms and conditions of this tariff and may include additional terms and conditions regarding advanced functionality and associated equipment, including but not limited to: controllers; dimming capabilities; sensors; or other network enabled functions.

Q. Who will bear the additional cost of these advanced functions and features?

A. All costs of these advanced functionalities not covered under the LED Tariff will be borne by the contracting customer. This is an optional service and other customers will not subsidize services under the special contract.

Q. Please explain the reasons for the proposed changes.

A. JCP&L believes that there are features and benefits from connected lighting that may be desirable to certain JCP&L customers. LED streetlight dimming and brightness control according to a programmed schedule and/or motion sensing can increase aesthetics, safety, and energy efficiency. For example, LED streetlights may be brightened for safety during entrance and exit to entertainment and sporting events. Likewise, LED streetlights may be dimmed for customer aesthetics and to reduce light pollution, better preserving the natural night environment.

Q. Are there environmental benefits from the deployment of connected streetlights?

A. Yes. LED connected streetlights are environmentally friendly as they reduce energy consumption and therefore carbon dioxide emissions. Also, LED connected streetlights are dark sky compliant and effective at managing light pollution.

Q. Are there benefits for JCP&L as well?

A. From a utility perspective, connected street lighting is consistent with Distribution Grid of the Future concepts by proactively identifying device failures (i.e., reducing truck-rolls), contributing to more precise geographic information system ("GIS") locations and enabling more accurate billing and accounting records. Also, connected streetlights can be integrated into work management systems to reduce customer calls by eliminating the need for customers to report light outages.

Q. Will these special arrangements be filed with the BPU for approval?

A. Yes. Because the non-tariff portion of these services will be covered by special contract, JCP&L will file these contracts with the BPU for approval, unless and until the Company is otherwise directed by the BPU.

Q. What are the key changes to the Sodium Vapor Street Lighting Service ("SVL") Service Classification?

A. JCP&L proposes to restrict this service classification to begin the elimination of Service Classification SVL and restrict this tariff except for existing luminaires of customers receiving service and only for the specific premises and class of service of such customers as of the effective date of rates and charges resulting from this proceeding. Further, the Company proposes to cease installation of sodium vapor luminaires under this service classification after December 31, 2025, unless the Company is unable to reasonably purchase sodium vapor luminaires before that time.

Q. Please explain the reasons for the proposed changes.

A. Over the past six years, the market for streetlights has shifted from 20% LED and 80% SVL to more than 95% LED. Further, in the Company's observation, nearly all sodium vapor post top, decorative and specialty lights have been discontinued and are unavailable for purchase. The result has been a tightening of supply and an increase in costs to purchase new and maintain existing sodium vapor luminaires. With these developments, the Company believes it is prudent to plan to eliminate service under the SVL Service Classification, while giving customers a reasonable timeframe to plan for this change.

Q. Is the Company able to purchase new sodium vapor luminaires?

A. Yes, but most often not from the original equipment manufacturers. As the original equipment manufacturers have ceased production, secondary manufacturers have purchased the used molds and dies to continue to manufacture sodium vapor luminaires. However, in the Company's observation, these luminaires are of lesser quality and the Company has concerns regarding the long-term performance and maintenance of these luminaires due to moisture intrusion.

Q. Has the cost of sodium vapor luminaires increased with the curtailment of production?

A. Yes. To purchase new, sodium vapor cobra head luminaires, the Company has experienced price increases of approximately 10% to 15% per year for the last 7 years. To the extent the Company is able to purchase new sodium vapor luminaires, the Company is paying higher prices for replacement luminaires to maintain this service.

Q. Is the Company able to purchase replacement sodium vapor lamps (light bulbs)?

A. Yes. However, FirstEnergy Supply Chain reports that, in 2022, all but one major manufacturer of SVL lamps has stopped production. The last manufacturer is working down their remaining materials and will close that line by the third quarter of 2023. In the future, SVL lamps will be purchased exclusively from offshore sources.

Q. Does the Company believe the restricting and then eliminating the SVL Service Classification will present a hardship to these street lighting customers?

A. No. The proposed restriction and elimination of the SVL Service Classification is not unlike the restrictions placed on the Mercury Vapor Street Lighting Service ("MVL") in July 1982. With the passage of The Energy Policy Act of 2005 (42 USC § 13201 et seq.), the manufacture or import of Mercury Vapor ballasts were banned after January 1, 2008. Once the Company had depleted its inventory, any mercury vapor luminaires that required new ballasts were replaced with Sodium Vapor luminaries. The Company expects that similarly, upon failure and where replacement parts are not reasonably available to maintain sodium vapor luminaires, sodium vapor luminaires will be replaced with LED luminaires.

Q. In your previous answer you stated that "sodium vapor luminaires will be replaced with LED luminaires." Why doesn't the Company just use an LED lamp (light bulb) in the existing sodium vapor fixture?

A. Sodium vapor lamps require a ballast to operate. To install an LED lamp in a streetlight fixture with a ballast, the ballast must be removed or bypassed. Based on the labor cost to rewire the streetlight fixture and the age of most sodium vapor streetlight fixtures, in most

cases, it is more economical to remove the sodium vapor streetlight luminaire and install a new LED streetlight luminaire.

Q. By not converting all streetlights to LED at the same time, wouldn't this result in "striping" (i.e., streetlights of different color along the same roadway), which is an aesthetics issue for some customers?

A. Yes, it would. However, the same "striping" issue resulted from the replacement of mercury vapor luminaires (bluish light) with sodium vapor luminaires (yellowish light). The Company does not believe that the replacement of sodium vapor luminaires (yellowish light) with LED luminaires (generally, whiteish light) would result in greater contrast in street light color along a roadway than previously experienced with the conversion from mercury vapor to sodium vapor streetlights. Further, the universe of streetlights will become more uniform over time as sodium vapor streetlights continue to be replaced with LED streetlights. To the extent that municipalities wish to replace non-LED streetlights prior to failure to have uniformity in certain areas, there are provisions in the Company's tariff for LED conversion.

Q. What are the implications with respect to stranded costs associated with the replacement of Sodium vapor streetlights with LEDs?

A. JCP&L's current tariff for the LED Service Classification provides a replacement option whereby "[u]pon failure, which shall be determined in the Company's sole discretion, and at the Customer's direction, which direction shall be set forth in an LED Replacement Agreement, the Company will replace a non-LED streetlight luminaire with an LED streetlight luminaire." Therefore, upon execution of an LED Replacement Agreement by the street lighting customer and upon failure of the sodium vapor luminaire, JCP&L will

replace the failed luminaire with an LED luminaire and there will be no direct billing to the street lighting customer for stranded costs associated with the replacement. However, under the LED Service Classification, stranded costs associated with the replacement of non-LED streetlights with LED streetlights that are not due to failure of non-LED streetlights are directly billed to street lighting customers.

Q. The elimination of the MVL Service Classification occurred over many years. The elimination of the SVL Service Classification is proposed for December 31, 2025. Does this provide sufficient time for customers to transition?

A. Unfortunately, the restriction and elimination of the SVL Service Classification must occur more quickly due to the current and expected lack of availability and the cost of replacement luminaires and lamps. As the Company indicated, its ability to maintain service under the SVL Service Classification may be extinguished before December 31, 2025, should the availability and price of sodium vapor luminaires become unmanageable. Street lighting service will be available under the LED Service Classification for the replacement of the sodium vapor luminaires.

Q. Is the Company proposing any changes to the stranded cost payments under Tariff LED at this time?

A. No. While the number and net book value of the existing streetlights has changed since the 2020 base rate case, the Company prefers to wait for the conclusion of Staff's statewide stakeholder process before recalculating its stranded cost payments under its LED tariff, so that it may reflect the results of the stakeholder process in its update. Because the streetlight stranded cost payments are currently only an element of the Cost of Service for

the LED tariff customers, changes to the stranded cost payments may be made by updating Tariff LED outside of a base rate case.

IX. CONTRACT SERVICES AND FUEL COST ADJUSTMENTS

Q. What is the purpose of the contract labor and fuel cost adjustments?

A. There are certain of JCP&L's services contracts that are expiring, and, under FirstEnergy's procurement process, these contracts will be competitively bid and negotiated sometime in 2023. With respect to transportation fuel, with the purpose of stabilizing costs, FirstEnergy has a program to hedge a portion of its transportation fuel costs. The proposed adjustments to the test year expense are to reflect these known and measurable price adjustments.

Q. What services contracts does proposed Adjustment 23 address?

A. The services contracts that are planned to be executed during the test year include: 1) traffic control; 2) underground locating; and 3) distribution wood pole inspections. The contract for vegetation management services was also competitively bid during the test year; however, the adjustment for the new vegetation management contract is presented as part of Adjustment 12.

Q. With respect to these services contracts, what is FirstEnergy's procurement process?

A. For contract services that FirstEnergy or JCP&L requires on an ongoing basis, the contracts are competitively bid and renegotiated prior to the expiration of the existing contract to ensure continuity of services. FirstEnergy maintains a qualified vendor list, including diverse suppliers, that provide these services. FirstEnergy issues a request for proposals to the selected vendors, evaluates the responses, and selects a winning bidder. Criteria used to select the winning bidder includes, but is not limited to pricing, safety, supplier diversity

and capabilities and prior performance. Often, but not always, the lowest bidder is selected. Regarding these services, FirstEnergy contracts with multiple vendors to ensure that there are available and scalable resources available to the operating companies, including JCP&L.

Q. What services are provided under these contracts?

A. Traffic Control: Provides traffic control services where required by municipal, county, or state jurisdictions or to ensure safety of JCP&L workers when performing work on JCP&L facilities along a public roadway.

Underground Locating: Provides services to support the "NJ One Call" program, which is a state required program that benefits JCP&L customers. It is a no-cost service to locate underground utilities prior to performing excavation work. Both JCP&L and its customers benefit as the program is intended to prevent equipment damage to JCP&L facilities and the associated outages and to ensure public safety when working near the Company's underground facilities.

Distribution Wood Pole Inspections: Provides services to perform pole inspections to support JCP&L's pole inspection program to meet the requirements under § 14:3-2.7 - Inspection of Property and § 14:5-8.8 Annual System Performance Report.

Q. When do these services contracts expire?

A. The contracts for traffic control, underground locating and distribution wood pole inspections expire December 31, 2023.

Q. Given the expiry date of these services contracts, how will these price changes become known and measurable in a timeframe that enables them to be considered in this base rate case?

A. FirstEnergy plans to rebid these contracts and have revised pricing finalized in time to reflect in normalized expense any price changes in JCP&L's 12+0 (12-months actual data and 0-months forecast data) update to this base rate case filing. I will amend my testimony, as necessary and at that time, to discuss price changes and the impact on normalized test year expense.

Q. Why is JCP&L permitted to adjust test year expense for contract price changes beyond the test year?

A. The Board's long-standing practice regarding post-test year adjustments in base rate cases is based on its decision in *In re Elizabethtown Water Company*, BPU Docket No. WR8504330 (Order dated May 23, 1985), at 2 ("*Elizabethtown Water*"). According to the Board's *Elizabethtown Water* precedent, utilities are generally permitted to include in base rate requests known and measurable changes to O&M expense nine months beyond the test year. Because these contract price changes are known prior to the conclusion of the test year and these contract price changes are in effect within nine months of the test year, based on *Elizabethtown Water*, it is appropriate to make the proposed adjustments to test year expense to reflect the known changes in costs for these contract services.

Q. Since the new contract pricing will not be known until the Company files its 12+0 update to this filing, what did the Company use to adjust test year expense for these contract rate increases in this 6+6 (6-months actual data and 6-month forecast data) filing?

A. For purposes of this filing, the contract price increases only reflect the annualized costs for the test year. Each of these contracts provides for an annual price increase on January 1st of each year. The proposed adjustments are to reflect the impacts of the 2023 price increases on total test year expense. The Company expects that bidding and negotiation of these contracts will be completed mid-year 2023. To the extent this is accomplished and new pricing in known, these adjustments will be modified to include the new pricing for 2024 in the Company's 12+0 update.

Q. How does FirstEnergy determine that these prices reflect market prices for these services?

A. Services related to distribution pole inspections and traffic control are competitively sourced; therefore, the resulting pricing reflects the market price for these services. There are several vendors that provide these services and robust participation by a pool of vendors provides for effective price discovery. Due to consolidation in the industry, there are fewer vendors that offer underground locating services. As with underground locating, in cases where there may not be a robust response to a request for proposals, there are a limited number of service providers or otherwise as a general benchmark to ensure effective price discovery, FirstEnergy compares proposed labor cost increases against labor costs from the Bureau of Labor and Statistics for specific labor categories, to evaluate overall labor rate and labor cost increases.

Q. What is the proposed adjustment to test year expense and how is it calculated?

A. Proposed Adjustment 23 presents the adjustment for each contract separately for Traffic Control, Underground Locating and Pole Inspections. The adjustment to the test year expense totals $59,337 for these three contracts.

To calculate the Traffic Control Adjustment, the actual costs paid to each vendor for traffic control services from July-December 2022 were collected. The actual costs were allocated 85% to labor and 15% to equipment. A monthly average labor and equipment cost was then calculated. The monthly average labor costs were then divided by the average hourly rate for all employee classifications to get the estimated hours. For equipment, the hourly rate for patrol trucks was used to determine the estimated equipment hours. The labor and equipment hours for July-December 2022 were multiplied by the average employee classification rate and patrol truck rate, respectively, effective as of January 1, 2023. The calculated adjustment is then split between O&M and capital based on test year experience, which allocation factor will be updated in the 12+0 as the test year concludes. The adjustment to test year expense reflects the increase in cost from the 2022 activity repriced at 2023 contract rates, which amount is $12,783. *See* Schedule MAM-2.

To calculate the Underground Locating Adjustment, because data from the vendor for July-December was not yet available, a 3-year average of activity was used as a proxy for the number of underground locations performed from July-December 2022. This data will be updated with actuals in the 12+0 update to this filing. The count was then multiplied by the rate effective January 1, 2023. The calculated adjustment is then split between O&M and capital based on test year experience, which allocation factor will be updated in the 12+0 as the test year concludes. The adjustment to test year expense reflects the increase in cost from the 2022 activity repriced at 2023 rate, which amount is $40,047. *See* Schedule MAM-2.

To calculate the adjustment for Pole Inspections, data was gathered for pole inspections conducted from June-December 2022 by inspection type. The count was

adjusted to reflect 6 months of the test year and the count for each inspection type was then multiplied by the rate for that inspection effective January 1, 2023. The calculated adjustment is then split between O&M and capital based on test year experience, which allocation factor will be updated in the 12+0 as the test year concludes. The adjustment to test year expense reflects the increase in cost from the 2022 inspection activity repriced at 2023 inspection rates, which amount is $6,507. *See* Schedule MAM-2.

Therefore, each adjustment reflects the difference between the test year O&M expense and the test year units of work repriced at the 2023 contract prices. Because the current filing is based on 6+6, these adjustments will be updated to reflect actual service units for the test period in the 12+0 update. Also, as explained previously, the adjustment will be updated to reflect the 2024 contract prices, where known, in the 12+0 update to this filing.

Q. You stated earlier that FirstEnergy hedges its fuel expense to stabilize cost, how does FirstEnergy hedge its fuel costs?

A. FirstEnergy set its budget and targets to purchase about 60% of its fuel for the following year using forward contracts. The objective of the hedging program is to stabilize fuel prices for planning and budgeting purposes. By purchasing only a portion of the required fuel supply forward, FirstEnergy may still benefit from positive market movements (i.e., lower fuel prices) and is protected to some degree against negative market movements (i.e., higher fuel prices). For example, should market prices for fuel move downward, the spot market purchases of the unhedged fuel quantity function to lower average fuel cost for the year, creating a positive budget variance. Should market prices for fuel move upward, the Company has fewer adjustments to make to other operating expenses to meet its budget.

For purposes of fuel expense, the cost of the forward contracts and market purchases for the unhedged quantities is the amount reflected in fuel expense.

Q. Is JCP&L allocated costs associated with hedging activity and are these costs recovered from customers?

A. There are no hedging costs that are allocated to JCP&L. Fuel costs charged to JCP&L are based on its fuel consumption and based on the cost of fuel purchased, which is an average cost of the forward contract for the hedged quantities and spot market purchases for the unhedged quantities.

Q. What has been FirstEnergy's experience with its hedging program for fuel prices?

A. Customers benefit from this program because greater fuel cost stability over the long-term translates to greater rate stability for customers. During the second half of 2022, JCP&L's fuel cost was lower than monthly spot market prices, capital and O&M, by $526,092 or 40% and is projected to save $672,294 or 28% as compared to monthly spot market prices during the test period as a result of FirstEnergy's fuel hedging program.[1] However, while the fuel hedging program may result in fuel cost savings when compared to spot market prices, the approach is to stabilize fuel prices and, therefore, may not always result in lower fuel cost.

Q. What is the proposed adjustment to test year expense and how is it calculated?

A. The proposed adjustment to test year fuel expense is $22,123. *See* Schedule MAM-2. Adjustment 23 represents the adjustment to test year fuel expense to reflect calendar year

[1] If requested in discovery, workpapers for these calculations will be provided pursuant to a non-disclosure agreement. The underlying data is commercially-sensitive and confidential.

2023 for both the hedged and unhedged portion of JCP&L's fuel cost. Where there are fuel quantities for this period that have not yet been hedged, the forward prices for deliveries during that period are used. To calculate this adjustment, the Company quantified the total amount of fuel consumed or forecasted to be consumed during the test year and then multiplied these quantities by the hedged or forward prices, as applicable, to calculate test year fuel expense. The Company then performed the same calculation for calendar year 2023. The adjustment to test year fuel expense is the difference between the 2023 calendar year fuel expense and the test year fuel expense. The fuel cost increase is then split between O&M and capital based on the ratio of test year capital and O&M labor costs. Because the current filing is based on 6+6 (6 months actual data and 6 months forecasted data), this adjustment will be updated to reflect actual fuel consumption for the test period in the 12+0 update. Also, this adjustment will be updated to reflect the hedged and unhedged fuel prices for the remainder of calendar year 2023 in the 12+0 update to this filing.

Q. Why is the ratio of test year capital and O&M labor-hours used to allocate fuel costs for purpose of this adjustment?

A. FirstEnergy charges costs associated with its vehicle fleet using a transportation overhead. Costs such as vehicle repairs, maintenance, lease costs and fuel are cleared through this transportation overhead. Hourly vehicle rates are developed by vehicle class and vehicle costs are charged to capital and O&M projects through this transportation overhead. FirstEnergy does not directly track vehicle use or fuel consumption between capital and O&M projects.

For purposes of this adjustment, JCP&L used timesheet reporting for those field employees that use a vehicle as part of their job responsibilities as a proxy to allocate fuel costs between capital and O&M. Timesheet charges reflect labor-hours charged to capital and O&M. For employees who use a vehicle as part of their job responsibilities, vehicle-hours will follow labor hours reported on their timesheets. Therefore, the use of timesheets as a proxy to allocate fuel costs between capital and O&M is reasonable.

Q. Why is JCP&L permitted to adjust test year expense for fuel expenses beyond of the test year?

A. As discussed previously, under the Board's *Elizabethtown Water* precedent, utilities are generally permitted to include in base rate requests known and measurable changes to O&M expense nine months beyond the test year. Because the hedged fuel prices for the hedged quantity of fuel for calendar year 2023 are known prior to the conclusion of the test year and the costs resulting from hedged fuel prices occur within nine months of the test year, based on *Elizabethtown Water* it is appropriate to make the proposed adjustment to test year expense to reflect the changes in fuel costs.

X. RETURN ON AMI STRANDED COST REGULATORY ASSET

Q. Why is JCP&L replacing customer electric meters with AMI meters?

A. On February 19, 2020, the BPU issued an Order in BPU Docket No. ER16060534 ("AMI Filing Order") requiring JCP&L and other New Jersey electric distribution utilities to file a petition "for AMI implementation", or update a previously filed petition, by August 27, 2020.

Q. **Can you briefly describe JCP&L's compliance plan?**

A. The Company's AMI Plan was approved by the BPU on February 29, 2020, which details the implementation plan for the accelerated deployment of approximately 1.15 million AMI meters across JCP&L's service territory. Implementation will be in three phases: Pre-deployment Phase; Deployment Phase; and Final Engineering Phase. The AMI Plan began in 2022 and will end in 2027, with 99% of the meters being installed from 2023 to 2025. The estimated costs for the AMI Plan are $390 million in capital investment, $73.3 million in O&M and $30.8 million in Cost of Removal.

Q. Does the BPU's order in its AMI proceeding authorize JCP&L to defer AMI stranded costs?

A. Yes. JCP&L's approved stipulation in this matter provides in paragraph 28:

> "…AMI Plan-related capital costs and legacy meter stranded costs shall be deferred and placed in regulatory assets, as separate and identifiable accounts, for recovery of the regulatory assets deemed prudent in the Company's subsequent base rate cases…"

Q. Is the Company requesting recovery of the AMI Stranded Costs to date in this proceeding?

A. No. Stranded Costs are not to be recovered prior to the end of the Deployment Phase, which is planned for December 31, 2025. Paragraph 36 of JCP&L's approved stipulation states as follows:

> The recovery of the Stranded Cost Regulatory Asset shall be excluded from cost recovery until the subsequent base rate case associated with full deployment of AMI (full deployment occurs at the conclusion of the Company's Deployment Phase as defined in paragraph 25), if deemed reasonable and prudent.

Q. What is the Company requesting with respect to the AMI Stranded Cost Regulatory Asset in this case?

A. JCP&L requests that the BPU establish a carrying charge on the AMI Stranded Cost Regulatory Asset.

Q. If the Company has stipulated that recovery of the AMI Stranded Cost Regulatory Asset is not to be determined until after full deployment, then why must the BPU establish a carrying charge on the AMI Stranded Cost Regulatory Asset at this time?

A. Again, to be clear, the Company is not asking to begin recovery of the AMI Stranded Cost Regulatory Asset. However, it is necessary for the BPU to establish the carrying charge on the AMI Stranded Cost Regulatory Asset in this case to avoid a potential gap in recovery, where the Company receives no carrying charge on the stranded costs (associated with existing meters removed from service) from the conclusion of this base rate case until such time that the BPU addresses recovery of the AMI Stranded Cost Regulatory Asset after full deployment.

Q. What gives rise to this potential gap in recovery?

A. Simply, filing a base rate case before the end of full deployment.

Q. What are you referring to as a "potential gap in recovery" in your previous response?

A. The existing legacy meters are currently included in the JCP&L's distribution rate base where the Company recovers its rate base costs at its weighted-average cost of capital on this investment, just as it does for all other elements of its rate base investment as well. Over the duration of the AMI Plan, existing meters will be removed from service and the stranded cost associated with the existing meters removed from service will be placed in

the AMI Stranded Cost Regulatory Asset. Until JCP&L files a base rate case and base rates are reset, JCP&L will continue to recover its rate base costs associated with the existing meters.

However, should JCP&L file a base rate case prior to the end of full deployment, as it has done in this instance, upon conclusion of this base rate case, when base rates are reset, the stranded cost associated with the existing meters that have been included in the AMI Stranded Cost Regulatory Asset will no longer be included in rate base. Because the BPU has not yet established a carrying charge to be applied to the AMI Stranded Cost Regulatory Asset, until the BPU establishes a carrying charge, the Company will no longer recover its financing costs on the existing meter cost included in the AMI Stranded Cost Regulatory Asset until a subsequent base rate case associated with full deployment of AMI.

Q. Did JCP&L address this potential gap in recovery in its stipulation?

A. Yes. Recognizing that JCP&L's AMI Plan spanned a longer period and that it was likely that the Company would file a base rate case in the interim, there was language included in its stipulation to address this potential gap in recovery. Paragraph 36 provides:

> "With respect to the return on the Stranded Cost Regulatory Asset, the Signatory Parties agree the Company may request a return on the balance be included in the Stranded Cost Regulatory Asset in a subsequent base rate case, to permit this issue to be considered at that time. Notwithstanding anything in this paragraph, the Signatory Parties may take whatever positions they desire regarding a return on the Stranded Cost Regulatory Asset at that time."

Q. What is the carrying charge that the Company is requesting to be applied to the AMI Stranded Cost Regulatory Asset?

A. The Company requests that the carrying charge be set at its weighted average cost of capital established in this case at least until recovery of the AMI Stranded Cost Regulatory Asset

is fully addressed in a subsequent base rate case associated with full deployment of AMI. JCP&L's weighted-average cost of capital reflects its financing costs for utility assets in rate base, such as meters.

Q. Why does the Company believe that its weighted average cost of capital is a just and reasonable carrying charge during this period?

A. By setting the carrying charge at the weighted average cost of capital at this time, rate recovery with respect to the stranded cost associated with the existing meters removed from service would be the same as it would have been throughout AMI deployment, as though JCP&L had not filed an interim base rate case. It would place JCP&L on equal footing with other EDCs that do not file base rate cases during deployment, with respect to the treatment of Stranded Costs.

XI. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

JERSEY CENTRAL POWER & LIGHT

Consolidated Tax Adjustment
BPU Methodology under N.J.A.C 14:1-5.12(a)(11) - Five Years of Data, 100% Sharing, Distribution Only

YEAR	Utility Taxable Income/(Loss)	Total Affiliate Taxable Losses	Statutory Tax Rate	Tax on Cumulative Losses Before AMT	AMT	Total Net Tax on Losses
2017	219,631,235	(848,942,825)	35.00%	(297,129,989)	11,721,807	(285,408,182)
2018	(234,326,028)	(963,981,549)	21.00%	(202,436,125)		(202,436,125)
2019	42,554,053	(738,755,936)	21.00%	(155,138,747)		(155,138,747)
2020	(140,309,365)	(6,761,930,525)	21.00%	(1,420,005,410)		(1,420,005,410)
2021	115,665,976	(523,697,591)	21.00%	(109,976,494)		(109,976,494)
TOTAL	3,215,871	(9,837,308,427)		(2,184,686,765)		(2,172,964,958)

Utility Percentage of Net Gain	0.06%
Sharing Percentage	100%
Distribution Percentage	73.96%
CTA Rate Base Adjustment	**(964,275)**

JERSEY CENTRAL POWER & LIGHT COMPANY

Adjustment for Contract Labor & Fuel Costs

	Adjustment	Capitalization %	O&M Adjustment
Traffic Control	$ 63,915	80.00%	$ 12,783
Underground Locating	41,286	3.00%	40,047
Pole Inspections	6,507	0.00%	6,507
Transportation Fuel	53,258	58.46%	22,123
Adjustment Amount	**$ 164,966**		**$ 81,460**

EXHIBIT JC-3

BEFORE THE
NEW JERSEY BOARD OF PUBLIC UTILITIES

In the Matter of the Verified Petition of Jersey Central Power & Light Company for Review and Approval of Increases in, and Other Adjustments to, Its Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith

Direct Testimony
of
Carol A. Pittavino

RE: Revenue Requirements

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Carol A. Pittavino. My business address is 800 Cabin Hill Drive, Greensburg, PA 15601.

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

A. I am employed by FirstEnergy Service Company ("FESC") in the Rates & Regulatory Affairs Department for Jersey Central Power & Light Company ("JCP&L" or "Company").

Q. Please describe your professional experience and educational background.

A. I am employed by FESC, and my title is Manager in the New Jersey Rates & Regulatory Affairs Department for JCP&L. I report to Mark A. Mader, New Jersey Director of Rates & Regulatory Affairs. My principal responsibilities are to provide financial and analytical support for JCP&L.

Q. Please briefly describe your educational and professional background.

A. I graduated from Seton Hill University (then College) in May 2000 with a Bachelor of Science degree with a major in accounting. I earned my Pennsylvania Certified Public Accountant license in September 2003.

In August 2012, I was employed by JCP&L as a rates analyst. From November 2017 to January 2019, I held an Analyst position in the FirstEnergy Transmission Business Services area, while continuing to support Rates and Regulatory Affairs. In January 2019, I returned to JCP&L Rates and Regulatory Affairs.

From October 2003 to September 2010, I was employed by Allegheny Energy, Inc. as a Senior Accountant in the Regulatory Accounting department. One of my primary

responsibilities was FERC Form 1 preparation and analysis. I also performed general accounting responsibilities and performed forecasting preparation for the regulated subsidiary entities owned by Allegheny Energy, Inc. In addition, I assisted the rate department with a base case filing as well as prepared the revenue requirement calculation on transmission line construction projects.

I was employed at United Health Group from October 2010 to July 2012 as a Senior Accountant. I was responsible for the oversight and accounting functions of two Medicaid managed care organizations.

From May 2001 through September 2003, I was employed at S.R. Snodgrass as a Senior Accountant. S.R. Snodgrass is a regional public accounting firm which performs external and internal audit services for their clients. I functioned as an external auditor assisting in the drafting and inspection of the financial records of clients, which ultimately resulted in issuing an opinion on the authenticity of their financial records.

From June 1985 through April 2001, I was employed at the First National Bank of Herminie. I held various positions when I was employed by the bank. I progressed through all aspects of branch operations which resulted in Branch Manager. I transferred into the finance department as an Accountant and functioned in this capacity until the bank was acquired by The First National Bank of Pennsylvania in April 2001.

Q. Have you previously testified in proceedings before the Board of Public Utilities ("Board" or "BPU")?

A. Yes. I submitted testimony (direct, supplemental and rebuttal) on behalf of JCP&L in the Company's 2012 base rate case in BPU Docket No. ER12111052, direct testimony in the

2016 base rate case in BPU Docket No. ER16040383 and direct testimony in the 2020 base rate case in BPU Docket No. ER20020146.

II. SUMMARY OF TESTIMONY

Q. Please summarize and describe the purpose of your direct testimony.

A. My testimony presents the revenue requirements of JCP&L, which encompass the distribution rate base and operating income and expense for the test year ending June 30, 2023, adjusted for appropriate pro-forma adjustments. My testimony supports JCP&L's Verified Petition seeking an increase in its base rates and charges of $184.95 million or a 6.8% overall average increase in JCP&L's rates.

Q. Please summarize the basis of your revenue requirement testimony.

A. I have prepared, or have had prepared under my direct supervision, a revenue requirement analysis for the test year of July 1, 2022 through June 30, 2023. The filing is based upon six months of actual data from July 1, 2022 through December 31, 2022 and six months of forecasted data from January 1, 2023 through June 30, 2023 (6+6). The filing incorporates proposed adjustments to the test period that are necessary to present distribution operating income representative of operating conditions that will exist when the new rates are effective. The forecasted data will be updated with actual data during the proceeding. In this manner, the record before the Board will contain actual financial data for the full test year at the time that it renders a decision.

Q. Please describe and summarize the schedules to your testimony.

A. My testimony includes five schedules, with supporting pages:

Schedule CAP-1 is a statement of net utility distribution operating income for the test year ending June 30, 2023. The net operating income is presented utilizing actual and forecasted data for the 12 months ending June 30, 2023 (Column 1), adjusted to remove the revenues and expenses relating to reconciling items, such as Tariff Riders and storm damage costs that are subject to deferred accounting, and transmission revenue and expenses (Column 2). The unadjusted distribution income statement (Column 3) is then adjusted to reflect normalized pro forma operating results under present rates (Column 4) and, finally, the resulting pro forma distribution income (Column 5) is adjusted to reflect additional revenues and related tax adjustments requested under the proposed rates (Column 7). Column 6 is the change in revenue requirement necessary to allow JCP&L to earn its proposed rate of return of 7.60% on rate base (*see* direct testimony of JCP&L witness Bill Wang regarding the rate of return on rate base (Exhibit JC-6)).

The adjustments to reflect the normalized pro forma operating results under present rates are set forth on Schedule CAP-2 and are explained individually on pages 2 through 30 attached thereto. The column totals on Schedule CAP-2, page 1, correspond to the adjustment amounts on Schedule CAP-1, Column 4.

Schedule CAP-3 calculates the overall requested revenue change, including the Federal and New Jersey state income taxes associated with that change, as shown on Schedule CAP-1, page 1, Column 6. This schedule also shows the requested rate of return for the test year. Incorporating the capital structure and cost of debt, as set forth in the direct testimony of Bill Wang (Exhibit JC-6), and the recommended return on common equity (10.4%), as set forth in the direct testimony of Dylan D'Ascendis (Exhibit JC-7), the overall rate of return requested is 7.60%.

Schedule CAP-4 computes the actual earned rate of return on rate base at the test year level of operating income, the pro forma level of operating income at present rates and the level of operating income under proposed rates.

Schedule CAP-5 shows the test year-end rate base in detail. Total plant in service reflects projected utility plant investment as of June 30, 2023, plus an additional six months of major capital projects relating to the Advanced Metering Infrastructure ("AMI") capital projects through December 31, 2023. There is a reduction in rate base attributable to pension and other post-employment benefits ("OPEB") as supported in the direct testimony of Tracy Ashton (Exhibit JC-4). The Accumulated Deferred Income Tax ("ADIT") balance included in Rate Base reflects the amortization of property-protected excess deferred income taxes ("EDITs") using the Average Rate Assumption Method ("ARAM"), as approved by the BPU in JCP&L's Tax Cuts and Jobs Act proceeding (BPU Docket No. ER18030226), through the end of the test year. Also, reflected in the ADIT balance is the amortization of property-related unprotected EDITs that have been returned to customers through the Tax Act Adjustment Rider ("Rider TAA") as of the end of the test year. Consistent with JCP&L's prior rate case, the Company acknowledges it will be necessary to reset Rider TAA simultaneously with the effective date of base rates resulting from this case to properly exclude these amounts from Rider TAA. In addition, Rate Base includes a deferred tax asset attributable to Alternative Minimum Tax ("AMT") and an Administrative & General ("A&G") Capitalization Regulatory Asset. Please reference the additional discussion below for further information relating to the AMT deferred tax asset. Additional details relating to the A&G capitalization regulatory asset for FERC Form 1 reporting are described in the testimony of Tracy Ashton in Exhibit (JC-4) as well as

adjustment 24 below. For ratemaking purposes, the plant and reserve amounts relating to the A&G capitalization regulatory asset were removed from JCP&L's plant in-service balances and the accumulated depreciation reserve and included in an A&G capitalization regulatory asset, which regulatory asset was then added to Rate Base.

The Board's long-standing practice regarding post-test year adjustments in base rate cases is based on its decision in *In re Elizabethtown Water Co.*, BPU Docket No. WR8504330 (Order dated May 23, 1985), at 2 ("Elizabethtown Water"), which I will address in more detail later in my testimony. According to the Board's *Elizabethtown Water* precedent, where rate case filings include some historical and some forecasted data, utilities are generally permitted to include in base rate requests known and measurable major capital additions six months beyond the test year. Likewise, ADIT and provision for accumulated depreciation are also reflected as of June 30, 2023, plus estimated accumulated depreciation and ADIT applicable to the six months of distribution major capital spend for the AMI program subsequent to June 30, 2023. All other rate base balances are reflected as forecasted balances as of June 30, 2023, except for Operating Reserve. The Operating Reserve balance is the December 31, 2022 actual balance, which will be updated as the rate case progresses.

The support for the Cash Working Capital component of rate base, based on a lead-lag study, is contained in the direct testimony of Timothy S. Lyons (Exhibit JC-11).

Q. How will the Inflation Reduction Act of 2022 ("IRA") impact FirstEnergy and JCP&L?

A. The IRA imposes a new corporate AMT, beginning in 2023, based on 15% of "adjusted financial statement income" ("AFSI"), which is Generally Accepted Accounting Principles

("GAAP") net income with various adjustments including for federal income taxes, tax depreciation, and pension and other post-employment benefits. Corporations are subject to the AMT if their average AFSI over a three-year period exceeds $1 billion. The AMT for a year is the excess of the "tentative minimum tax" – which is equal to 15% of AFSI – over the regular tax for the year. Thus, the AMT is owed only if the tentative minimum tax for the year is greater than the regular tax for that year. Corporations paying the AMT receive an AMT credit, which can be carried forward, without limitation, and applied against regular federal income tax in a future year in which no AMT is imposed on the corporation. As disclosed in its recently filed SEC Form 10-K for the year ended December 31, 2022, FirstEnergy currently believes that it is more likely than not to be subject to the AMT beginning in 2023, based on interim guidance issued by U.S. Treasury in December 2022. AMT liability must be allocated among members of FirstEnergy's consolidated tax group, including JCP&L.

Q. Is JCP&L subject to the AMT if, as a standalone legal entity, its AFSI is below the $1 billion threshold?

A. Yes. The IRA provides that the $1 billion threshold is determined by reference to the aggregate AFSI of a corporation and its subsidiaries, which in this case means FirstEnergy and all subsidiaries, including JCP&L. If the corporation and its subsidiaries has average AFSI exceeding the $1 billion threshold in the aggregate, then each corporation in the group is deemed to satisfy the $1 billion threshold, regardless of whether it met the threshold individually. Based on interim tax guidance related to the AMT, the average annual AFSI of the FirstEnergy group for years 2020 through 2022 is more likely than not to exceed $1 billion, which would make the AMT applicable to FirstEnergy and its

subsidiaries beginning with the 2023 tax year. The U.S. Treasury and the Internal Revenue Service ("IRS") are expected to publish additional guidance with respect to the AMT. To the extent such guidance changes the computation of AFSI or AMT from how those amounts are interpreted and computed under the current interim guidance, FirstEnergy could be required to change its current AMT estimates for FirstEnergy, and therefore JCP&L, could no longer be subject to the AMT. There is no stated timetable for the issuance of the final guidance.

Q. What is the Company's estimated AMT liability for 2023?

A. The IRA, and current tax guidance published by the U.S. Treasury and the IRS, treat the consolidated tax group as a single entity for purposes of calculating AFSI and AMT liability. Pursuant to FirstEnergy's intercompany income tax allocation agreement, consolidated tax liability, including the AMT, is allocated among the members of the consolidated tax group. In order to determine the amount of the estimated consolidated AMT allocable to each member of the FirstEnergy consolidated tax group, first, each member's AMT liability, including JCP&L's, was computed on a separate entity basis as an amount equal to the excess (if any) of: (i) FirstEnergy's estimated consolidated AMT for the tax year over, (ii) FirstEnergy's estimated consolidated AMT for the year, computed by excluding the member's estimated standalone AFSI computed according to its individual books and records. Second, FirstEnergy's consolidated AMT liability was allocated among the members of the consolidated tax group, including JCP&L, based on a ratio of each member's estimated separate entity AMT computed in the first step to the sum of the estimated separate entity AMT liabilities of each consolidated group member computed in the first step. Based on the interim guidance from the U.S. Treasury and IRS

discussed above, and FirstEnergy's current estimates, JCP&L's share of AMT liability for the full tax year 2023 is estimated to be approximately $25.7 million and the first half of 2023 will be $12.9 million, of which approximately 74%, or $9.5 million, is attributable to distribution operations. Thus, through June 30, 2023, the distribution-related share of JCP&L's estimated 2023 AMT liability is approximately $9.5 million.

Q. **Does the application of AMT impact the calculation of book income tax expense for ratemaking purposes?**

A. It does not. JCP&L calculates test year income state and federal income taxes using statutory regular income tax rates and the AMT is not expected to impact the tax rates.

Q. Why does the Company believe it is appropriate to include the AMT Deferred Tax Asset ("DTA") in rate base?

A. Because AMT expenses later manifest as a tax credit to offset future regular tax liability, it represents a timing difference between the payment of the AMT tax and the application of the credit. Therefore, AMT expenses are appropriately accounted for as deferred tax assets ("DTA") on the Company's books. For the same reasons other deferred tax assets or liabilities are included in rate base, it is proper to include AMT DTAs in rate base because the Company provides cash funding for these AMT payments. Therefore, including these DTAs in rate base enables recovery of its financing cost associated with AMT expenses, until applied to future regular tax liability. Also, since JCP&L uses statutory regular income tax rates to calculate state and federal income taxes for ratemaking purposes, AMT expense otherwise would not be considered in its revenue requirement.

Q. How will the Company account for the AMT on its financial statements?

A. As explained, JCP&L is entitled to a tax credit for any amount of AMT it pays. Therefore, as of June 30, 2023, JCP&L will record a deferred tax asset in the form of an AMT credit ("AMT Credit DTA") in the approximate amount of $9.5 million for AMT estimated payments made as of such date that relate to its distribution operations. For income tax accounting purposes, JCP&L will record a current income tax liability and current income tax expense equally offset by the AMT Credit DTA and a reduction to deferred income tax expense. Thus, there should be no net incremental income tax expense caused by the AMT. JCP&L proposes to include the AMT Credit DTA in the accumulated deferred income tax balance as of June 30, 2023, and thus it will be an increase to rate base. JCP&L's allocable share of AMT liability may change as FirstEnergy's financial forecast is updated or as future guidance is issued by the U.S. Treasury and the IRS.

III. SUMMARY OF RATE INCREASE AND COMPARISION WITH OTHER EDCS

Q. Based on your revenue requirements analysis, is JCP&L requesting an increase in base rates?

A. Yes. As set forth in Schedule CAP-3, JCP&L is requesting an increase in base rate revenues of $184.95 million on an annual basis or approximately a 6.8% overall average increase in JCP&L rates.

Q. How do JCP&L's rates, including the proposed increase, compare with those of the other New Jersey electric distribution companies ("EDCs")?

A. JCP&L has the lowest delivery and lowest total residential electric rates among the New Jersey EDCs. Due to economies of scale associated with being part of a large utility holding company system and through prudent management, JCP&L has maintained low

base rates as shown in the chart below. Even after the proposed rate increase, JCP&L's delivery and total residential electric rates will still be the lowest among the four New Jersey EDCs.

Monthly Bill Comparison[1]					
Class/Company	BGS	Delivery	Current Monthly[2]	Proposed Delivery	Proposed Monthly
Residential[3]					
JCP&L	$ 73.16	$ 40.05	$ 113.21	$ 48.50	$ 121.66
ACE	$ 86.02	$ 76.84	$ 162.85		
PSE&G	$ 102.53	$ 44.03	$ 146.56		
RECO	$ 80.36	$ 65.76	$ 146.12		
Commercial[4]					
JCP&L	$ 745.59	$ 388.84	$ 1,134.44	$ 490.64	$ 1,236.23
ACE	$ 994.67	$ 868.59	$ 1,863.26		
PSE&G	$ 1,224.05	$ 547.36	$ 1,771.41		
RECO	$ 823.38	$ 601.27	$ 1,424.65		
(1) Current bills are based on Tariff published as of March 1, 2023 for all EDCs					
(2) Annualized average based on 4 summer months and 8 winter months					
(3) Residential amount based on JCPL typical RS usage of 973 kWh/month in Summer and 684 kWh/month in Winter					
(4) Commercial amount based on 40kW, 10000kWh per month.					

IV. RELATED TESTIMONY OF OTHER JCP&L WITNESSES

Q. Please identify any testimony by other witnesses that relates to and supports your testimony.

A. Several Company witnesses have sponsored or explained test year adjustments that I have incorporated into my revenue requirements calculation:

JCP&L witness Mark Mader (Exhibit JC-2) has presented direct testimony that includes a discussion of the Company's distribution revenues for the twelve months ending June 30, 2023. Mr. Mader's proposed revenue weather normalization has been included as an adjustment to the test year (*see* Schedule CAP-2, Adjustment No. 1), based on actual data

for July 1, 2022 through December 31, 2022 and forecasted data for the period from January 1, 2023 to June 30, 2023. In addition, Mr. Mader has included the calculation of the Company's adjustment to Rate Base to include a Consolidated Tax Adjustment in his direct testimony (*see* Schedule MAM-1). Mr. Mader has included testimony in support of the Company collecting a carrying charge on Legacy Meters, which are no longer in Rate Base, while the Company is deploying Smart Meters (*see* Schedule CAP-2, Adjustment No. 11) under its BPU approved AMI Plan (BPU Docket No. EO20080545). Mr. Mader testifies to a normal level of major storm amortization expense, based on the average regulatory asset balance over an approximately five-year amortization period (*see* Schedule CAP-2, Adjustment 15). Mr. Mader has also included in his testimony support to recover increases in Contract Labor and Fuel costs (*see* Schedule CAP-2, Adjustment 23).

JCP&L witness Yongmei Peng (Exhibit JC-9) has presented direct testimony on proposed changes to the Company's Tariff for Service, including changes related to certain fees in Part II of the Tariff.

JCP&L witness Ms. Ashton (Exhibit JC-4) has presented direct testimony that includes a discussion of pension and OPEB expenses. Ms. Ashton's direct testimony supports the appropriate level of pension and OPEB expense to be included in the test year, which I have included in my revenue requirement calculation (*see* Schedule CAP-2, Adjustments No. 10 and 10(a)). In addition, Ms. Ashton supports the recovery of Adjustment No. 24 relating to the continued recovery of the administrative and general overhead costs that have been reclassified on the FERC Form 1 financial statements, resulting from the FERC audit. Finally, Ms. Ashton's testimony proposes a deferral mechanism for pension and OPEB expenses.

JCP&L witness Dennis Pavagadhi (Exhibit JC-5) has presented direct testimony regarding vegetation management expense and storm restoration expense during the test year that supports my Adjustments No. 12 and 15 (*see* Schedule CAP-2, Adjustments No. 12 and 15).

JCP&L witness John Ahr (Exhibit JC-12) has presented direct testimony regarding the AMI Plan capital expenditures relating to Smart Meters, Hardware, Software, and AMI incremental Operation & Maintenance "O&M" expense (*see* Schedule CAP-2 Adjustment 11).

JCP&L witness Kenneth Strah (Exhibit JC-13) has presented direct testimony regarding the Low Income and the Senior Citizen Discount programs. (See Schedule CAP-2, Adjustment 22).

V. PRO FORMA ADJUSTMENTS

Q. Can you highlight some of the pro forma adjustments the Company is including in this filing?

A. Yes. The Company has made adjustments to the test year income statement for the Electric Vehicle ("EV") Regulatory Asset amortization (Adjustment 9); AMI Regulatory Asset amortization (Adjustment 11); Vegetation Management O&M (Adjustment 12); Storm regulatory asset recovery using approximately a 5-year amortization period (Adjustment 15); Low Income Program O&M recovery & Senior Citizen Discount program (Adjustment 22); Contract Labor/Fuel Cost increases (Adjustment 23); and Capitalized Administrative and General overhead costs regulatory asset amortization (Adjustment 24).

Q. Can you expand on the post-test year adjustments that are permitted to reflect the ongoing level of costs beyond the test year?

A. Yes. According to the Board's *Elizabethtown Water* precedent, where rate case filings include some historical and some forecasted data, utilities are generally permitted to include in base rate requests known and measurable adjustments three months beyond the test year for changes in capital structure, six months beyond the test year for rate base and nine months beyond the test year for revenue and expense, which is generally referred to as the "3-6-9" rule.

Q. Is JCP&L proposing adjustments beyond the test year in this filing?

A. Yes. JCP&L has included out-of-period adjustments to: 1) reflect its forecasted capital structure as of September 30, 2023 (three months beyond the end of the test year); 2) its rate base to reflect significant plant additions and plant-related adjustments through December 31, 2023 (six months beyond the end of the test year); and 3) known and measurable adjustments to O&M expense, specifically: 1) wage and salary increases for employees; 2) AMI costs; 3) EV Program costs; 4) increases in costs for contract services, including traffic control services, underground locating services and distribution wood pole inspection services; 5) fuel costs that fall within nine months after the test year; and 6) Pension & OPEB costs through December 31, 2023.

Q. Please describe the adjustments summarized on Schedule CAP-2, page 1, and indicated individually on Schedule CAP-2, pages 2 through 27.

A. Adjustment 1 – Revenue Normalization: Normalizes actual test year revenue for the effects of weather. Refer to the direct testimony of Mark A. Mader (Exhibit JC-2).

Adjustment 2 – Tariff Revisions: Reflects the tariff adjustment as proposed by Yongmei Peng in her direct testimony (Exhibit JC-9). The Company is proposing an increase in the Field Collection Charge and a decrease in the Reconnection Charge.

Adjustment 3 – Interest on Customer Deposits: Reflects the reclassification to operating expense of interest on customer deposits at the rate of 1.40% based upon the estimated customer deposit balance at June 30, 2023. The Customer Deposit balance is a deduction from rate base. The calendar year 2023 interest rate is equal to the average rate on six-month Treasury Bills for the 12-month period ending September 30, 2022, as approved by the Board on November 30, 2022.

Adjustment 4 – Annualize Payroll Wage Rate Increases: Reflects the annualization of salary and wage increases using a 3% average increase for bargaining employees. Also, this adjustment reflects the annualization of salary and wages increases for non-bargaining employees using a 4% and 3% average increase for March 1, 2023 and 2024, respectively. This adjustment applies to those employees who are covered by a collective bargaining agreement and will receive an actual 3% salary and wage increase during 2023 under that agreement. Because not all salary and wage increases are effective on January 1, 2023, the salary and wages were annualized for purposes of this adjustment to reflect a full year of the increases. This adjustment also provides for the share of the Company's 401k retirement savings ("Savings Plan") and Federal Insurance Contributions ("FICA") tax expenses resulting from the salary and wage increase (Adjustments 4(a) and 4(b)).

Adjustment 4 is consistent with the Board's long-standing practice regarding post-test year adjustments to O&M expense based on its decision in *Elizabethtown Water*. According to the Board's *Elizabethtown Water* precedent, where rate case filings include

some historical and some forecasted data, utilities are generally permitted to include in revenue requirement requests known and measurable adjustments to O&M expense nine months beyond the test year.

Adjustment 5 – Reclassify Amortization of Net Loss on Reacquired Debt: Reflects the reclassification of the amortization of the net loss on reacquired debt from interest charges to operating expense reflected on a distribution basis. Under GAAP, if debt is terminated or significantly modified, the Company must recognize, with a charge to income or expense, any gain or loss associated with the termination and any deferred issuance costs, in the period that debt is terminated or significantly modified. Deferred net unamortized gain/loss on reacquired debt occurs when there is a redemption or reacquisition of long-term debt and there exists remaining unamortized original debt expense or discounts and/or financing costs relating to the original debt issuance. The balance of the net gains/losses on reacquired debt is amortized in interest expense over the remaining original life of the debt. These costs are treated as regulatory assets for financial reporting purposes because they qualify as such under GAAP due to the approval of the Board to recover these deferred gains and losses. It is the practice of JCP&L and the Board to include this expense in the test year and this adjustment has been reflected in prior base rate proceedings in the same manner.

Adjustment 6 – BPU and Rate Counsel Assessments: Reflects a normalized level of Board and Division of Rate Counsel assessments. This adjustment is based upon the normalized test year revenues and 2023 actual assessment rates; however, the amount will be adjusted to reflect the revenue requirement approved by the BPU.

Adjustment 7 – Management Audit: This adjustment reflects recovery of Board-mandated management audit consultant fees. The Management Audit fees are based on JCP&L's recent BPU Management and Affiliate Standards Audit and are calculated at the Board-approved consultant's contracted amount of $1,469,584 amortized over a four-year period, which results in a $367,396 test year adjustment. This four-year amortization period is consistent with the amortization period granted in previous rate cases. Specifically, this four-year amortization is consistent with the Board's decisions in the two most recent fully litigated Base Rate Cases, which include the Company's 2002 Base Rate Case, Docket No. ER02080506, Order issued May 17, 2004, and the 2012 Base Rate Case, Docket No. ER12111052, Order issued on March 26, 2015.

Adjustment 8 – Rate Case Expenses: Reflects 50% of the estimated expense associated with base rate proceedings. This adjustment includes an estimated rate case amortization amount for this proceeding that will be updated throughout and at the conclusion of this proceeding.

Adjustment 9 – Electric Vehicle Regulatory Assets: Reflects a proposed amortization of the Electric Vehicle Regulatory Assets over a five-year period. By Board Order dated September 23, 2020, the Board directed all EDCs to file electric vehicle proposals by February 28, 2021. On March 1, 2021, JCP&L filed a petition with the Board requesting approval of a proposed EV program. The Board issued an order on June 8, 2022, approving the Stipulation of Settlement in BPU Docket No. EO21030630. The Company is requesting recovery over a five-year period of the approved deferred regulatory assets, which are the EV Investment Regulatory Asset and the EV O&M Regulatory Asset.

The EV Investment Regulatory Asset consists of a return on Average Monthly Rate Base, deferred depreciation/amortization associated with Utility Make Ready distribution upgrades and IT Systems, Customer Make-Ready Incentives and Customer Rate Incentives. The Customer Make-Ready Incentive has been paid to customers at varying amounts for the installation of a qualified Level 2 ("L2") charger or DCFC charger. The Customer Rate Incentives include bill credits that have been paid to encourage residential and multi-family customers to use chargers during off-peak hours and demand charge credits associated with customers with DCFC chargers.

The EV O&M Regulatory Asset includes deferred O&M and the approved carrying charge utilizing 2-year treasury rates plus 60 basis points (*see* BPU Order in Docket No. QO19010040 at paragraph 52).

Adjustment 10 – Pension and OPEB: Reflects the adjustment for pension (Adjustment No. 10) and OPEB (Adjustment No. 10(a)), as supported in the direct testimony of Tracy Ashton (Exhibit JC-4). This calculation adjusts the test year Pension and OPEB expense (July 1, 2022 through June 30, 2023) (which include mark-to-market gains or losses) to reflect 2023 Pension and OPEB expense, calculated according to the delayed recognition methodology. The Company recorded an adjustment to OPEB assets in December 2022 and has reflected the impact on the 2023 expense in its adjustment, since the expense, post-accounting adjustment, is more indicative of what the actual OPEB expense will be going forward. To reflect pension and OPEB over the same period, the Company has also reflected 2023 expense in its adjustment to pension expense. Because of the significant change in pension asset value in 2022, 2023 pension expense (vs. 2022) is more reflective of pension expense the Company will incur in the near-term going forward. As book

pension and OPEB costs are established for each calendar year in January, these costs are known and measurable for the calendar year, with expense being net of the amounts capitalized. Extending test year expense six months beyond the test year would be congruent with the Board's long-standing practice regarding post-test year adjustments to O&M expense based on its decision in *Elizabethtown Water* as mentioned earlier in my testimony. Please refer to the direct testimony of Tracy Ashton (Exhibit JC-4) for further discussion relating to the regulatory treatment of Pension & OPEB.

Adjustment 11 – Amortization of AMI Regulatory Assets: Reflects a 10-year amortization of the AMI Investment and O&M deferred regulatory assets, which results in a $1,813,564 test year adjustment.

The Company was granted deferral authority for three regulatory assets in the AMI Program proceeding in BPU Docket No. EO20080545 dated February 23, 2022, which were described in paragraph 33 of the order as the "AMI Investment Regulatory Asset", "AMI Stranded Cost Regulatory Asset" and the "AMI O&M Regulatory Asset". Paragraph 33 further states that the Company will either book or track, or some combination thereof, a regulatory asset "AMI Investment Regulatory Asset" comprised of its AMI Plan related capital investment ("AMI Investment Deferral"). JCP&L will also book a regulatory asset ("AMI Stranded Cost Regulatory Asset") comprised of the associated stranded costs on legacy meters ("AMI Stranded Cost Deferral"). JCP&L will also book a regulatory asset ("AMI O&M Regulatory Asset") comprised of the incremental O&M deferred costs associated with the AMI Plan ("AMI O&M deferral").

The signatory parties agreed in paragraph 37 that the Company would defer incremental AMI-related O&M costs associated with the AMI implementation into a

separate regulatory asset without a return for recovery in subsequent base rate cases, if deemed reasonable and prudent. The Company will track actual O&M cost savings during the Pre-Deployment and Deployment Phases under the AMI Plan and will adjust the Incremental AMI-related O&M costs that have been deferred to reflect O&M savings resulting from the AMI Plan in the subsequent base rate cases. Based on the testimony of John Ahr in this case regarding its progress toward O&M savings described in the AMI Plan, JCP&L has only just begun the Deployment Phase of its AMI Plan and, as such, does not expect to realize operating savings during the test year. Therefore, the proposed test year adjustment to begin to amortize the AMI O&M Regulatory Asset includes no offset for operating savings. John Ahr's direct testimony (Exhibit JC-12) provides a more detailed discussion of the AMI program and the Company's progress toward O&M savings described in the AMI plan.

Paragraph 35 describes the components of the "AMI Investment Regulatory Asset" as the carrying costs, cost of removal and depreciation and amortization. As stated in paragraph 36, the recovery of the Stranded Cost Regulatory Asset shall be excluded from cost recovery until the subsequent base rate case associated with full deployment of the AMI (full deployment occurs at the conclusion of the Company's Deployment Phase as defined in paragraph 25 of the Stipulation), which according to the deployment schedule would be December 31, 2025. Furthermore, paragraph 36 states that the Company may request a return on the Stranded Cost Regulatory Asset balance in a subsequent base rate case. Mark Mader's direct testimony (Exhibit JC-2) further discusses the AMI Stranded Costs amounts and the carrying charge proposal.

Adjustment 12 – Normalize Vegetation Management Expense: Reflects the adjustment to normalize the test year vegetation management expense. The adjustment is to address increases in vegetation management O&M costs incurred to continue to meet the changes in vegetation management standards instituted in 2016, along with increased labor expenses for vegetation management activity and increased expenses for removal of hazard and danger trees.

The Company is currently recovering $31M in vegetation management costs in distribution base rates. The Company is requesting to increase the annual amount to $42,640,000. There are three components of this adjustment. The first component is $3.4 million, which reflects actual spending in the test year that exceeded the budget for the period of July to December 2022. The second part of the adjustment reflects increased costs for external vegetation management labor contracts. Under the Company's contracts for vegetation management services, JCP&L is responsible for increases in union wages. The prior labor contracts expired as of December 31, 2022 and included wage rate adjustments of 3.0% each year for the 2020-2022 period. The new labor contracts provide for increases of 4.25% for 2023, 4.5% for 2024, 3.5% for 2025, and an additional $0.25 per hour increase for healthcare costs. The portion of the adjustment related to the increased labor contract costs is $1,640,000. The third part of this adjustment is $10 million (which includes the $3.6 million cited above) and reflects an increased level of expense for the removal of identified hazard and danger trees off-corridor, which are the leading source of tree caused outages. The direct testimony of Dennis Pavagadhi (Exhibit JC-5) provides additional information regarding the Company's vegetation management program and

performance. The total pro forma adjustment for vegetation management expense is $8.3 million, as shown on Schedule CAP-2 (Adjustment 12).

Adjustment 13 – Annualize Depreciation Expense: Reflects the annualization of depreciation expense based upon the estimated net depreciable plant balance at June 30, 2023, and includes, six months of additional distribution major capital projects relating to the AMI programs from July 1, 2023 through December 31, 2023. The distribution and general plant balances were reduced by the FERC Capitalized A&G costs that resulted from the FERC Audit with a proposed amortization amount included in Adjustment 24 below. The depreciation rates applied in this adjustment utilize the results of the depreciation study conducted and supported by JCP&L witness John Spanos (Exhibit JC-10). Additional information relating to the A&G Capitalized Regulatory Asset can be referenced in Ms. Ashton's testimony (Exhibit JC-4).

Adjustment 14 – Average Net Cost of Removal/Salvage: Reflects annual accrual expense for net salvage, which accrual rates were established based on five-years of historical costs. This approach is consistent with BPU precedent and is further described in the direct testimony of JCP&L witness John Spanos (Exhibit JC-10).

Adjustment 15 – Storm Damage Cost Amortization: Reflects the amortization of deferred storm costs of $310.2M, as of December 31, 2022 at $59 million per year, which is approximately a five-year amortization period. This results in a pro forma adjustment of $30 million to increase the $29 million currently recovered in storm amortization to $59 million. Mr. Mader is requesting a shorter amortization and recovery period for its deferred storm balance to provide additional cash to support distribution investments, reduce the level of required borrowings and alleviate further pressure on JCP&L's credit metrics.

Please refer to the direct testimony of Mark Mader (Exhibit JC-2) for further discussion of the Company's storm damage cost amortization proposal.

Adjustment 16 – FESC depreciation expense at JCP&L Rates: JCP&L has presented an updated depreciation study as part of this base rate case. The adjustment reflects FESC depreciation expense by applying JCP&L's depreciation rates, as included in the updated depreciation study conducted by Gannett Fleming to allocated FESC plant. The calculation of depreciation expense in this adjustment is consistent with the methodology set forth in the direct testimony and depreciation study of JCP&L witness John Spanos (Exhibit JC-10). In addition, the allocation percentage of 15.44% was applied, which is the Multi Factor-Utility & Non-Utility allocation percentage effective January 1, 2023.

Adjustment 17 – SERP/EDCP/CBRP: Reflects the reduction to the income statement expense relating to the non-qualified plans relating to the Supplemental Executive Retirement Plan, Executive Deferred Compensation Plan and the Cash Balance Retirement Plan because the Company is not requesting recovery of these expenses.

Adjustment 18 – Advertising & Other Expenses: Removes non-operating and/or non-recoverable expenses from test year expense. Non-operating and/or unrecoverable costs are generally related to advertising, lobbying, sponsorships, and competitive services. The Company has reviewed charges to JCP&L during the test period, focusing on organizations within FirstEnergy that conduct activities or perform functions which costs are considered non-operating and/or unrecoverable. JCP&L reviewed charges to FERC accounts 908, 909, 913, 930.1 and 930.2. In total, the Company removed $746,134 of O&M expenses from the test year.

Adjustment 19 – Reconciliation of the Amortization of EDITs: Reflects the reconciliation of the amortization of property-protected EDITs using ARAM, as included in the regulatory asset in accordance with paragraph 21 of the Stipulation of Settlement approved in the Tax Cuts and Jobs Act 2017 proceeding in BPU Docket No. AX18010001.

Adjustment 20 – BGS Administrative Labor: Reflects the adjustment to remove BGS administrative labor from the distribution test year in the amount of $102,860. This amount includes actual labor expense for the period of July 1, 2022 through December 31, 2022 and an estimated amount for the period of January 1, 2023 through June 30, 2023, and the estimates will be revised in the "9+3" and "12+0" updates. The "Financial Audit of the New Jersey Electric Distribution Companies Basic Generation Administrative Expense and other Related Expenses" in BPU Docket No. EA17010004 dated July 15, 2020, with order effective on July 25, 2020, recommended that the EDCs include administrative costs as part of the BGS deferral. Specifically, the Board Order instructed the EDCs to implement 14 recommendations in the Final Report, which included recommendation numbers 3, 11 and 12. The recommendations called for the EDCs to track BGS administrative costs that are similar in relation to their genesis and function as those charged by Atlantic City Electric Company through its BGS Reconciliation Charge and to propose an appropriate amount to be included in the Company's next base rate case as a reduction in base rates and to, instead, be recovered as part of the Company's BGS Reconciliation Charge.

Adjustment 21-VOSA Regulatory Asset Recovery: The Company has a current balance in the Veteran's Organization Service Application ("VOSA") Regulatory Asset of $10,581 and is not seeking recovery at this time but reserves that it may submit these costs for consideration in a subsequent base rate case. The VOSA Regulatory Asset relates to the

In The Matter of the Verified Petition of Jersey Central Power & Light Co. Seeking Review and Approval of the Veteran's Org. Serv. Application and Tariff, BPU Docket No. ER19010013 (order dated February 27, 2019) ("VOSA Order"), which was effective on March 9, 2019. The VOSA Order granted JCP&L deferral authority, until its next base rate case, for lost revenues associated with the implementation of legislation requiring public utilities to charge veterans' organizations the residential rate for service delivered to the property at which the veterans' organization primarily operates.

Adjustment 22-Low Income O&M & Senior Citizen Discount: Reflects an adjustment to include an annual expense amount of $638k and $1.9 million associated with a new dedicated Customer Advocacy Team and a Senior Citizen Discount program, respectively. Please refer to the direct testimony of Kenneth Strah (Exhibit JC-13) for further discussion of the Company's Low Income and Senior Citizen Discount proposal.

The Company also requests deferred accounting for the discounts associated with the new Senior Citizen Discount Program to ensure that the Company collects only the discounts provided based on actual participation. Amounts deferred will be reviewed, amortized and recovered through subsequent base rate cases.

Adjustment 23 – Contract Labor and Fuel Cost Adjustment: Please refer to the direct testimony of Mark Mader (Exhibit JC-2) for a discussion of the Company's Contract Labor & Fuel adjustment proposal.

Adjustment 24- A&G Capitalized Regulatory Asset Amortization: Please refer to the direct testimony of Tracy Ashton (Exhibit JC-4) for a discussion of the FERC audit and resulting changes to A&G capitalization methodology. FirstEnergy implemented the results of the audit by reclassifying certain plant and reserve for the amounts capitalized between years

2015 and 2021 to the A&G capitalization regulatory asset for FERC Form 1 reporting. The Company is proposing to continue to include the A&G capitalization regulatory asset in rate base and to recover this regulatory asset by amortizing the balance removed from each plant account and included in this regulatory asset by applying the current approved depreciation rates, as approved by the BPU, applicable to the plant account from which each balance was removed.

Adjustment 25 – Investment Tax Credit Amortization: Reflects the amortization of the distribution portion of the Investment Tax Credit ("ITC"). This adjustment is consistent with Board orders in the Company's prior base rate cases.

Adjustment 26 – Interest Synchronization-Tax on Long Term Debt: Synchronizes the federal and state income tax savings associated with rate base, with the weighted cost of debt in the capital structure used to support rate base. This adjustment is consistent with Board orders in the Company's prior base rate cases.

Adjustment 27 – Income Taxes on Adjustments: Computes the effect on federal and state income taxes relating to the normalization adjustments 1 through 24.

Adjustment 28 – ARAM tax amortization: Computes an adjustment to test year income tax expense resulting from a comprehensive federal tax reform bill commonly known as the Tax Cuts and Jobs Act ("TCJA") enacted on December 22, 2017. Utilities book large reserves to account for deferred taxes resulting from the excess of accelerated tax depreciation over straight-line depreciation used for regulatory purposes. The reduction in the corporate tax rate generally creates excess reserve because previously recorded reserves assumed a 35% corporate tax rate, and a 21% rate reduces deferred tax expense. This EDIT was addressed in JCP&L's TCJA proceeding in BPU Docket Nos. AX18010001 and

ER18030226. Per Paragraph 19 of that Order, the parties agreed that base rates would be adjusted to reflect the amortization of the property-related protected EDIT asset using the ARAM. Therefore, this adjustment serves to adjust JCP&L's base rate tax amount for the impact of the EDIT amortization net of tax.

Q. Has the Company included an adjustment related to the Lost Revenue Adjustment Mechanism ("LRAM") in the revenue requirement?

A. An LRAM is a rate adjustment mechanism that allows a utility to recover revenues that are reduced specifically as a result of energy efficiency ("EE") programs. The revenue requirement does not include an adjustment to revenue or Operation & Maintenance "O&M" expense for LRAM. The revenue included in the test year revenue requirement is weather normalized distribution revenue, excluding any adjustment for LRAM revenue. In a base rate case, revenues are set to recover the utility's revenue requirement. This action, for the most part,[1] resets or restores the impacts of energy efficiency programs on base rates since the utility's last base rate case. The Company will make appropriate adjustments to the LRAM deferral for the differences between the annualized EE impacts and the EE impacts captured in the test year.

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

A. Yes, it does.

[1] The test year does not reflect the annualized impacts of EE projects completed during the test year, only part-year impacts, depending on when the projects were placed in service. The difference between the annualized impacts and the impacts captured in the test year will calculated and included in the LRAM deferral.

JERSEY CENTRAL POWER & LIGHT COMPANY
Pro Forma Statements of Net Utility Operating Income for the Twelve Months Ended 6/30/23
Normalized and Adjusted to Reflect the Effect of Known Major Changes and Proposed Rates

Line No.		Unadjusted Total Company (a) (1)	Non-Distribution Adjustments (b) (2)	Unadjusted Distribution (3)	Normalization Adjustments (4)	Pro Forma Present Rates (5)	Additional Revenue to Achieve Return (6)	Requested Pro Forma Proposed Rates (7)
1	Electric Retail Sales	$ 1,950,301,454	$ (1,295,332,075)	$ 654,969,379	$ (12,292,767)	$ 642,676,612	$ 184,953,113	$ 827,629,725
2	Sales for Resale	8,669,059	(8,669,059)	-				
3	Total Electric Sales	$ 1,958,970,513	$ (1,304,001,134)	$ 654,969,379	$ (12,292,767)	$ 642,676,612	$ 184,953,113	$ 827,629,725
4	Other Operating Revenue	118,579,921	(103,782,445)	14,797,476	(2,352,171)	12,445,306		12,445,306
5	Total Revenue	$ 2,077,550,434	$ (1,407,783,579)	$ 669,766,855	$ (14,644,938)	$ 655,121,918	$ 184,953,113	$ 840,075,031
6	O&M - Production	977,913,532	(977,913,532)	-	-	-		-
7	O&M - Transmission	68,586,463	(68,586,463)	-	-	-		-
8	O&M - Distribution	196,531,106	(43,625,007)	152,906,099	15,986,980	168,893,080		168,893,080
9	O&M - Customer Accounts	44,508,910	(11,437,245)	33,071,665	-	33,071,665		33,071,665
10	O&M - Customer Service	146,902,755	(136,422,718)	10,480,037	-	10,480,037		10,480,037
11	O&M - Sales Expense	4		4		4		4
12	O&M - A&G	123,845,880	(49,234,580)	74,611,301	27,384,486	101,995,787		101,995,787
13	Subtotal Operation & Maintenance	$ 1,558,288,650	$ (1,287,219,545) -	$ 271,069,106	$ 43,371,467	$ 314,440,573	$ -	$ 314,440,573
14	Depreciation & Amortization	217,878,450	(61,725,305)	156,153,145	13,891,594	170,044,739		170,044,739
15	Regulatory Debits	45,491,399	(13,422,311)	32,069,088	33,422,086	65,491,174		65,491,174
16	Regulatory Credits	(49,888,170)	49,548,053	(340,117)	367,396	27,279		27,279
17	Taxes Other Than Income	10,341,001	(1,823,301)	8,517,700	399,901	8,917,601		8,917,601
18	Accretion Expense	403,950		403,950		403,950		403,950
19	Total Operating Expenses	$ 1,782,515,280	$ (1,314,642,409)	$ 467,872,872	$ 91,452,444	$ 559,325,316	$ -	$ 559,325,316
20	Operating Income Before Income Taxes	295,035,154		201,893,984	(106,097,382)	95,796,601	184,953,113	280,749,714
21	Income Taxes	25,835,799		56,752,399	(55,042,646)	1,709,753	51,990,320	53,700,073
22	Net Utility Operating Income	$ 269,199,355		$ 145,141,585	$ (51,054,736)	$ 94,086,848	$ 132,962,793	$ 227,049,641

(a) Includes July to December 2022 actuals and forecasted January to June 2023 income statement.
(b) Consists of revenues and expenses related to transmission operations and reconciling revenue and expense items.

JERSEY CENTRAL POWER & LIGHT COMPANY
Summary of Test Year Normalization/Annualization Adjustments

Adjmt. No.		Revenue (1)	O&M (2)	Depreciation (3)	Amortization (4)	Taxes (5)	Total (6)
1	Revenue Normalization Adjustment	(14,766,262)					
2	Tariff Fee Adjustments	121,324					
3	Interest on Customer Deposits		517,477				
4	Annualize Salary and Wage Rate Increases		5,227,469				
4(a)	Savings Plan - Company Contribution for S&W Increase		156,824				
4(b)	FICA Tax on annualized S&W Increases					399,901	
5	Reclass Amortization of Net Loss on Reacquired Debt		619,772				
6	BPU & Rate Counsel Assessments		843,045				
7	Management Audit Fee Amortization				367,396		
8	Rate Case Expenses				25,056		
9	EV Recovery				445,552		
10(a)	Pension		14,294,389				
10(b)	OPEB		4,904,994				
11	AMI Regulatory Asset Recovery				1,813,564		
12	Normalize Vegetation Management Expense		8,276,658				
13	Annualize Depreciation Expense			9,581,673			
14	Average Net Salvage			4,309,921			
15	Storm Damage Cost Amortization				30,000,000		
16	Service Company Depreciation Expense at JCP&L Rates		1,872,457				
17	SERP/EDCP/CBRP		4,921,662				
18	Advertising & Other Expenses		(746,134)				
19	ARAM Amortization				(237,191)		
20	BGS Administrative Labor included in BGS Deferral		(102,860)				
21	VOSA						
22	Low Income O&M & Senior Citizen Discount		2,504,253				
23	Contract Labor and Fuel Costs		81,460				
24	A&G Capitalization Regulatory Asset Amortization				1,375,105		
25	Investment Tax Credit Amortization					(97,035)	
26	Interest Synchronization - Tax on Long Term Debt					(18,467,979)	
27	Income Taxes on Adjustments					(29,823,974)	
28	Tax Reform Amortization					(6,653,658)	
	Total Adjustments	(14,644,938)	43,371,467	13,891,594	33,789,482	(54,642,744)	51,054,736

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 1

Adjustment to retail distribution revenue for weather normalization.

Electric sales (distribution) revenue 12ME June 2023	654,969,379	(a)
Weather-normalized distribution revenue	640,203,117	
Adjustment to total revenue	(14,766,262)	

Electric sales (distribution) revenue 12ME June 2023	654,969,379
Weather normalized distribution revenue (based on billing determinants)	642,676,612
Adjustment to retail revenue	(12,292,767)

Adjustment to retail revenue	(12,292,767)
Misc adjustments to other operating revenue	(2,473,495)
Adjustment to total revenue	(14,766,262)

(a) Reference schedule CAP-1, column 3, line 1.

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 2

Adjustment to other operating income to reflect proposed fee changes in Tariff Part III - Service Classifications.

	Test Year Other Oper Rev (1)	Current Fee (2)	No. of Occurrences (1)/(2)=(3)	Proposed Fee (4)	Estimated Annual Revenue (3)x(4)=(5)	Adjmt to Other Revenue (5)-(1)
Reconnection Charge	$ 61,258	$ 45.00	1,361	$ 35.00	$ 47,635	$ (13,623)
Field Collection Charge	$ 337,377	$ 25.00	13,495	$ 35.00	$ 472,325	$ 134,948
Total Adjustment to Other Operating Revenue						$ 121,324

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 3

Adjustment to reclassify and annualize interest on customer deposits.

Forecasted customer deposits balance at 06/30/2023	$ 36,962,658	
Interest rate 2023	1.40%	(a)
Annualized interest on customer deposits	$ 517,477	

(a) Based upon the average yield on new six month Treasury Bills for the 12-month period ending September 30, 2022.

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 4, 4(a) and 4(b)

Adjustment (4) reflects annualized salary and wage ("S&W") rate increases (WRI) effective November 1 and May 1 for bargaining and March 1 for non-bargaining employees, respectively. Additional adjustments for the impact of the S&W increase was applied to the savings plan 4(a) and FICA tax 4(b).

	Total straight-time labor cost		
	Bargaining	Non-Bargaining	Total
Annualized S&W cost with WRI	$ 64,759,248	$ 33,602,703	$ 98,361,951
12 months ending June 2023 test year amount	61,347,011	31,787,471	93,134,482
Adjustment No. 4	$ 3,412,237	$ 1,815,232	$ 5,227,469

Total savings plan - Company contribution for annualized Salary & Wage Increase	*			
	Bargaining	3%	$	102,367
	Non-Bargaining	3%		54,457
Adjustment No. 4(a)	TOTAL		$	156,824

Total FICA tax on annualized S&W Increase	**			
	Bargaining	7.65%	$	261,036
	Non-Bargaining	7.65%		138,865
Adjustment No. 4(b)	TOTAL		$	399,901

* Company contributes 50 cents per dollar up to 6%.
** Federal Insurance Contribution Act "FICA"-Social Security rate of 6.2% plus 1.45% Medicare.

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 5

Adjustment to reclassify the amortization of net loss on reacquired debt from interest charges to operation expense.

Amortization of loss on reacquired debt at 6/30/2023	$	837,983
Amortization of gain on reacquired debt at 6/30/2023		-
Amortization of net loss on reacquired debt	$	837,983
Distribution plant allocation		73.96%
Distribution net loss on reacquired debt	$	619,772

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 6

Adjustment to NJBPU and Rate Counsel Assessments based on weather-normalized test year revenues.

	NJBPU	RPA	Total	
Gross revenues from intrastate sales			$ 2,056,789,861	(a)
Assessment rate	0.2483%	0.0531%		
Total assessment	$ 5,106,819	$ 1,092,149	$ 6,198,968	
Test year accrued amount	4,364,933	990,990	5,355,923	
Adjustment to assessment expense	$ 741,886	$ 101,159	$ 843,045	

(a) Amount will be adjusted to reflect the revenue requirement approved by the BPU.

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 7

Adjustment to include amortization of mandated operations and management audit consultant fees.

Total deferred cost of management audit	$	1,469,584
Total	$	1,469,584
Amortization in years		4
Annual amortization	$	367,396
Expense in test year		-
Adjustment to test year	$	367,396

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 8

Adjustment to reflect amortization of expense associated with various rate and regulatory proceedings

Estimated rate case expense for 2023 case:		
Legal fees and expenses	$	1,000,000
Consultant fees and expenses		378,758
Court reporter fees		3,000
Public notices		65,000
Postage/messenger service		2,000
Total	$	1,448,758
50/50 Sharing	$	724,379
Amortization period in years		4
2023 base rate case annual amortization expense	$	181,095
Less Test Year Amortization	$	156,039
Total annual base rate case amortization	$	25,056

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 9

Adjustment to reflect amortization of the Electric Vehicle (EV) recovery:

Depreciation Actuals	$	5,640
Depreciation Forecast		342,193
EV O&M Actuals		582,214
EV O&M Forecast		1,249,767
Incentive Reg Asset (plus return) Actuals		4,398
Incentive Reg Asset (plus return) Forecast		43,550
Total Estimated Regulatory Asset as of June 30, 2023	$	2,227,762
Amortization 5 years		5
Total Annual EV Amortization	$	445,552

NOTE: The actuals are through December 31, 2022 and the forecast includes January to June 2023

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 10

The adjustment removes the Pension test year O&M expense (inclusive of MTM) and replaces with the 2023 Forecast O&M expense and smoothing of the mark-to-market expense for ratemaking purposes.

Line No.	Description	12 ME June 30 2023 Amount
1	Pension O&M Expense per books (Inclusive of MTM)	$ 8,805,328
2	Remove test year Pension MTM expense for actuarial gains/losses	$ 42,420,383
3	Pension O&M expense during Test Year (Line 1 - Line 2)	$ (33,615,055)
4	Test Year MTM & O&M Pension Expense (Line 1)	$ (8,805,328)
5	2023 Pension O&M (Forecast)	$ (13,189,639)
6	Pension Delayed Recognition	$ 37,608,718
7	Adjustment to remove test year expense and add smoothing and 2023 expense (Lines 4 to 6)	$ 15,613,751
8	Distribution Allocation Percentage based on 2022 Distribution S&W	91.55%
9	Distribution adjustment to remove test year expense and add smoothing and 2023 expense	$ 14,294,389
10	Total requested distribution pension expense	$ 22,355,667

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 10(a)

The adjustment removes the OPEB test year O&M expense (inclusive of MTM) and replaces with the 2023 Forecast O&M expense and smoothing of the mark-to-market expense for ratemaking purposes.

Line No.	Description	12 ME June 30 2023 Amount
1	OPEB expense per books (Inclusive of MTM)	$ (15,104,983)
2	Remove test year OPEB MTM expense for actuarial gains/losses	$ (8,297,689)
3	OPEB O&M expense during Test Year (Line 1 - Line 2)	$ (6,807,294)
4	Test Year MTM O&M OPEB expense (Line 1)	$ 15,104,983
5	2023 OPEB O&M (Forecast)	$ (11,163,086)
6	OPEB Delayed Recognition	$ 1,415,824
7	Adjustment to remove test year expense and add smoothing and 2023 expense (Lines 4 to 6)	$ 5,357,721
8	Distribution allocation percentage based on 2022 distribution S&W	91.55%
9	Distribution adjustment to remove test year expense and add smoothing and 2023 expense	$ 4,904,994
10	Total requested distribution OPEB expense	$ (8,923,618)

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 11

Adjustment to amortize AMI O&M & AMI Investment Regulatory Asset

	2023
AMI O&M Reg Asset:	
Balance as of December 2022 Actuals	$ 5,553,940
Deferral Forecast January-June 2023	7,656,894
Estimated Balance as of June 30, 2023	$ 13,210,834
Amortization period	10
AMI Deferred O&M Amortization	$ 1,321,083
AMI Investment Reg Asset:	
Balance as of December 2022 Actuals	$ 895,574
Deferral Forecast January-June 2023	4,029,237
Estimated Balance as of June 30, 2023	$ 4,924,811
(Includes Return, Depreciation and Cost of Removal)	
Amortization period	10
AMI Investment Amortization	$ 492,481
Adjustment to Amortization Expense	$ 1,813,564

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 12

Adjustment to address the ongoing increased expense associated with new BPU vegetation management standards, the test year level of spending above the amount the BPU approved in the Company's last base rate case, along with increased labor expenses for vegetation management activity and increased expenses for removal of danger and hazard trees

		Vegetation Management Expense	
Vegetation Management Program Expense	$	42,640,000	
Test Year Expense Amount		34,363,342	*
Adjustment Amount	$	8,276,658	

* Amount approved in 2020 Base Rate case per BPU Docket No. ER20020146 was $31 million.

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 13

Adjustment to annualize depreciation expense net of cost of removal.

	Depreciation Expense
Distribution Plant:	
Annualized depreciation expense	$ 116,421,999
General plant allocated to distribution:	
Annualized GP depreciation expense	12,558,974
General Plant unrecovered reserve amortization	2,473,556
Total annualized depreciation expense	131,454,529
Total annualized depreciation expense in test year	120,582,031
Adjustment to depreciation expense (403)	$ 10,872,498
Intangible plant allocated to distribution:	
Annualized IP amortization expense	9,575,009
Test year IP amortization expense	12,450,296
Adjustment to test year amortization expense (404)	$ (2,875,287)
6-month beyond the test Year (AMI)	1,584,462
Total	$ 1,584,462
Total Depreciation and Amortization Adjustment	$ 9,581,673

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 14

Adjustment to net cost of removal allowance, based on accrual method, not included in depreciation rate.

Net average cost of removal/salvage (Distribution)	$	27,430,740
Net cost of removal/salvage accrual test year		23,120,819
Adjustment to the allowance for net COR/Salvage	$	4,309,921

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 15

Adjust amortization of deferred storm damage costs.

	Regulatory Asset Balance @ 12/31/2022
Other Storms	$ 310,198,413
Total December 31, 2022 Balance	$ 310,198,413
Annual Amortization	59,000,000
Less amortization included in test year	29,000,000
Adjustment	$ 30,000,000

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 16

Adjustment to recalculate First Energy Service Company depreciation using JCP&L's depreciation rates.

FIRSTENERGY SERVICE COMPANY

12 Months Ended June 30, 2023

	DESCRIPTION	BALANCE AT July 1, 2022	BALANCE AT June 30, 2023	Depreciation on Beginning Balance	Depreciation on Plant Additions	Total Depreciation Based on JCPL rates	UI Planner FERC 403 SC Depreciation Exp	Difference
SERVICE COMPANY PROPERTY								
Account								
301	ORGANIZATION	$ 49,344	$ 49,344			$ -		
303	MISCELLANEOUS INTANGIBLE PLANT	541,378,570	558,409,360			34,950,746		
304	LAND & LAND RIGHTS	230,947	136,339			0		
305	STRUCTURES AND IMPROVEMENTS	79,782,002	75,643,762	1,044,611	(27,105)	1,017,505		
306	LEASEHOLD IMPROVEMENTS (1)	0	0	0	0	0		
307	EQUIPMENT (2)	161,185,213	158,819,297	8,051,734	(57,008)	7,994,726		
308	OFFICE FURNITURE AND EQUIPMENT	177,607,754	189,186,899	33,074,437	1,196,452	34,270,888		
309	AUTOMOBILES, OTHER VEHICLES AND RELATED GARAGE EQUIPMENT	6,506,648	6,045,104	602,317	(28,293)	574,024		
310	AIRCRAFT AND AIRPORT EQUIPMENT	0		0	0	0		
311	OTHER SERVICE COMPANY PROPERTY	0		0	0	0		
	SUB - TOTAL	$ 966,740,479	$ 988,290,106	$ 42,773,099	$ 1,084,045	$ 78,807,889	$ 65,561,240	$ 13,246,650
	Year 2023 allocation factor from FE Service Company to JCP&L for Depr Expense					15.44%	15.44%	
	2023 annual depreciation expense allocated to JCP&L					$ 12,167,938	$ 10,122,655	$ 2,045,283
	Distribution allocation based upon Salaries and Wages							91.55%
	Distribution Service Company Depreciation							$ 1,872,457

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 17

Adjustment to remove SERP "Supplemental Executive Retirement Plan", EDCP "Executive Deferred Compensation Plan" and CBRP "Cash Balance Retirement Plan" expense.

SERP, EDCP & CBRP:		
JCP&L	$	6,843,277
Service Company		(1,467,349)
Total	$	5,375,928
Salary and wage distribution allocator		91.55%
Adjustment to remove SERP, EDCP & CBRP	$	4,921,662

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 18

Adjustment to remove advertising expenses relating to promotional, institutional or civic memberships and other O&M expenses.

		Amount
Informational or instructional advertising	$	298,108
12 Months-ending June 2023 TY Expense	$	773,089
Adjustment to remove advertising expense	$	(474,981)
Other O&M Expenses		
FERC 588	$	(20)
FERC 590		(122)
FERC 903		(310)
FERC 905		(513)
FERC 908		(37,687)
FERC 910		(35,320)
FERC 923		(218,396)
FERC 930.1		1,310
FERC 930.2		(5,122)
Total	$	(296,180)
S&W Allocator		91.55%
Remove Distribution O&M Expense	$	(271,153)
Total O&M removed	$	(746,134)

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 19

Adjustment to reflect amortization of expense associated with ARAM over recovery.

ARAM over recovery concerning TCJA:	
ARAM over recovery	$ (568,439)
Amortization period in years	4
Total Annual ARAM Amortization	$ (142,110)
Amount in Test Year	95,081
Adjustment Amount	$ (237,191)

NOTE: ARAM over recovery per BPU order.

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 20

BGS Administrative Labor to be included in BGS Reconciliation Filing

Total BGS Test Year Labor		
July to December 2022 (Actuals)	$	(51,430)
January to June 2023 (Forecast)		(51,430)
Remove BGS Labor from Income Statement	$	(102,860)

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 21

Adjustment relating to VOSA regulatory asset

VOSA Regulatory Asset	$	10,581
Company not seeking recovery at this time		(10,581)
Adjustment Amount	$	-

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 22

Adjustment for the Low Income O&M and Senior Citizen Discount

	6/30/2023
Total Annual Low Income O&M	$ 637,697
Senior Citizen Discount:	
Annual Discount	$ 1,855,056
Administrative Cost (Materials)	2,500
Administrative Cost (Postage)	9,000
Senior Citizen Discount Expense	$ 1,866,556
TOTAL Annual Low Income O&M & Senior Citizen Discount	$ 2,504,253

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 23

Adjustment for Contract Labor & Fuel Costs

	Adjustment	Capitalization %	O&M Adjustment
Traffic Control	$ 63,915	80.00%	$ 12,783
Underground Locating	41,286	3.00%	40,047
Pole Inspections	6,507	0.00%	6,507
Transportation Fuel	53,258	58.46%	22,123
Adjustment Amount	$ 164,966		$ 81,460

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 24

Adjustment for the A&G Capitalization Regulatory Asset Amortization

	Plant	Reserve	Depreciation Rates	Amortization
36110 - Structures, Improvements	$ 2,615,804	$ 253,708	0.71	$ 18,572
36200 - Station Equipment	4,359,004	422,782	1.25	54,488
36400 - Poles, Towers And Fixtures	6,022,961	584,170	2.15	129,494
36500 - Overhd Conductr, Devices	17,505,162	1,697,835	1.93	337,850
36600 - Underground Conduit	285,940	27,733	1.27	3,631
36700 - Undergrnd Conductr,Devices	8,412,469	815,930	1.61	135,441
36800 - Line Transformers	7,301,652	708,191	2.42	176,700
36900 - Services	2,080,266	201,766	1.21	25,171
37000 - Meters	3,680,534	356,977	4.77	175,561
37100 - Inst. On Cust. Prem.	188,612	18,294	3.71	6,997
37310 - Street Light - Oh, Ug Lines	3,306,470	320,696	3.21	106,138
TOTAL DISTRIBUTION	$ 55,758,874	$ 5,408,082		$ 1,170,043
39010 - Structures, Improvements	$ 882,696	$ 85,613	1.41	$ 12,446
39110 - Office Furn., Mech. Equip.	672,822	65,257	4.00	26,913
39200 - Transportation Equipment	530,273	51,431	3.99	21,158
39400 - Tools, Shop, Garage Equip.	400,299	38,825	4.00	16,012
39600 - Power Operated Equipment	732	71	2.98	22
39700 - Communication Equipment	2,570,228	249,288	5.00	128,511
TOTAL GENERAL	$ 5,057,049	$ 490,486		$ 205,062
GRAND TOTAL				$ 1,375,105

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 25

Adjustment to include investment tax credit amortization.

Investment Tax Credit:		
FERC Account 411.40	$	(131,199)
Distribution plant allocator		73.96%
Adjustment for distribution investment tax credit	$	(97,035)

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 26

Income taxes associated with synchronized interest on outstanding debt

Synchronized Cost of Debt at end of test year (a)		$	65,698,964
State Corporate Business Tax	9.00%		(5,912,907)
Federal Income Tax	21.00%		(12,555,072)
Tax Adjustment		$	(18,467,979)

(a) Rate Base at end of test year		$	2,987,495,270
Weighted cost of debt			
Cost of Debt	4.572%		
Long Term Debt capitalization ratio	48.1%		2.20%
Total synchronized cost of debt		$	65,698,964

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 27

Effect of Applicable Adjustments on Income Taxes.

Adjustment No.			Effect on Taxable Income
1	Revenue Normalization Adjustment		$ (14,766,262)
2	Tariff Fee Adjustments		121,324
3	Interest on Customer Deposits		(517,477)
4	Annualize Payroll Wage Rate Increases		(5,227,469)
4 (a)	Savings Plan match on Payroll Wage Increase		(156,824)
4 (b)	FICA tax on Payroll Wage Increase		(399,901)
5	Reclass Amortization of Net Loss on Reacquired Debt		(619,772)
6	BPU & Ratepayer Advocate Assessments		(843,045)
7	Management Audit		(367,396)
8	Rate Case Expenses		(25,056)
9	EV Regulatory Asset Recovery		(445,552)
10(a)	Pension Smoothing		(14,294,389)
10(b)	OPEB Smoothing		(4,904,994)
11	AMI Regulatory Asset Recovery		(1,813,564)
12	Normalize Vegetation Management Expense		(8,276,658)
13	Annualize Depreciation Expense		(9,581,673)
14	Average Net Salvage		(4,309,921)
15	Storm Damage Cost Amortization		(30,000,000)
16	Service Company depreciation expense at JCP&L Rates		(1,872,457)
17	SERP/EDCP/CBRP		(4,921,662)
18	Remove Advertising & Other Expenses		746,134
19	ARAM		237,191
20	BGS Adminstrative Labor		102,860
21	VOSA		-
22	Low Income Program & Senior Citizen Discount		(2,504,253)
23	Contract Labor and Fuel Costs		(81,460)
24	A&G Capitalization Regulatory Asset Amortization		(1,375,105)
	Taxable income for State income taxes		$ (106,097,382)
	New Jersey Corporate Business Tax at	9.00%	$ (9,548,764)
	Taxable income for Federal income taxes		$ (96,548,618)
	Federal income tax at	21.00%	$ (20,275,210)
	Total income taxes		$ (29,823,974)

JERSEY CENTRAL POWER & LIGHT COMPANY
Normalization Adjustment No. 27

Base Rate ARAM Amortization

			Amount
Grossed-Up For Tax	Protected Property	$	(10,054,771)
Net of Tax	Protected Property		(7,088,447)
Grossed-Up For Tax	NOL		604,798
Net of Tax	NOL		434,789
ARAM Net of Tax Amount		$	(6,653,658)

JERSEY CENTRAL POWER & LIGHT COMPANY
Explanation of Adjustments Under Proposed Rates

			Additional Revenues To Achieve Return
Rate Base		$ 2,987,495,270	
Rate of Return (A)		7.60%	
Return Required		$ 227,049,641	
Normalized Income		94,086,848	
Income Deficiency		$ 132,962,793	
Tax Gross-up Factor		1.391014049	
Revenue Deficiency		$ 184,953,113	
Proposed Increase in Revenues			$ 184,953,113
State Corporate Business Tax	9.00%		16,645,780
Federal Income Tax	21.00%		35,344,540
Total Tax	28.11%		51,990,320
Effect on Operating Income			$ 132,962,793

(A) Required Rate of Return	Capitalization Ratio	Embedded Cost	Rate of Return
Long Term Debt	48.10%	4.572%	2.20%
Common Equity	51.90%	10.40%	5.40%
Total Rate of Return	100.00%		7.60%

JERSEY CENTRAL POWER & LIGHT COMPANY
Actual and Pro Forma Rates of Return for Test Year
Adjusted to Reflect the annualized Effect of Proposed Rates
and of Known Major Changes

Present Rates	
Actual plus forecast (6+6)	
Operating Income	$ 145,141,585
Net Investment in Rate Base	$ 2,987,495,270
Rate of return	4.86%
Pro Forma	
Operating Income	$ 94,086,848
Net Investment in Rate Base	$ 2,987,495,270
Rate of return	3.15%
Proposed Rates	
Pro Forma	
Operating Income	$ 227,049,641
Net Investment in Rate Base	$ 2,987,495,270
Rate of return	7.60%

Exhibit JC-3
Schedule CAP-5 (6+6)

JERSEY CENTRAL POWER & LIGHT COMPANY
Distribution Rate Base at End of Test Year

Line No.		Balance at 6/30/2023 (1)	Balance at 6/30/2023 (a) (2)	Balance 12/31/2023 (b) (3)	Total Rate Base (4) (Sum 1 to 3)
1	Total Electric Utility Plant in Service	$ 6,062,034,051	$ (68,892,010)	$ 45,337,849	$ 6,038,479,890
	Deductions:				
2	Accumulated Provision for Depreciation	2,023,407,484	(17,353,447)	1,584,462	2,007,638,499
3	Accumulated Deferred Income Tax	1,196,729,137	(15,448,813)	32,525	1,181,312,849
4	Customer Advances for Construction (Net of Deferred Tax)	49,827,476			49,827,476
5	Customer Deposits	36,962,658			36,962,658
6	Customer Refunds	278,071			278,071
7	Consolidated Tax Adjustment	964,275			964,275
8	Operating Reserves	9,351,760			9,351,760
9	Total Deductions	$ 3,317,520,861	$ (32,802,260)	$ 1,616,988	$ 3,286,335,588
	Additions:				
10	Unamortized Net Loss on Reacquired Debt	1,371,332			1,371,332
11	Net Operating Loss	36,093,727			36,093,727
12	Deferred Tax Asset for AMT	9,517,218			9,517,218
13	Regulatory Asset A&G Capitalization	54,917,355			54,917,355
14	Total Additions	$ 101,899,632	$ -	$ -	$ 101,899,632
	Working Capital:				
15	Materials & Supplies Inventory	26,179,976			26,179,976
16	Cash Working Capital	107,271,360			107,271,360
17	Total Working Capital	$ 133,451,336	$ -	$ -	$ 133,451,336
18	Total Net Rate Base Investment	$ 2,979,864,158	$ (36,089,750)	$ 43,720,862	$ 2,987,495,270

(a) Pension & OPEB Delayed Recognition
(b) AMI Project forecast to be in service through 12/31/23 (six months beyond the test year)

EXHIBIT JC-4

BEFORE THE
NEW JERSEY BOARD OF PUBLIC UTILITIES

In the Matter of the Verified Petition of Jersey Central Power & Light Company for Review and Approval of Increases in, and Other Adjustments to, Its Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith

Direct Testimony
of
Tracy M. Ashton

Re: Pension/OPEB Expense, OPEB Accounting and Ratemaking Adjustments, and Service Company Relationships, Charges and Allocations

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Tracy M. Ashton, and my business address is 76 South Main Street, Akron, Ohio 44308.

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

A. I am Assistant Controller, Corporate of FirstEnergy Corp. ("FirstEnergy") and a number of its subsidiaries. I am also the Controller of Jersey Central Power & Light Company ("JCP&L" or "Company").

Q. Please briefly describe your educational background and professional qualifications.

A. I have been Assistant Controller – Corporate since May 2019. From May 2008 to May 2019, I served in various positions within the finance organization including Manager of Financial Reporting and Technical Accounting and Director of Business Planning and Performance, prior to being promoted into my current role. I was named as Controller of JCP&L in 2023. From 2003 to 2008, I was with Deloitte & Touche, LLP where I served in various client service positions.

I received a Bachelor of Business Administration degree in Accounting from Kent State University. I am a licensed certified public accountant in Ohio.

Q. Have you previously submitted testimony before any regulatory body?

A. In addition to this testimony, I have provided expert testimony before the Public Utilities Commission of Ohio for the Ohio Significantly Excessive Earnings Test, Docket # 19-1338-EL-UNC. I also provided pre-filed testimony in JCP&L's 2020 base rate case proceeding in BPU Docket No. ER20020146.

Q. Please describe your duties as assistant controller, corporate.

A. I am responsible for ensuring the accounting records of FirstEnergy and its subsidiaries are maintained in conformity with generally accepted accounting principles ("GAAP") and regulatory requirements, including the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts ("USofA"). In addition, I am responsible for disbursements to vendors; external financial reporting; accounting research in connection with proposed business transactions; and cost analysis and accounting classification of construction projects.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is two-fold. The first section explains and supports the level of pension and other post-employment benefits ("OPEB") expense JCP&L is requesting for recovery in its base rate case filed with the New Jersey Board of Public Utilities ("Board" or "BPU"), including the impact of certain accounting adjustments and to propose a mechanism to normalize pension and OPEB expense. The second section of my testimony explains the services provided and costs charged to JCP&L in the test year by the FirstEnergy Service Company ("FESC") under the FESC Service Agreement.

Q. Please summarize your testimony.

A. The first part of my testimony discusses the following adjustments to pension and OPEB expense: (1) remove the 2022 pension mark-to-market loss of $42.4 million and the 2022 OPEB mark-to-market gain of $8.3 million, recognized by JCP&L under GAAP and FERC USofA; and (2) include, for ratemaking purposes, the recalculated amount of the test-year pension and OPEB expense by amortizing the net accumulated actuarial loss over future

periods, consistent with the Delayed Recognition Methodology, as applied for ratemaking purposes in the 2016 and 2020 base rate cases. Based on these adjustments, JCP&L calculated test year expense of $3.7 million of annual pension expense and $4.9 million of annual OPEB credit. However, as discussed herein, JCP&L is requesting that test year pension and OPEB expense be adjusted to reflect 2023 calendar year expense, calculated using the delayed recognition methodology, for purposes of setting JCP&L's base rates, as the 2023 expenses for both pension and OPEB are more reflective of the expense JCP&L will incur in the near-term going forward.

To support the proposed level of pension and OPEB expense to be recovered in base rates, my testimony will provide background on the accounting for pension and OPEB costs under GAAP, including the two accounting methods prescribed by GAAP for the accounting of actuarial gains and losses – one of the components of pension and OPEB costs. I also will provide support for the adjustments necessary to determine the appropriate level of test year pension and OPEB expense for JCP&L, as well as the adjustments associated with the capitalized pension and OPEB costs in rate base. In addition, I will summarize an accounting adjustment related to certain OPEB assets that was recorded as of December 31, 2022, and its corresponding impact on test year expense.

Lastly, with respect to pension and OPEB expense, year-to-year fluctuations in annual earnings, and in some years losses, on the pension and OPEB assets are becoming more material with respect to the Company's income statement and financial performance. These year-to-year market fluctuations also can materially impact test year pension and OPEB expense and customer rates. Therefore, JCP&L is seeking to implement a mechanism to defer the annual difference between the annual pension and OPEB expense,

calculated using the delayed recognition method for ratemaking purposes, and the approved pension and OPEB expense for rate treatment in future base rate cases.

The second part of my testimony discusses the services provided and costs charged to JCP&L under the FESC Service Agreement. I will discuss the process for charging the FESC costs for those services to JCP&L and its affiliates within the FirstEnergy system. In this regard, I will also review the manner by which FESC fairly and equitably charges the costs for its services directly and/or indirectly to JCP&L, FirstEnergy, and its affiliates that receive such services, including the cost allocation methodologies for charging indirect costs. I will also describe the controls in place to ensure proper allocation of costs to JCP&L by FESC, including the reinforcement of direct charging policies, training employees on time charging, enhanced procedures on invoice processing and review of detailed items billed to JCP&L by FESC.

II. JCP&L'S PENSION ACCOUNTING AND RATEMAKING BACKGROUND

Q. How are pension and OPEB costs derived under GAAP?

A. Pension and OPEB costs or credits generally consist of five components:

1. Service cost – Represents the actuarial present value of benefits attributed by the pension and OPEB plans' benefit formula to services performed by employees during the reporting period.
2. Interest cost – Annual interest on the present value of the benefit obligations (liability) at the beginning of the year.

3. Estimated return on plan assets – Represents the estimated return on plan investments by applying the expected long-term rate of return to beginning-of-year plan asset balances.
4. Prior service cost amortization – Represents amortization, over the average remaining service period of employees, of changes to the benefit obligations due to plan amendments.
5. Actuarial gains and losses – Represents the net gain or loss resulting from a change in the value of plan assets and benefit obligations due to experience which differs from assumptions used to estimate the value of end-of-year plan asset and benefit obligation balances. Such differences can be related to the return on plan assets, changes in the discount rate used to calculate the present value of benefit obligations, and other actuarial assumptions such as mortality rates. As further described below, companies either recognize actuarial gains and losses immediately in earnings ("mark-to-market accounting") or through delayed recognition whereby actuarial gains and losses are recorded in accumulated other comprehensive income ("AOCI"), a component of equity, and amortized into earnings over a future period.

As noted in the description of cost component 5. above, companies have the option to recognize the earnings effect of actuarial gains and losses immediately or through delayed recognition. For companies that apply immediate recognition, the full amount of actuarial gains and losses are recognized in earnings immediately. For companies that apply delayed recognition, actuarial gains and losses are captured in AOCI and amortized over a future period. Therefore, the difference in the two "options" is simply a matter of

timing with respect to earnings recognition, with the delayed recognition method producing a less volatile level of gains or losses.

Q. What are actuarial gains and losses under GAAP?

A. Actuarial gains and losses represent the net gain or loss resulting from a change in the value of plan assets and benefit obligations due to experience which differs from assumptions used to estimate the end-of-year plan asset and benefit obligation balances.

In the case of plan assets, the difference between the actual return on plan investments during the year compared to the estimated return on plan investments (cost component 3, above) represents an actuarial gain (if the actual return is higher than the estimated return) or actuarial loss (if the actual return is lower than the estimated return). This component simply adjusts the expected return on plan assets in a given year to the actual return on plan assets in that year.

In the case of benefit obligations, a change in the assumed discount rate that measures the benefit obligation at the beginning of the year to the end of the year will result in an actuarial gain (if the actual discount rate is higher at the end of the year than the assumed discount rate at the beginning of the year) or an actuarial loss (if the actual discount rate at the end of the year is lower than the assumed discount rate at the beginning of the year). The present value of benefit obligations may also be affected by changes in assumed future payouts due to mortality experience that differ from assumed mortality rates, changes in assumed wage increases (in the case of pension costs), changes in assumed health care inflation rates (in the case of OPEB benefits) and other actuarial assumptions. If the present value of benefit obligations increases due to changes in actuarial assumptions, an actuarial loss will be incurred; conversely, if the present value of

benefit obligations decreases due to actuarial assumption changes, an actuarial gain will be recognized. Actuarial gains or losses on plan assets are netted against actuarial gains or losses on benefit obligations to determine the net actuarial gain or loss for the plans for a given year.

Q. Please explain JCP&L's book accounting for pension and OPEB expense.

A. JCP&L's test year pension and OPEB expense is calculated in accordance with GAAP. In December of each year, or whenever a plan is determined to qualify for remeasurement, FirstEnergy and its subsidiaries (including JCP&L) record actuarial gains or losses on their pension and OPEB plans to earnings through a mark-to-market adjustment (immediate recognition).

Q. When are pension/OPEB costs set for the year?

A. FirstEnergy recognizes actuarial gains and losses for its pension and OPEB plans in December of each year, or whenever a plan is determined to qualify for remeasurement. The remaining components of pension and OPEB costs, including service costs, interest cost on obligations, expected return on plan assets and amortization of prior service costs, are set at the beginning of each calendar year and recorded on a monthly basis. Changes in asset performance and discount rates will not impact these costs during the year, however, future years could be impacted by changes in the market. Pension and OPEB expense calculated at the beginning of the year is the monthly cost, net of amounts capitalized.

ADJUSTMENTS TO PENSION AND OPEB EXPENSE

Q. What adjustments have been made to pension and OPEB expense?

A. Effective December 31, 2011, FirstEnergy and its subsidiaries (including JCP&L) adopted mark-to-market accounting (immediate recognition) for their pension and OPEB plans ("Accounting Change"), which is a preferable method of accounting under GAAP. As a result of the Accounting Change, JCP&L records a mark-to-market adjustment for actuarial gains or losses immediately to earnings in December of each year, or whenever a plan is determined to qualify for a remeasurement.

However, for ratemaking purposes in this base rate filing, JCP&L has removed the effect of this mark-to-market adjustment from GAAP pension and OPEB expense and replaced it with actuarial gains or losses calculated under the delayed recognition methodology. This calculation is consistent with the manner in which JCP&L calculated pension/OPEB costs in its 2016 base rate case (BPU Dkt. No. ER16040383) and 2020 base rate case (BPU Dkt. No. ER20020146).

Q. How were the adjustments and test year pension and OPEB expense calculated?

A. There are several steps to the calculation. First, the fiscal year 2022 net actuarial gain recorded by JCP&L is subtracted from the per-books level of expense. Then, under my direction, the Company's actuary calculated the amount of amortization of the accumulated net actuarial loss that would have been included in pension and OPEB expense under the delayed recognition methodology. An adjustment was then made representing the amount of amortization of the accumulated net actuarial loss calculated under the delayed recognition methodology. *See* Schedules TMA-1 and TMA-2.

TEST YEAR AND REQUESTED PENSION AND OPEB EXPENSE

Q. What amount of test year pension expense and OPEB credit has JCP&L calculated?

A. JCP&L calculated a test year distribution pension expense of $3.6 million and a test year OPEB distribution credit of $4.9 million. For the reasons discussed below and detailed in the direct testimony of Carol A. Pittavino, the Company is requesting that test year pension and OPEB expense be adjusted to reflect 2023 calendar year expense, calculated using the delayed recognition methodology, for purposes of setting JCP&L's base rates.

Q. Are there any additional justifications for JCP&L's pension and OPEB expense methodology?

A. JCP&L has included pension and OPEB expense in its income statement for ratemaking purposes using the delayed recognition method. Under this methodology, pension and OPEB mark-to-market expense is amortized over a future period. The effect of the delayed recognition methodology is to amortize the mark-to-market expense over a period of approximately 12 years. Expenses in the income statement have a dollar-for-dollar impact on the Company's revenue requirement. Use of the delayed recognition methodology is designed to reduce the volatility in the level of pension and OPEB costs from year-to-year resulting from JCP&L's election to record actuarial gains and losses on a mark-to-market basis, and instead recognize the impact of actuarial gains and losses on JCP&L's pension and OPEB costs over future periods (delayed recognition). The adjustment is beneficial to JCP&L's ratepayers because reducing the volatility of actuarial gains and losses lessens the fluctuation of retail rates.

Q. Is JCP&L proposing any other adjustments related to pension and OPEB costs?

A. Yes. With respect to capitalized pension and OPEB costs, JCP&L had previously included the capitalized portion of pension and OPEB costs in rate base in the year the expense occurred using the immediate recognition method. To properly reflect pension and OPEB expense in the income statement, JCP&L proposes to adjust the pension and OPEB costs recognized in rate base to eliminate the timing differences between the recognition of pension and OPEB cost in rate base and the recognition of pension and OPEB expense in the income statement. JCP&L has calculated a reduction to rate base of $36.1 million, as described further below. This consists of a reduction to capitalized pension costs in rate base of $35 million, and a reduction to capitalized OPEB costs in rate base of $1.1 million.

There is also a second adjustment to reflect an accounting adjustment made by JCP&L and certain FirstEnergy subsidiaries that reallocated certain OPEB assets as of December 31, 2022, as described later in my testimony.

Q. Do the rate base adjustments follow the Financial Accounting Standards Board ("FASB") Accounting of Net Periodic Pension Cost and Net Periodic Post-Retirement Benefit Cost, as amended on January 1, 2018?

A. Yes. JCP&L (and FirstEnergy) adopted the FASB Accounting Standards Update ("ASU") 2017-07 on January 1, 2018, which amended certain accounting rules addressing the presentation for pension and OPEB service and non-service costs for income statement purposes. Upon adoption, JCP&L (and FirstEnergy) revised its capitalization policy regarding pension and OPEB costs to only capitalize a portion of service costs. All remaining pension and OPEB cost components are not eligible for any capitalization and

as a result are fully expensed (or credited) in earnings. This practice is consistent with the FASB's amended accounting rules, as well as the FERC's USofA.

Prior to JCP&L's adoption of ASU 2017-07 on January 1, 2018, all pension and OPEB costs or credits (including the mark-to-market adjustment) were subject to capitalization under JCP&L's then-current capitalization policy – resulting in a portion of each mark-to-market adjustment from 2011 through 2017 being capitalized into rate base. JCP&L has included an adjustment to rate base to address the timing differences between the calculation of pension and OPEB expense and rate base under the immediate and delayed recognition methodologies for the portion of pension/OPEB costs capitalized in rate base during the period 2011-2017. The appropriate rate base adjustment is reflected in this case.

Q. Why is it necessary to make an adjustment to rate base to adjust for the timing differences of the immediate recognition and the delayed recognition methodologies?

A. The difference in the delayed recognition methodology and the immediate recognition methodology is a matter of timing of the recognition of pension and OPEB costs. With the accounting change in 2018, all pension and OPEB costs are to be expensed, except for current period service costs, of which a portion are to be capitalized. Therefore, to properly reflect pension and OPEB expense in the income statement beginning in 2018, JCP&L adjusted the pension and OPEB costs recognized in rate base between 2011 through 2017 to eliminate the timing differences between the recognition of pension and OPEB cost in rate base and the recognition of pension and OPEB expense in the income statement.

Q. Please explain how the adjustment was calculated.

A. First, for the period January 1, 2011 through December 31, 2017, the Company compared the amounts of capitalized actuarial gains and losses as calculated by its actuary under the delayed recognition methodology to the amounts of capitalized actuarial gains and losses actually recorded under the immediate recognition method for regulatory purposes (See Schedule TMA-3, Attachment B for pension and Attachment D for OPEB). Referring to Schedule TMA-3, Attachment B, capitalized actuarial gains and losses under the delayed recognition methodology are shown in Column C. Column D reflects the Company's per books actuarial gains and losses capitalized in rate base using the immediate recognition methodology. The result in Column E is the difference between capitalized actuarial gains and losses under the delayed recognition methodology and the capitalized actuarial gains and losses recorded under immediate recognition.

Schedule TMA-3, Attachment C, calculates annual and cumulative book and tax depreciation for each annual capitalization adjustment. The results from the book and tax depreciation tables are used in the calculation of the associated accumulated deferred income taxes ("ADITs") on the bottom of Schedule TMA-3, Attachment C, for pension and on Schedule TMA-3, Attachment E, for OPEB.

Schedule TMA-3, Attachment A, summarizes the calculation of the decrease to rate base for capitalized pension costs of $35 million. The resulting rate base adjustment at June 30, 2023 on Schedule TMA-3, Attachment A, for capitalized OPEB costs is a decrease to rate base of $1.1 million. The total adjustment results in a decrease to rate base of $36.1 million.

Q. Why does the adjustment only cover the period from January 1, 2011 through December 31, 2017?

A. This adjustment covers the period from the effective date of JCP&L's accounting election to report pension and OPEB expense for GAAP purposes using the immediate recognition methodology, which began on January 1, 2011, through the adoption of the FASB Accounting Standards Update 2017-07 on January 1, 2018. This is the period JCP&L capitalized pension and OPEB actuarial gains/losses using the immediate recognition method.

Q. Has JCP&L proposed a similar adjustment in prior base rate cases?

A. Yes. As set forth above, JCP&L made the change to its capitalization policy in 2018 in accordance with the FASB amended accounting rules. Accordingly, JCP&L made a similar adjustment in its base rate case filed in 2020.

Q. Why does this calculation have to be made in this base rate case?

A. The calculation should be made until the rate base adjustment is $0 or is otherwise determined to be immaterial.

Q. Have there been any other adjustments to pension or OPEB assets or liabilities on JCP&L's books since the last base rate case?

A. Yes. There was an accounting adjustment to JCP&L's OPEB assets that resulted in better alignment between book accounting with JCP&L's Voluntary Employee Benefit Association ("VEBA") trust.

Q. What were the circumstances that necessitated this change?

A. After the merger of GPU, Inc. ("GPU"), the former parent of JCP&L, and FirstEnergy, OPEB assets were reallocated to reflect changes resulting from the merging of legacy GPU assets into one FirstEnergy plan. This reallocation was to cause the OPEB assets from GPU Service Company to follow the movement (i.e., reassignment) of the GPU Service Company employees to FESC and the various FirstEnergy operating companies post-merger; thus, distributing the OPEB assets from GPU Service Company to align the assets with the liabilities associated with the employees that were to receive benefits. At the time, FirstEnergy OPEB assets consisted of multiple VEBA accounts, some dedicated to specific companies, as well as other VEBA accounts and a 401(h) account that were available to pay benefits more broadly across various operating companies and FESC. Because the Internal Revenue Code does not permit withdrawals from the VEBA accounts for purposes other than benefits payments, the requisite amounts could not be simply transferred from one VEBA account to another. Therefore, in 2003 a reallocation was accomplished through cash transactions among the participating legal entities, including the various operating companies and FESC. This reallocation did not transfer the OPEB assets based on individual VEBA trusts or other accounts. In other words, each of the operating companies and FESC had an investment reflecting a portion of the aggregate OPEB assets based on how the reallocation was determined and transacted through the money pool in 2003.

Guidance in Accounting Standards Codification ("ASC") 715, Defined Benefit Plans, does not prescribe a methodology by which assets at the subsidiary level are to be allocated. Since 2003, the VEBA asset accounts have been rolled-forward each year

following benefit payments, contributions, and a proportional allocation of the investment return for the overall portfolio of OPEB assets to each participating company. However, the individual VEBA trusts were invested differently and earned different returns annually. As a result, the actual returns have been allocated across various FirstEnergy companies since the companies had a percentage ownership in the aggregated OPEB asset over time and in some cases, this created differences between the dedicated VEBA account balance and the allocated VEBA account balance recorded on the books of each participating company, due to the proportional share of investment returns allocated.

Today, most of the generally available assets have been used to pay benefits and the remaining OPEB assets are largely contained in VEBA accounts that are for the benefit of specific operating companies, such as in the case of JCP&L. To capture investment returns in a manner more aligned with the performance of the individual VEBA trusts, FirstEnergy has reallocated its OPEB assets on the books of its subsidiaries as of December 31, 2022. Going forward, FirstEnergy has reallocated the OPEB asset balances between subsidiary companies associated with each specific VEBA account on the books of each participating company, including JCP&L.

Q. What is the financial impact to JCP&L resulting from the OPEB accounting adjustment?

A. The adjustment resulted in an increase of approximately $202 million in OPEB assets at JCP&L as of December 31, 2022.

Q. What is the impact of the OPEB accounting adjustment on pension/OPEB expense in the test year?

A. The adjustment resulted in a higher OPEB asset balance on which JCP&L is expected to earn a return. Therefore, OPEB expense decreased by approximately $6 million in the test year as a result of the reallocation of assets as of December 31, 2022 described above.

Q. Does the Company expect ongoing pension/OPEB expense to align with the test year expense?

A. No. As explained in the testimony of Carol Pittavino, ongoing pension/OPEB expense is not expected to align with test year expense because of the above-referenced OPEB adjustment. Ongoing pension/OPEB expense is anticipated to be more in line with pension/OPEB expense for the 2023 calendar year understanding, however, that pension/OPEB expense may vary materially as it is still subject to market fluctuations as described further below.

Q. What is the forecasted pension/OPEB expense for the 2023 calendar year?

A. Using the delayed recognition methodology, the pension expense for calendar year 2023 is $22.3 million and the OPEB credit for calendar year 2023 is $8.9 million. It is on the basis of these amounts that the Company is requesting to recover annual pension and OPEB expense in this filing. The increase in pension expense is the result of losses of 19.5% on qualified pension plan assets during 2022, which lowers the asset base on which JCP&L will earn a return. Because of the significant change in pension plan asset values in 2022, the 2023 expense (versus 2022) is more reflective of pension expense JCP&L will incur in the near-term going forward. Similarly, for OPEB, due to the accounting adjustment at

year-end 2022, the 2023 expense (i.e., credit) (versus 2022) is more reflective of OPEB expense (i.e., credit) JCP&L will incur in the near-term going forward. In aggregate, the pension and OPEB expense of $13.4 million is lower than the expense included in current base rates by $2.8 million. Please see the Direct Testimony of Carol A. Pittavino (Exhibit JC-3) for an explanation of the pro forma adjustment to test year pension/OPEB expense. Ms. Pittavino's Schedule CAP-2, Adjustments No. 10 and 10(a), provides the detailed calculations of the adjustments and proposed pension and OPEB expense, respectively, to be recovered in base rates.

NORMALIZATION OF PENSION AND OPEB EXPENSE

Q. Why is JCP&L seeking approval of a mechanism to normalize pension/OPEB expense ("PON Mechanism")?

A. FirstEnergy has a qualified pension plan with total qualified Projected Benefit Obligation for both active employees and retirees of approximately $8.4 billion and qualified pension assets totaling $6.7 billion, as of year-end 2022. Over the past 10 years, FirstEnergy has contributed $3.4 billion to this qualified pension plan, achieving a funded ratio of approximately 79% for FirstEnergy's qualified pension plan as of December 31, 2022.

JCP&L's portion of the qualified pension plan's Projected Benefit Obligation for both active employees and retirees is approximately $882 million and JCP&L's portion of the qualified pension assets is $819 million, as of year-end 2022. Over the past 10 years, JCP&L has contributed $282 million to the qualified pension plan, achieving a funding ratio of approximately 93%. JCP&L also maintains an OPEB plan with a Projected Benefit Obligation for both active employees and retirees of approximately $150 million and assets totaling $294 million, as of year-end 2022. The funded ratio was 196% at the end of 2022.

The Company asserts that these benefit plans are an important part of the total compensation package which attracts and retains a skilled workforce. However, the annual fluctuations in investment performance have become significant in the context of JCP&L's income statement and overall financial performance. Therefore, the Company is seeking to moderate the impacts to its income statement from the impacts of the investment performance of pension/OPEB assets due to market fluctuations, which are outside of the Company's control. The PON Mechanism also may moderate the impacts on customers' rates from market fluctuations as well.

Q. How does the PON Mechanism work?

A. As it does today, JCP&L will calculate 2023 pension and OPEB expense under the Delayed Recognition Methodology and include this amount in its base rate case filings. The pension/OPEB expense ultimately approved by the BPU sets the expense included in base rates ("Approved Pension/OPEB Expense"). For each calendar year following the conclusion of the base rate case (i.e., on or after the rate effective date), JCP&L will calculate the annual pension/OPEB expense ("Annual Expense") under the Delayed Recognition Methodology and compare that expense to the Approved Pension/OPEB Expense from its most recent base rate case. To the extent that the Annual Expense is less than the Approved Pension/OPEB Expense, customers will be provided the benefit of the reduction in the Annual Expense and the Company will defer a regulatory liability for 100% of the difference between Annual Expense and Approved Pension/OPEB Expense. To the extent that the Annual Expense is greater than the Approved Pension/OPEB Expense, the Company will defer a regulatory asset for 90% of the difference between the Annual Expense and the Approved Pension/OPEB Expense. Therefore, when the Annual

Expense is greater than the Approved Pension/OPEB Expense, customers will also benefit from a 10% reduction in the amount deferred. The net amounts deferred for each calendar year will accumulate until the next base rate case, where the Company will request and the BPU will decide on an appropriate amortization and recovery or refund period for the regulatory asset or liability.

Q. Will the recovery of amounts related to the PON Mechanism deferral be in addition to Approved Pension/OPEB Expense (i.e., the pension/OPEB expense recovered under the Delayed Recognition Methodology)?

A. Yes. The Company would recover its pension/OPEB expense and, in addition, seek to refund, or recover, the PON Mechanism deferral balance at its next base rate case. The Company would provide a credit to customers, in the instance where the deferred amount is a regulatory liability, or collect from customers, in the instance where the deferred amount is a regulatory asset, the amortization of the PON Mechanism deferral through future base rates.

Q. How does the proposed PON Mechanism benefit customers?

A. Fluctuations in pension and OPEB costs are expected to normalize or offset over the long-term. However, in the short-term, market trends or corrections result in pension and OPEB costs that may not be representative of the actual long-term cost of providing these benefits to active employees and retirees. Often after a correction in the markets, for example the events that occurred in 2022, there is some near-term rebound. As this rebound occurs, pension and OPEB expense will decrease as market performance of the pension and OPEB assets improves. Using this scenario as an example, should pension and OPEB expense be

set for ratemaking purposes at the time of one of these market correction events, the cost that customers would be paying for pension and OPEB expense would not reflect the near-term recovery in the markets and, for this period, would be greater than the amount that would need to be recovered to compensate the Company for its pension and OPEB expense. Again, because of the size of the pension and OPEB assets, these amounts year-to-year can be material. The PON Mechanism would accumulate the changes in Annual Expense as compared to the Approved Pension/OPEB Expense and ensure that customers were credited for any reductions in pension and OPEB expense as compared to Approved Pension/OPEB Expense and only paid 90% of any increases in pension and OPEB expense as compared to Approved Pension/OPEB Expense – the result being that customers pay less than the Company's cost to provide these benefits to its employees.

Q. How does the proposed PON Mechanism benefit the Company?

A. Under the PON Mechanism, JCP&L would defer credits or expenses in a regulatory asset on its books, based on the difference between Approved Pension/OPEB Expense and the Annual Expense in each calendar year following the conclusion of the base rate case and the effective date of base rates implemented as a result of same. In years where the market performance of the pension and OPEB assets was less than expected, the deferral of 90% of the increase in pension and OPEB expense (as compared to the Approved Pension/OPEB Expense) would reduce the volatility on JCP&L's income statement and financial performance.

Q. Doesn't the Delayed Recognition Methodology already provide for smoothing of impacts related to pension/OPEB asset investment performance?

A. For customers, yes. Customers benefit from the smoothing aspects of the Delayed Recognition Methodology. In each base rate case since the Delayed Recognition Methodology has been used to calculate the Company's pension and OPEB expense for ratemaking purposes, the Delayed Recognition Methodology has resulted in lower test year pension and OPEB expense than under the Company's immediate recognition methodology used for book purposes. However, because pension and OPEB expense is reset only during a base rate case proceeding, which in recent history for JCP&L has been approximately every 3 to 4 years, it does not capture fluctuations in pension and OPEB expense between base rate cases, which have become more significant with the growth in pension and OPEB assets over time.

Q. Has the BPU ever considered a deferral mechanism in the past where costs can change materially between base rate cases?

A. While the Company is not seeking clause treatment for pension and OPEB expense in this case, in 1971, the BPU implemented fuel adjustment clauses for the Company (which would eventually be known as the Levelized Energy Adjustment Clause), due to the impacts from highly fluctuating fuel prices for electric generation. In its July 1, 1971 order (Docket No. 698-541), the BPU offered the following analysis:

> Generally, fuel is the largest single item of operating expense of an electric utility. So long as the trend of fuel costs is generally parallel in direction and degree to those of other expenses and of revenues, it does not make a great deal of difference whether an electric utility does or does not have a fuel adjustment clause. When, however, the direction or degree of change of fuel costs departs radically from that of other expenses or revenues, it becomes important in the rate

> regulatory process that provision be made for prompt and automatic adjustment of revenues to match the change in its fuel costs and directly related items such as taxes on gross revenues thereby keeping the utility financially whole.[1]

Even under the Delayed Recognition Methodology, which provides for smoothing of annual impacts of pension and OPEB asset investment performance, JCP&L experienced a change in pension expense for 2022 to 2023 of over $25 million. JCP&L contends that fluctuations in investment performance are significant enough between base rate cases to warrant deferral treatment to mitigate the impacts to JCP&L's income statement and financial performance, and to further mitigate volatility in customers' rates.

In addition, the Board recently approved a pension deferral mechanism for Public Service Electric and Gas Company ("PSE&G") that is designed to mitigate the volatility of its significant pension expense.[2] JCP&L applauds the BPU's recognition that pension and OPEB costs and the impacts on New Jersey utilities and their customers are matters that need to be addressed in the ratemaking process.

Q. Why doesn't JCP&L adopt the same pension and OPEB deferral methodology recently approved for PSE&G?

A. JCP&L has reviewed the PSE&G filing and Board Order and due to differences in accounting methods adopted by PSE&G and JCP&L, the PSE&G approach would not benefit JCP&L. In short, the Immediate Recognition Methodology that FirstEnergy uses for book accounting purposes prescribes that gains and losses be expensed in the year

[1] *I/M/O the Petition of Jersey Central Power & Light Company for Approval of an Increase in Rates for Electric Service and Changes in Tariffs for Such Service*, Order on Motion to Place in Effect Fuel Adjustment Clauses, BPU Docket Nos. 698-540/541 (July 1, 1971). **See also**, *BPU Order Accepting Tariff Revisions Placing in Effect Fuel Adjustment Clauses*, BPU Docket Nos. 698-540/541 (July 15, 1971).

[2] *See I/M/O Public Service Electric and Gas Company's Request for an Accounting Order Authorizing the Company to Modify Its Pension Accounting for Ratemaking Purposes*, BPU Docket No. ER22090549, Order (Feb. 17, 2023).

incurred. As such, JCP&L does not accumulate these gains/losses on its books so there are no amounts to be smoothed. JCP&L customers benefit from the use of the Delayed Recognition Methodology for ratemaking to smooth pension and OPEB expense and spread the gains and losses over future periods, but this does not occur on JCP&L's accounting books. Therefore, any modifications to this regulatory construct do not result in any offsets on JCP&L's books.

Q. Why should the BPU approve the PON Mechanism at this time?

A. This is somewhat of an emerging issue for utilities with large pension and OPEB assets and obligations. Because the Projected Benefit Obligation continues to grow as utilities continue to offer these benefits to its active employees and retirees, the corresponding assets must also continue to increase to satisfy these benefit obligations. As a result, the year-to-year fluctuations in annual earnings, and losses in some years, on the pension and OPEB assets as well as the impact of interest costs and volatility in the discount rate utilized to measure benefit plan obligations, are all becoming more material with respect to the Company's income statement and financial performance. Further, the year-to-year market fluctuations also can materially impact test year pension and OPEB expense and, therefore, customer rates. Because of these increasing impacts, JCP&L requests that the BPU consider a deferral mechanism, such as the proposed PON Mechanism, that provides some offset for the utility to downside market performance of the pension and OPEB assets in years when it occurs and also ensures that customers pay no more than the cost of these benefits, which in the case of the proposed PON Mechanism, will result in costs to customers that are less than the cost of these benefits.

III. FESC RELATIONSHIPS, CHARGES AND ALLOCATIONS

BACKGROUND

Q. Please describe FirstEnergy and its consolidated subsidiaries.

A. FirstEnergy, through its subsidiary companies, primarily owns and operates regulated businesses that are involved in the generation, transmission, and distribution of electricity.

FirstEnergy's regulated business is comprised of ten regulated electric distribution companies that serve customers in New Jersey, Ohio, Pennsylvania, Maryland, West Virginia, and New York. FirstEnergy's wholly-owned regulated electric distribution companies (Jersey Central Power & Light Company, Metropolitan Edison Company, Pennsylvania Electric Company, The Cleveland Electric Illuminating Company, Ohio Edison Company, Pennsylvania Power Company, The Toledo Edison Company, West Penn Power Company, The Potomac Edison Company, and Monongahela Power Company) serve approximately six million customers in the Midwest and Mid-Atlantic regions, covering 65,000 square miles across six states. FirstEnergy also has majority ownership in three regulated independent transmission businesses, which have approximately 24,000 miles of high-voltage lines and two regional transmission operation centers within the PJM Interconnection, LLC ("PJM") region. PJM is the regional transmission organization that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia.[3]

[3] It should be noted that not all of the FirstEnergy transmission assets are part of the three independent transmission businesses. Some of FirstEnergy's distribution utilities, including JCP&L, currently own their own transmission assets for which they are provided with transmission support services through FESC, and the costs for such transmission support services are addressed in proceedings related to transmission rates before the FERC and not as part of this proceeding. However, I should also clarify that the same personnel who provide the transmission support services, which are not addressed in this proceeding, also provide some distribution support services, which are addressed in this proceeding.

Q. In addition to its regulated business, does FirstEnergy also have unregulated businesses?

A. FirstEnergy has limited unregulated business. After completion of the FirstEnergy Solutions and subsidiaries ("FES"), and FirstEnergy Nuclear Operating Company ("FENOC") bankruptcy (filed March 31, 2018, with emergence February 27, 2020) and the transfer of the competitive Pleasants Power Station in 2020, FirstEnergy completed its exit from non-regulated generation production. Upon the completion of FES's and FENOC's emergence from bankruptcy as a fully separate non-affiliated entity (Energy Harbor), the unregulated business now comprises less than 1% of FirstEnergy's gross plant assets.

Q. Please describe the role of FESC within FirstEnergy.

A. FESC is a centralized service provider formed for the purpose of providing administrative, management, operations support, and other services to FirstEnergy and its affiliated companies. It has been long understood[4] that providing the broad array of services described herein throughout a holding company system such as the FirstEnergy System, by and through a centralized mutual service company, such as FESC, is more efficient and less costly than providing, managing, and staffing such services at each individual associate company.

The FirstEnergy System is also able to take advantage of its economies of scale to more efficiently utilize its resources by providing such services from centralized groups

[4] For instance, the predecessor to PUHCA 2005, the Public Utility Holding Company Act of 1935 ("the '35Act"), and the regulations (e.g., Rules 87, 88, 90, 91 and 93) promulgated thereunder, permitted, and regulated, the use of, and charging of costs by, mutual service companies that provided services within registered public utility holding company systems.

within FESC. For instance, among other things, FESC has a greater degree of bargaining power with suppliers than would FirstEnergy and each of its associate companies negotiating individually, because FESC negotiates, where appropriate, on behalf of the overall FirstEnergy System.

Q. Please be more specific about the types of services centrally provided by FESC to FirstEnergy and its associate companies, including JCP&L.

A. FESC provides various corporate, managerial, and administrative support services to FirstEnergy and its associate companies, including JCP&L, in the following areas: administrative services, business development, call centers, claims, communications, controllers, corporate and shareholder services, corporate affairs and community involvement, credit management, energy delivery and customer service, economic development, enterprise risk management, governmental affairs, human resources, industrial relations, information services, insurance services, internal audit, investment services, investor relations, legal, performance planning, rates and regulatory affairs, real estate, supply chain, technologies support, telecommunications support, transmission & distribution technical services, construction and design services, treasury and workforce development.[5]

A full list and description of the services provided by FESC are set forth in Exhibit A to the Service Agreement (as defined below) that is attached hereto as Schedule TMA-4.

[5] Please note that FESC also provides, on a limited basis, goods in connection with such services. However, for the sake of simplicity and clarity, I only refer to "services" in my testimony. Those services have been articulated in the agreement approved by the BPU on December 14, 2005 at Docket No. EM02100777.

Q. Does FESC perform utility operations services for JCP&L or any other of the FirstEnergy utility companies?

A. Although FESC provides utility operations-related ***support*** services, it is important to emphasize that FESC, generally, does not perform the "operations" services, which are, instead, performed by the FirstEnergy utility companies themselves, including JCP&L. One exception to this, however, is in the area of vegetation management, which is centrally managed at FESC for the entities, such as JCP&L.

A. FESC COST ACCOUNTING

Q. Are you familiar with FESC's books and records and how they are maintained?

A. Yes, I am. The books and records of FESC are maintained in accordance with the FERC USofA and GAAP.

Q. Can you please provide an overview of how FESC accounts, and charges, for the costs of its services?

A. Yes. FESC renders services to FirstEnergy and its associate companies at cost. The full costs of the services provided by FESC are either directly or indirectly charged to FirstEnergy and its associate companies (including JCP&L). Some FESC costs are directly charged to a particular company, such as JCP&L, because those costs are related to services performed solely for JCP&L. An example of such a direct charge is the charge for substation engineering, where a group of FESC employees based in New Jersey provide substation engineering services exclusively for JCP&L. Each of those employees effectively directly charges his or her time and expenses to JCP&L.

Other FESC costs are indirectly charged when the costs are not directly chargeable to a single associate company because the services benefit multiple associate companies, and the particular costs of the service is not identified to any individual associate company or companies. One example of such indirectly charged costs is an employee's work associated with the execution of the monthly financial close in the FirstEnergy SAP Enterprise Resource Planning system ("SAP"), which is FirstEnergy's comprehensive system-wide management software system. Such an employee's time would be indirectly charged to FirstEnergy and its associate companies using cost allocation methodologies that I discuss herein.

As I will further explain, the processes for accounting for, and charging, FESC costs, including the cost allocation methodologies for charging indirect charges, are integrated into SAP.

Q. Please further clarify what you mean by "directly charged."

A. When I say that a cost is "directly charged," I am using that terminology to convey that the time and expenses associated with the service are charged directly to the identifiable associate company for which the service is being rendered. The costs of services are charged directly to the associate company receiving the services or for a particular transaction.

Q. Please further clarify what you mean by "indirectly charged."

A. When I say that a cost is "indirectly charged," I am using that terminology to convey that the charges are not specifically directly charged to a single associate company. In such cases, one could also say that such cost is "allocated" or "charged on an allocated basis." While these terms can be used interchangeably, I have attempted to be consistent in using the term "indirectly charged" to simplify the distinction between such charges and those that are directly charged.

For instance, it is sometimes said that one cost is "directly charged" while another cost is "indirectly allocated." This combination of terms may create confusion that I am hoping and attempting to avoid.

Q. Are the terms "directly charged" and "indirectly charged" the same as "direct costs" and "indirect costs"?

A. No. The former terms are methods of charging. The latter terms are types of costs. Since I have explained the former terms, I will also explain the latter terms.

Direct costs are costs that can be specifically identified with a particular service performed for an associate company. Costs incidental or related to direct items are also classified as direct costs. Direct costs may be directly charged if reasonably identifiable to a particular recipient associate company. For example, FirstEnergy Corp.'s Board of Director fees are directly charged to FirstEnergy Corp., with no other affiliate bearing the expense.

Indirect costs are costs of a general overhead nature such as support costs that cannot be identified with a particular service. This includes but is not limited to overhead costs (i.e., payroll, stores handling, construction), administrative and general expenses, and various payroll taxes. Costs incidental or related to indirect items are also classified as indirect costs. Indirect costs may be directly charged if reasonably identifiable to a particular recipient associate company; otherwise, indirect costs are indirectly charged using an approved cost allocation methodology.

Q. What are the components of the service costs that are charged by FESC, whether charged directly or indirectly?

A. Service costs are fully loaded, meaning that they include the direct costs incurred to provide a service plus the indirect costs (such as appropriate overheads) incidental or related to a service whether charged directly or indirectly.

Q. When a service is provided to a group of companies, does FESC directly or indirectly charge the costs for such service?

A. It depends. If the costs can be reasonably identified and related to the particular transaction for the particular individual associate companies, then the costs are directly charged to each individual associate company in the group. If they cannot, then the costs must be indirectly charged using an appropriate cost allocation methodology. However, I wish to emphasize that whenever practicable (to the extent excessive effort or expense is not required), costs that can be identified as related to a particular service provided to a particular associate company are directly charged to that associate company. But, to repeat, where the costs cannot be so identified, they are indirectly charged using an approved cost allocation methodology.

Q. What do you mean by "cost allocation methodology?"

A. A "cost allocation methodology" is a method or process for distributing costs for services rendered that are not directly charged to a single associate company, such as charges to multiple associate companies, which are indirectly charged.

Q. Where are the FESC cost allocation methodologies found?

A. The cost allocation methodologies used by FESC today are set forth in the FESC (Service Agreement) and are the same ones that were approved by the SEC in 2003 and by the Board in a December 14, 2005 Order in BPU Docket Nos. EM02100777 and EE98050267 (the "December 2005 Order"). The cost allocation methodologies are also listed in the FERC Form

60, which FESC uses to report to the FERC annually, a copy of which is also provided to the Board and the Division of Rate Counsel.

A copy of the FERC Form 60 for 2022 encompassing part of the Test Year is being finalized for filing with FERC and will be filed as a supplement, as schedule TMA-5 as soon as it is filed. As I discuss further below, the FirstEnergy cost allocation methodologies and the procedures for using them are maintained and reviewed annually by the FirstEnergy General Accounting department, which is within the FirstEnergy Controllers Department and reports to me.

Q. How does FESC use cost allocation methodologies?

A. FESC has no earnings, renders services at cost to FirstEnergy and its associate companies and, therefore, all its costs must be fairly and equitably distributed to FirstEnergy and its associated companies. The cost allocation methodologies are used to accurately distribute those costs that are not directly charged to a particular associate company, and, therefore, are indirectly charged to, and among, the FirstEnergy associate companies in compliance with the standards promulgated by FERC under PUHCA 2005 (including cost allocation methodologies previously approved by the SEC under the '35 Act and applicable state requirements, including, in the case of JCP&L, the December 2005 Order). The particular cost allocation methodology used with respect to any particular service varies based on the service provided and the associate company or companies receiving the service.

Q. How many cost allocation methodologies does FESC use?

A. As described in the Service Agreement, FESC has eighteen cost allocation methodologies available, of which eleven are currently in use, to appropriately and accurately distribute the costs

of services, which are to be indirectly charged to and among FirstEnergy and its associate companies.

Q. Does the identity of the recipient associate company play a role in determining the use of a cost allocation methodology?

A. Yes. For example, if a service is being provided only to an unregulated segment of FirstEnergy's business, then the costs that need to be indirectly charged in a general manner would be indirectly charged using the "Multiple Factor-Non-Utility" cost allocation methodology so that such costs are not borne by any of the FirstEnergy utilities in the regulated segment.

Q. Are the cost allocation methodologies grouped together in any way that is helpful to understanding how they work?

A. Yes. Seven of the cost allocation methodologies pertain to information technology services. Four are used as general cost allocation methodologies with respect to costs that are not readily identifiable with particular cost drivers (i.e., a measurable event or quantity that can influence the level of costs incurred for or by a particular activity and which can be directly traced to the origin of the costs themselves). The remaining seven cost allocation methodologies are identifiable to particular cost drivers, an example of which would be, employee headcount for employee benefit costs.

Q. How are the cost allocation methodologies related to the services provided by FESC?

A. The Service Agreement lists the service categories and particular types of services along with a general description of the services and a reference to the cost allocation methodology (or methodologies) that is/are most likely to be used for costs associated with such services that are to be indirectly charged. As discussed later in my testimony, the costs are accumulated and

allocated at the cost center level, which is the lowest level of cost collector in SAP. These cost centers and the associated allocation method are reviewed annually.

Q. Are the cost allocation methodologies changed regularly or periodically?

A. No, they have been approved by the SEC and, with respect to JCP&L, the Board, and accurately reflect the most relevant cost drivers of the organization.

Q. Does any aspect of the cost allocation process change from time to time?

A. While the cost allocation methodologies themselves have not changed, the data inputs required to apply the cost allocation methodologies are updated on an annual basis based on actual experience. For example, the general cost allocation methodology "Multiple Factor–Utility" requires an averaging of three factors related to a FirstEnergy utility's percentage share of all the FirstEnergy utilities' plant, operations and maintenance expenses, and revenues. This data will vary from year to year based upon actual results of operations. As a result, while the methodologies would not change, the percentage share for an associate company and the percentage allocation among associate companies within the methodology can change from year to year based on actual results.

Q. Earlier you referred to SAP. Please explain how FirstEnergy uses SAP.

A. SAP is the FirstEnergy resource planning software system that links and coordinates business processes to perform core business functions such as, for example, maintaining a general ledger, financial reporting, inventory management and purchasing transactions, in a fully integrated enterprise management system. When initially installed (at GPU in 1999 and FirstEnergy in 2003), SAP replaced other software systems that were not fully integrated or which required interfaces to integrate. SAP has been maintained through regular functional enhancements

(multiple releases per year) to support business operations, as well as implementing major version updates that introduce new business functionality, the most recent of which was completed in 2015.

SAP is used to manage work, share information, track customer accounts, and meet other business needs. SAP contains the functions and processes for capturing, reporting, and directly charging and indirectly charging FESC costs to and among FirstEnergy and its associate companies. SAP is currently organized to maintain, among other things, (i) separation of costs between FirstEnergy's regulated and non-regulated associate companies, and (ii) an adequate audit trail on the books and records of FirstEnergy and its associate companies.

Q. Please discuss the role of cost collectors.

A. Attributing and charging costs accurately to FirstEnergy and its associate companies requires the costs to be captured in SAP. This is the job of cost collectors, which are accounting devices used to plan, track, and account for costs of different categories or types of work. Cost collectors include orders, work breakdown structures ("WBS") and cost centers. Only one of these three types of cost collectors can be entered on a document during data entry. Orders (i.e., sales, production, process, purchase, internal, or work order that uniquely identifies a cost source) and WBSs (i.e., a cost collector that organizes in a hierarchy the actions and activities to be carried out in a project) are temporary cost collectors because the costs accumulated using these cost collectors ultimately settle to a cost center or balance sheet account. A cost center is the principal and lowest level of cost collector, where the costs of providing services are accumulated to be either directly charged or indirectly charged.

Q. Please describe the use of cost centers.

A. Cost centers are the principal type of cost collector in SAP. Within SAP, cost centers are assigned to departments and/or managers responsible for certain areas of the business such as functional areas within, for example, human resources, finance, facilities, information systems, administrative support, and legal. Each employee within the FirstEnergy System, including at FESC, is assigned to a cost center that relates to the area of the business or category of service for which they are responsible (e.g., human resources, legal, treasury). The cost center provides the mechanism for collecting the costs associated with those employees and the services they provide, including overheads, incidental and related costs. All employees are required to ensure that their time in providing services is captured (i.e., by recording the time spent on various tasks on a timesheet). In the case of FESC, this also means identifying the appropriate cost center for the associate company, or companies, receiving such services. Ultimately, both the service provider cost center and the service recipient cost center track charges and payments for the costs associated with the services rendered.

Q. Are the descriptions and uses of cost centers reviewed periodically?

A. Yes. As part of FirstEnergy's annual Sarbanes-Oxley ("SOX") internal control reviews, General Accounting performs an annual review of the allocation methodologies used for indirect charges to determine whether: 1) billing allocators are still valid; 2) new allocation factors are needed; and 3) cost centers are using the correct allocation factors. Additional details about this annual review of cost centers are provided in the "Controls" section of my testimony below.

Q. Is employee time charging subject to review?

A. Yes. Supervisory review of employee time charged out of their home cost center is regularly performed to ensure time charged is appropriate and the cost center (or other cost collector) being used is proper. This includes review of the time document charges in relationship to employees' work schedules. In addition, training is provided to all business units to reinforce appropriate time charging.

Q. Besides time charges, are there other sources of costs captured in SAP?

A. Other-than-labor costs are accounted for in SAP based on expense reports, vendor invoices, journal entries, and system interfaces (such as depreciation, taxes). The costs associated with these sources would also flow to appropriate cost centers for tracking, billing, and collection.

Q. How are costs transferred in SAP from FESC to JCP&L?

A. In responding to this question, it may be helpful to recall my earlier discussion of FESC costs that are directly or indirectly charged. FESC costs are accumulated in the cost centers and other relevant cost collectors and are either (i) "directly charged", for those costs originating within FESC that relate to services identified as benefiting only JCP&L (for instance), or (ii) "indirectly charged" using appropriate general and/or specific cost allocation methodologies associated with the services rendered, where the costs are identified as benefiting JCP&L and one or more of FirstEnergy and its other associated companies.

B. FESC COSTS IN THE TEST YEAR

Q. Please summarize the direct and indirect FESC costs to JCP&L in the Test Year.

A. During the Test Year, FESC charges amount to a total of $153,299,226 charged to JCP&L. This total amount includes FESC costs related to transmission, which are recovered through

transmission rates. As explained in Ms. Pittavino's testimony, the transmission-related FESC costs have been removed from JCP&L's request as part of this proceeding. Of the total amount, $41,522,252 are direct charges to JCP&L primarily for services from FESC's Transmission & Distribution ("T&D") group for distribution support services, the information technology group, the corporate services and Chief Information Officer function, and the legal department. The remaining $111,776,974 in costs are indirect charges to JCP&L primarily for services from FESC's customer service function, the information technology group, the T&D group, the corporate controller function, and the human resources group using appropriate cost allocation methodologies found in the Service Agreement.

Q. Are any of the indirect FESC costs allocated to FirstEnergy Corp.?

A. Yes. In accordance with the December 2005 Order, five percent (5%) of the indirect charges from FESC related to products and/or services that benefitted the entire FirstEnergy enterprise are allocated to FirstEnergy as the parent holding company. The remaining indirect charges are allocated to the appropriate FirstEnergy subsidiaries, which may include JCP&L, in accordance with the approved methodologies set forth in the Service Agreement. specific to only FirstEnergy, such as FirstEnergy Corp.'s Board of Director expenses, are directly charged to FirstEnergy, and are not borne by any subsidiary.

Q. Can you provide additional detail regarding the FESC charges that were assigned to JCP&L?

A. Yes. The following table (Table TMA-5) provides a breakdown of Test Year charges by FESC department or function. The description of functional services in the Service Agreement describes the services that are associated with these charges. It should be noted that the ratio of

indirect to direct costs for the Test Year is likely affected by the mix of actual (last six months of 2022) and budgeted (first six months of 2023) data insofar as the budgeted data is not as readily susceptible to a determination as to whether it will be directly charged or indirectly charged -- a determination that is more precisely made at the time of the delivery of the services. As such, the (12+0) update to revenue requirements that the Company will provide in this case will reflect the actual amounts that are directly and indirectly charged during the test year.

Table TMA-5

FirstEnergy Service Company Costs Charged to JCP&L
Test Year - July 1 2022-June 30 2023

Department or Function	Direct	Indirect	Grand Total
President & CEO Support	$ -	$ 2,298,589	$ 2,298,589
Transmission, Distribution Operations Support	20,381,752	26,195,224	46,576,976
Compliance & Regulated Services Support	87,567	2,763,684	2,851,251
Customer Support	3,392,352	17,722,979	21,115,331
SVP & Chief Financial Officer	-	212,751	212,751
Information Technology Support	9,625,096	18,397,987	28,023,083
Supply Chain Support	458,396	7,953,763	8,412,159
Accounting and Tax Support	693,705	10,894,909	11,588,614
Treasury Support	-	664,196	664,196
Risk Support	2,964	2,005,948	2,008,912
Strategy, LT Planning & Business Performance Support	12,222	783,771	795,993
Internal Auditing Support	14,104	933,106	947,210
Legal Support	2,197,789	3,725,728	5,923,517
Rates and Regulatory Affairs Support	2,027,857	429,269	2,457,126
External Affairs Support	484,012	323,366	807,378
Corporate Responsibility and Communications Support	-	8,781	8,781
Corporate Affairs &Community Involvement Support	2,100	645,167	647,267
Human Resources & Corporate Services Support	2,107,580	13,468,349	15,575,929
Investor Relations, Corporate Responsibility and Communications Support	4,200	1,375,581	1,379,781
Ethics & Compliance Support	30,556	973,826	1,004,382
Total	$ 41,522,252	$ 111,776,974	$ 153,299,226

Q. What is the percentage of directly charged costs as compared to indirectly charged costs to JCP&L?

A. The following table (Table TMA-6)[6] provides a perspective on the distribution of costs from FESC to JCP&L for the Test Year as compared to the actual results for 2021 in terms of directly charged, indirectly charged and total costs:

Table TMA-6 ($)

	JC DIRECT	JC INDIRECT	TOTAL	DIRECT %	INDIRECT %
2021	38,856,630	80,244,962	119,101,592	32.62%	67.38%
TEST YEAR	41,522,252	111,776,974	153,299,226	27.09%	72.91%

As mentioned above, the ratio of indirect to direct costs for the Test Year is likely affected by the mix of actual (last six months of 2022) and budgeted (first six months of 2023) data, which is not as readily susceptible to a determination as to whether and the extent to which it will be directly charged or indirectly charged -- a determination, as I stated above, that is made at the time of delivery of the services. For example, actual results for 2021 indicate the ratio of direct and indirect costs was 32.62% direct and 67.38% indirect, which is generally consistent with the ratio of direct and indirect costs in the Test Year.

Q. Can you provide any additional perspective regarding the direct and indirect FESC charges to JCP&L reflected in the Test Year amounts?

A. Yes, I can. I believe it is helpful to consider FESC costs charged to JCP&L in the context of the overall operations and maintenance costs of JCP&L, to understand the relationship of the FESC costs to JCP&L's total cost of operations (which are comprised of JCP&L's own cost of operations together with the FESC's charges). In addition, because costs directly charged by

[6] Table TMA-6 represents all charges to JCP&L on an actual GAAP basis.

FESC to JCP&L are, in essence, functionally equivalent to JCP&L's own (local) cost of operations, this view also provides additional perspective on the ratio of directly charged and indirectly charged costs from FESC. Consistent with FESC's role as a mutual service company, the services that give rise to these FESC costs, particularly the indirectly charged costs, are predominantly shared services that are less likely to be directly charged.

As shown in the table below (Table TMA-7) FESC's total charges to JCP&L during the Test Year represent only 18.5% of JCP&L's total Test Year cost of operations (excluding generation and purchase power expenses). More specifically, FESC's total indirectly charged O&M costs to JCP&L during the Test Year, including transmission-related costs that are not being requested as part of this proceeding, represented only approximately 14.7% of JCP&L's total cost of operations:

Table TMA-7[7]

Cost Category	JCP&L	%
Total T&D Operations & Maintenance	$ 473,178,001	81.5%
Service Company (O&M Direct)	22,168,539	3.8%
Service Company (O&M Indirect)	85,028,578	14.7%
Total Costs	$ 580,375,118	100.0%

The annual cost center review process, which I discussed earlier, encourages the use of the most appropriate charging method given the nature of the costs and whether the cost is identifiable only to JCP&L and the results indicated above are consistent with that encouragement.

[7] The total of these (i.e., $580,375,118) is consistent with, and relies on, the amount set forth in Schedule CAP-1 (column 1, rows 7 to 12) as set forth in the direct testimony of Carol A. Pittavino, Exhibit JC-3.

Q. Can you explain the increase in FESC O&M Indirect costs since the last rate case?

A. Costs indirectly billed by FESC have increased in part due to expansion in departments to support FirstEnergy's mission and strategy, including but not limited to, creating a new Office of Ethics and Compliance to oversee organization-wide compliance, assurance, training and communications, creation of an Innovation Center and Digital Factory and build out of our customer support organization to enhance the customer experience, expand communication channels and improve customer satisfaction as well as creation of a new Organizational Performance Management and Strategy department. As part of an effort to gain efficiencies across the FirstEnergy operating companies, certain services were centralized from the operating companies to FESC increasing the indirect costs. Examples of these services include, among others, vegetation management, engineering, work management and safety services. General wage and benefit costs for FESC employees have also increased since the last rate case consistent with competitive market rates and rise in healthcare costs. Higher spend on public safety programs, software fees associated with critical systems, and corporate insurance coverage are also contributing to the rise in costs indirectly billed by FESC.

Q. Did any accounting methods or policy changes identified through the FERC audit impact the FESC test year amounts?

A. Yes. The FERC Division of Audits and Accounting ("DAA") within the Office of Enforcement of the FERC completed an audit of FirstEnergy for the period January 2015 to September 2021. DAA found that, according to their audit report, FirstEnergy's utilities capitalized Administrative and General ("A&G") overhead costs to Account 107, Construction Work in Process ("CWIP"), using a capitalization method that was not definitely related to construction activities based on timecard reports or a representative time study. To remedy this finding, DAA recommended that

FirstEnergy retain an independent, third-party entity to conduct a representative labor time study for the allocation of A&G overhead costs incurred to CWIP. As a result of the labor time study, which was completed during 2022, FirstEnergy adjusted its capitalization rate for its A&G overhead costs. While the change in capitalization rate had no impact on the amount of FESC indirect costs allocated to JCP&L, it did result in higher indirect costs recorded to O&M than capital in the test year.

Q. When did JCP&L make the change to its A&G capitalization methodology?

A. The independent, third-party entity completed the time study for FirstEnergy during 2022, and the revised capitalization methodology for A&G was applied effective January 1, 2022. The capitalization rate resulting from the new methodology was approximately 28% in 2022 as compared to approximately 57% in the last base rate case.

Q. Did the adjustment of the A&G capitalization rate have any impact on historical costs?

A. The FERC audit report recommended that FirstEnergy estimate the costs that would have been allocated to CWIP from the audit period, 2015 through 2021, using the newly calculated rates resulting from the time study, and remove those costs from CWIP for FERC reporting purposes. The results of the time study indicated that over the period, on average, FESC employee activities would support a capitalization rate of approximately 26% as compared to a historical rate of approximately 57%. FirstEnergy calculated the difference between historical capitalized overhead costs and those calculated as a result of the time study, including adjusting for a corresponding impact to accumulated depreciation and Allowance for Funds Used During Construction, to determine the estimated net book

value of the adjustment. As a result of this analysis, JCP&L reclassified approximately $55 million of costs from distribution capital accounts to a regulatory asset as of December 31, 2022 for FERC reporting purposes. Of the costs being moved into the regulatory asset, those on JCP&L's books prior to the end of the test year from JCP&L's last rate case (June 30, 2020) would have already been subject to a prudency review by the Board. Discussions with FERC audit staff remain ongoing, and as such, these estimates are subject to change.

IV. CONTROLS

Q. Are the Company's books and records audited by an independent accounting firm?

A. Yes. PricewaterhouseCoopers, LLP ("PwC") audited the Company's 2021 financial statements and JCP&L's FERC Form No. 1, as to which PwC concluded that FirstEnergy's and JCP&L's financial statements present fairly, in all material respects, the financial position in conformity with GAAP and in accordance with accounting requirements of the FERC's USofA, respectively. PwC also audited FirstEnergy's and JCP&L's financial statements for 2022.

Q. Please address the controls that are in place with respect to charges and expenses that FESC either directly charges or indirectly charges to JCP&L.

A. The FirstEnergy General Accounting function within the FirstEnergy Controller's department, which reports to me, is responsible for maintaining the cost allocation methodologies, which includes, among other things:

1. Annually reviewing cost allocation methodologies utilized with each service provided to determine if the most appropriate allocation methodology is being utilized and that the appropriate associate companies are being billed for services performed. This includes

reviewing the application of the factors within the SAP ERP System. New allocation methods, if any, are identified, but cannot be used until approved, as necessary, by certain regulatory authorities. The results of this annual review are discussed with and reviewed by PwC and FirstEnergy's Internal Audit department as part of annual internal controls testing.

2. Testing and validating that overhead and allocation results are reasonable. During the monthly closing process, the overhead activity is reviewed to determine that the results are appropriate and complete.
3. Monitoring and maintaining existing overheads and allocations to ensure sender (source) amounts are being applied or allocated appropriately.
4. Monitoring and analyzing the application of overheads to direct costs.

In addition, JCP&L utilizes other control mechanisms that monitor the services being provided by FESC. These control mechanisms include billing and review procedures to ensure the accuracy of FESC billings and internal/external audit examinations.

Q. Please describe the billing process as a control mechanism.

A. The FESC charges to JCP&L are generated within SAP on the basis of the recorded activity to cost centers, work orders and time records. The billing process is a monthly automated settlement of these charges within SAP. As mentioned earlier, the time documents are subject to review and approval by the supervisor or manager responsible for the employees completing such time records. In addition, FESC billings to JCP&L are reviewed and compared to budget monthly by the FirstEnergy Utilities ("FEU") Business Services group. If required, detailed FESC information (i.e., time sheets, invoices) is available to the FEU Business Services group for further analyses.

Q. Please describe the billing reconciliation procedures as a control mechanism.

A. Another control that is performed monthly is the reconciliation of FESC billings to FESC expenses with regard to services rendered to the FEU group of utilities, including JCP&L. Such reconciliation ensures that all expenses have been appropriately allocated and detects any over- or under-billings for any cost center.

Q. Please describe the audit process as a control over the FESC charges to JCP&L.

A. The internal auditing department periodically reviews and audits the FESC charges to assess the design and operating effectiveness of the control environment for FESC charges that are processed through SAP. In general, the main objectives of the internal audit review are to determine whether internal controls over the billing process to the associated companies, including JCP&L, are adequate and effective, as well as to review the cost allocation methodologies in effect and the application of these methodologies. This would include a review to ensure compliance with applicable regulatory requirements, as well as with FESC policies and procedures pertaining to billing. The specific audit procedures to be utilized will typically include interviews, observations, tests, and other procedures deemed necessary to accomplish the audit objectives.

Q. Can you elaborate further regarding the use of the audit process as a control?

A. Yes. Since 2005, the internal auditing department has conducted SOx control tests annually to ensure the appropriate use of cost allocation methodologies within SAP and that the SAP system is distributing costs correctly and in accordance with the SOx controls set in place to assure compliance with regulatory requirements.

Q. Can you discuss the use of this control relative to JCP&L?

A. Yes. The Internal Auditing department completed an audit of JCP&L's internal controls related to FirstEnergy's Cost Allocation Manual ("CAM") in 2022. The audit determined the internal controls that support and govern the cost allocation process are adequately designed to provide a reasonable level of assurance regarding reliability and integrity of the allocation of the charges billed to JCP&L, in accordance with the Service Agreement and CAM requirements.

Furthermore, the Company underwent an audit by the FERC Division of Audits for the period January 1, 2015 through September 30, 2021, with a subsequent report issued in 2022, which included selective tests of the FESC cost allocation methodologies and charges billed by FESC to the FEU utilities, including JCP&L. The audit did not identify exceptions with respect to the cost allocation methodologies, but provided recommendations related to the capitalization method of FESC costs, as described above, as well as recommended FirstEnergy perform an analysis of certain non-recoverable costs to ensure appropriate accounting classification, as described further below.

Finally, in connection with the issuance of JCP&L's financial statements, audit opinions are issued annually by an independent public accounting firm for the Company's GAAP financial statements and FERC Form 1.

FirstEnergy is currently completing a comprehensive effort under which it has updated the Shared Service Agreement and the CAM to ensure they both properly reflect current business activity. JCP&L anticipates filing both with the New Jersey BPU for review and approval later in 2023.

Q. Has the Company identified any issues outside of the allocation process with respect to charges from FESC to JCP&L?

A. As a result of certain recommendations for improvement identified during the FERC audit, as well as part of a proactive corporate effort, FirstEnergy performed a review of certain non-operating or non-recoverable costs, including costs associated with advertising, sponsorships, competitive services, and lobbying, and identified certain costs that were recorded to utility operating accounts that were included in electric service rates. The review covered the period of the FERC Audit, 2015-2021, except for review of sport sponsorships, which extended back to 2013. The internal review resulted in approximately $9.3 million, including interest, collected through retail distribution service charges to be refunded to JCP&L customers. FirstEnergy retained Craig Energy & Financial Services ("CEFS") to review and confirm the results internal management had concluded, as well as investigate other areas of non-recoverable expenses. Through its review, CEFS identified an additional approximately $370,000, including interest, collected through to retail distribution service charges to be refunded to JCP&L customers. CEFS issued its final report to FirstEnergy in the first quarter of 2023.

Q. What steps has the Company taken to address the issues that led to these charges being assessed to JCP&L?

A. As noted, FirstEnergy hired CEFS to do a separate review to confirm Management's analysis of non-recoverable and non-operating expenses. In its review, CEFS stated that it "believes in all material respects, the major, potentially high-risk, assessment coverage areas were identified and evaluated for compliance with the USofA, associated ratemaking impacts, and potential refunds owed to the regulated transmission and distribution affiliates' customers." All refunds identified have been recognized on the books of JCP&L as of December 31, 2022. The recommendations identified by CEFS are currently being implemented and anticipated to be completed by the end of 2023.

Additionally, FirstEnergy has developed a new monthly report that provides additional details, including vendor names, source of the cost and FERC account charged, for items that are billed to the utility operating companies, including JCP&L, from FESC. This report has aided accounting, business services, rates, and internal auditing in their review of FESC charges billed to the operating companies, including those in these identified categories of non-recoverable or non-operating expenses, to ensure appropriate accounting and ratemaking treatment.

Throughout 2022, FESC employees were provided training around direct charging, time charging, and invoice processing to mitigate the risk of inclusion of non-recoverable or non-operating charges in customer rates.

Q. Can you please describe this referenced training in some more detail?

A. The training was facilitated by Corporate Business Services to over 4,000 FESC employees and reinforced the existing "Time Charging for Service Company Employee Activity" policy. The training covered the importance of charging time to appropriate entities, projects or initiatives as well as included an explanation of new lobbying cost centers created to track and record time spent on lobbying activities. The training also served to remind FESC employees of appropriate invoice processing procedures, including an explanation of types of costs that should be considered non-recoverable and the corresponding accounting to apply.

All employees who entered or approved invoices in SAP were also required to complete a web-based training during 2021. This training included a review of policies for both payments made under existing purchase orders as well as non-purchase order payments and expectations of preparers and reviewers to, among other things, validate the appropriate cost collectors are charged. These additional procedures have been implemented in order for FirstEnergy to ensure proper accounting and ratemaking treatment.

Q. Has the Company taken steps to address the impact of these charges on rates?

A. Yes. On April 27, 2021, JCP&L filed a supplement to its 2020 petition for review and reconciliation of its Rider NGC in which it informed the BPU that the Company had identified funds included in distribution rates which had been either "improperly classified, misallocated, or otherwise lacked proper supporting documentation." Through this filing, JCP&L requested to refund the then-identified amounts through its Rider NGC. Similarly, JCP&L proposes to refund to customers the incremental amounts that have been further identified through its review of certain non-operating or non-recoverable costs, as discussed above, through an adjustment to the Company's Rider NGC.

Q. Do you have any conclusions about the degree and extent of the controls in place?

A. In my view, as Assistant Controller, Corporate, and Controller of JCP&L, the company has ample control over the FESC costs. First, JCP&L reviews monthly the amounts FESC bills to it. Second, the cost collector system, billing review and reconciliation procedures, as well as the periodic audits performed by the internal audit function and external auditors, provide more than adequate opportunities for effective communications, decisions or other actions pertaining to quantity and coordination of service issues between JCP&L and FESC. Third, executive and director level oversight is provided by senior management and the Boards of Directors for disclosure and accountability per the Sarbanes-Oxley Act. Fourth, as set forth above, JCP&L and FirstEnergy have implemented various steps to increase the controls pertaining to the identification of non-recoverable or non-operating expenses and have proposed a reasonable approach to addressing the issues previously identified. All provide a comprehensive framework for assuring the fairness and reasonableness of the charges for the services provided to JCP&L by FESC.

V. CONCLUSION

Q. Please summarize your direct testimony in regard to pension and OPEB expenses.

A. JCP&L's proposed adjustments to test year pension and OPEB expense are appropriate to: (1) eliminate the volatility on JCP&L's rates of the mark-to-market accounting for pension and OPEB costs used for financial reporting purposes; and (2) appropriately reflect pension and OPEB costs for ratemaking purposes by amortizing net actuarial losses over future periods. In addition, JCP&L's adjustments related to capitalized pension and OPEB costs accurately reflect the timing differences between the immediate and delayed recognition methodologies in rate base. Finally, the proposed PON mechanism will benefit both customers and the Company by reducing the impact of volatility in pension and OPEB expenses.

Q. Please summarize your direct testimony in regard to FESC relationships, charges and allocations.

A. FESC provides necessary services to JCP&L pursuant to approved cost allocation methodologies and direct charges. The level of costs charged to JCP&L in the test year is appropriate and reasonable. FirstEnergy and JCP&L have extensive controls in place by which FESC charges and allocations are reviewed on an ongoing basis.

Q. Does this conclude your direct testimony?

A. Yes, it does.

JERSEY CENTRAL POWER & LIGHT COMPANY
Pension Normalization

Adjustment to Test Year pension expense to reflect actuarial gains/losses under the delayed recognition accounting methodology.

Line No.	Description	12 ME June 30 2023 Amount
1	Pension expense per books [(a)]	$ 8,805,328
2	Remove test year pension M-t-M expense for actuarial gains/losses [(a)]	$ (42,420,383)
3	Test year pension credit excluding M-t-M for actuarial gains/losses [(a)]	$ (33,615,055)
4	Add test year pension expense for actuarial gains/losses using delayed recognition accounting methodology [(a)]	$ 37,608,718
5	Total test year pension expense (Line 3 + Line 4) [(a)]	$ 3,993,663
6	Distribution allocation percentage based on 2015 distribution S&W	91.55%
7	Total requested distribution pension expense (Line 5 x Line 6)	$ 3,656,198
8	Total distribution pension expense without M-t-M adjustment (Line 1 x Line 6)	$ 8,061,278
9	Reduction in requested distribution pension expense due to M-t-M adjustment (Line 8 - Line 7)	$ 4,405,079

(a) - Represents legal entity (Distribution and Transmission) results

JERSEY CENTRAL POWER & LIGHT COMPANY
OPEB Normalization

Adjustment to Test Year OPEB expense to reflect actuarial gains/losses under the delayed recognition accounting methodology.

Line No.	Description	12 ME June 30 2023 Amount
1	OPEB credit per books [(a)]	$ (15,104,983)
2	Remove test year OPEB M-t-M credit for actuarial gains/losses [(a)]	$ 8,297,689
3	Test year OPEB credit excluding M-t-M for actuarial gains/losses [(a)]	$ (6,807,294)
4	Add test year OPEB expense for actuarial gains/losses using delayed recognition accounting methodology [(a)]	$ 1,415,824
5	Total test year OPEB credit (Line 3 + Line 4) [(a)]	$ (5,391,470)
6	Distribution allocation percentage based on 2015 distribution S&W	91.55%
7	Total requested distribution OPEB credit (Line 5 x Line 6)	$ (4,935,891)
8	Total distribution OPEB credit without M-t-M adjustment (Line 1 x Line 6)	$ (13,828,612)
9	Reduction in requested distribution OPEB credit due to M-t-M adjustment (Line 8 - Line 7)	$ (8,892,721)

(a) - Represents legal entity (Distribution and Transmission) results

Jersey Central Power & Light
Calculation of Rate Base Adjustment

Schedule TMA-3 Attachment A

	Pension	OPEB	Total
Capitalized Costs	($66,996,742)	($1,895,268)	($68,892,010)
Accumulated depreciation	17,082,573	270,873	17,353,447
Accumlated Deferred Income Taxes	14,906,703	542,110	15,448,813
Increase / (Decrease) to Rate Base	($35,007,466)	($1,082,284)	($36,089,750)
Authorized Return on Rate base	9.34%	9.34%	9.34%
Adjustment to Revenue Requirement	($3,269,697)	($101,085)	($3,370,783)

JC Pension Actuarial (Gain) / Loss

Schedule TMA-3 Attachment B

	A	B	C = A - B	D	E = C - D
	Delayed Recognition			Immediate Recognition	Capitalized Adjustment
	Total	Income Statement	Capitalized	Capitalized	Increase / (Decrease)
2011	$26,415,000	$6,976,202	$19,438,798	$41,938,787	($22,499,989)
2012	$26,646,800	$11,220,967	$15,425,833	$34,172,525	($18,746,692)
2013	$28,781,700	$10,217,503	$18,564,197	$38,571	$18,525,626
2014	$26,888,400	$10,427,322	$16,461,078	$81,652,726	($65,191,648)
2015	$35,193,800	$13,451,070	$21,742,730	$41,468,467	($19,725,737)
2016	$38,052,800	$15,160,236	$22,892,564	$3,067,499	$19,825,065
2017	$35,027,100	$14,935,555	$20,091,545	($725,088)	$20,816,633
				Total	($66,996,742)

JC Pension - Depreciation and Accumulated Deferred Income Taxes

Schedule TMA-3 Attachment C

Book Depreciation	
Deprec Rate 2010-2014	2.17%
Deprec Rate 2015 (blended)	2.00%
Deprec Rate 2016-2018	1.94%
2011-2017 Tax Rate	35.00%
2018-2023 Tax Rate	21.00%

	Capitalized Adjustment Increase / (Decrease)	Book Depreciation 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
2011	($22,499,989)	$244,125										$244,125
2012	(18,746,692)	488,250	203,402									691,651
2013	18,525,626	488,250	406,803	(201,003)								694,050
2014	(65,191,648)	488,250	406,803	(402,006)	707,329							1,200,376
2015	(19,725,737)	488,250	406,803	(402,006)	1,414,659	197,011						2,104,716
2016	19,825,065	488,250	406,803	(402,006)	1,414,659	394,022	(192,303)					2,109,424
2017	20,816,633	488,250	406,803	(402,006)	1,414,659	394,022	(384,606)	(201,921)				1,715,200
2018	-	488,250	406,803	(402,006)	1,414,659	394,022	(384,606)	(403,843)	-			1,513,278
2019	-	488,250	406,803	(402,006)	1,414,659	394,022	(384,606)	(403,843)	-	-		1,513,278
2020	-	488,250	406,803	(402,006)	1,414,659	394,022	(384,606)	(403,843)	-	-	-	1,513,278
2021	-	488,250	406,803	(402,006)	1,414,659	394,022	(384,606)	(403,843)	-	-	-	1,513,278
2022	-	488,250	406,803	(402,006)	1,414,659	394,022	(384,606)	(403,843)	-	-	-	1,513,278
6/30/23	-	244,125	203,402	(201,003)	707,329	197,011	(192,303)	(201,921)	-	-	-	756,639
											2011-2017	$8,759,543
											2018-2023	8,323,031

	Capitalized Adjustment Increase / (Decrease)	Tax Depreciation - MACRS with Bonus Depreciation 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
2011	($22,499,989)	$22,499,989										$22,499,989
2012	(18,746,692)	-	9,724,846									9,724,846
2013	18,525,626	-	676,662	(9,610,168)								(8,933,506)
2014	(65,191,648)	-	625,858	(668,682)	33,818,167							33,775,343
2015	(19,725,737)	-	578,992	(618,478)	2,353,093	10,232,726						12,546,333
2016	19,825,065	-	535,499	(572,164)	2,176,423	712,000	(10,284,252)					(7,432,494)
2017	20,816,633	-	495,381	(529,185)	2,013,444	658,544	(715,586)	(10,798,628)				(8,876,030)
2018	-	-	458,169	(489,540)	1,862,199	609,229	(661,860)	(751,376)	-			1,026,821
2019	-	-	423,863	(452,766)	1,722,689	563,466	(612,297)	(694,963)	-	-		949,992
2020	-	-	418,239	(418,864)	1,593,284	521,253	(566,303)	(642,922)	-	-	-	904,687
2021	-	-	418,145	(413,307)	1,473,983	482,097	(523,877)	(594,627)	-	-	-	842,414
2022	-	-	418,239	(413,214)	1,454,426	445,999	(484,525)	(550,080)	-	-	-	870,845
6/30/23	-	-	209,073	(206,654)	727,050	220,041	(224,123)	(254,380)	-	-	-	471,008
											2011-2017	$53,304,481
											2018-2023	5,065,767

Accumulated Deferred Income Taxes (ADIT)	A	B	C = B - A	D	E = C * D
	Depreciation				
	Book	Tax	Difference	Tax Rate	ADIT
2011-2017	$8,759,543	$53,304,481	$44,544,938	35.00%	$15,590,728
2018-2023	$8,323,031	$5,065,767	($3,257,264)	21.00%	($684,025)
Total	$17,082,573	$58,370,248	$41,287,674		$14,906,703

JC OPEB Actuarial (Gain) / Loss

Schedule TMA-3 Attachment D

	A	B	C = A - B	D	E = C - D
	Delayed Recognition			Immediate Recognition	Capitalized Adjustment
	Total	Income Statement	Capitalized	Capitalized	Increase / (Decrease)
2011	$16,130,200	$4,568,073	$11,562,127	$13,558,928	($1,996,801)
2012	$16,846,900	$7,094,230	$9,752,670	$14,304,677	($4,552,007)
2013	$17,435,900	$6,189,744	$11,246,156	($1,902,234)	$13,148,390
2014	$15,504,700	$6,012,723	$9,491,977	$13,551,904	($4,059,927)
2015	$15,607,600	$5,965,225	$9,642,375	$11,953,689	($2,311,314)
2016	$15,714,500	$6,260,657	$9,453,843	$15,026,164	($5,572,321)
2017	$16,209,200	$6,911,603	$9,297,597	$5,848,885	$3,448,712
				Total	($1,895,268)

JC OPEB - Depreciation and Accumulated Deferred Income Taxes

Schedule TMA-3 Attachment E

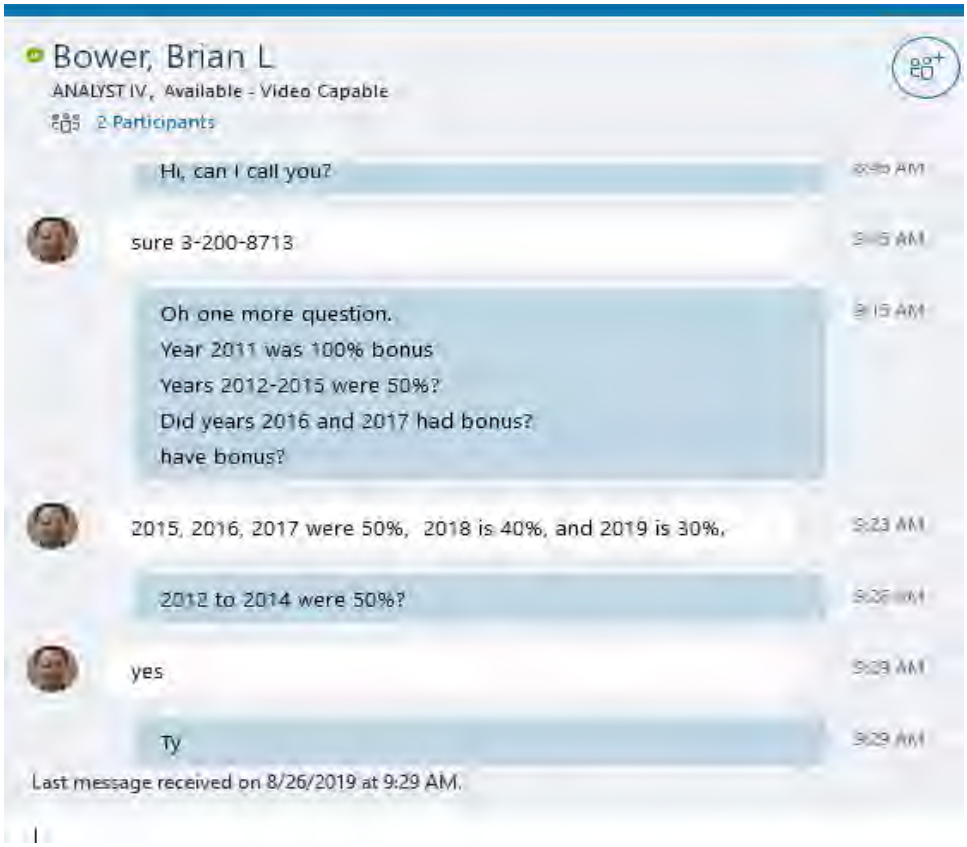
Book Depreciation	
Deprec Rate 2010-2014	2.17%
Deprec Rate 2015 (blended)	2.00%
Deprec Rate 2016-2018	1.94%
2011-2017 Tax Rate	35.00%
2018-2023 Tax Rate	21.00%

	Capitalized Adjustment Increase / (Decrease)	Book Depreciation										
		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
2011	($1,996,801)	$21,665										$21,665
2012	(4,552,007)	43,331	49,389									92,720
2013	13,148,390	43,331	98,779	(142,660)								(551)
2014	(4,059,927)	43,331	98,779	(285,320)	44,050							(99,161)
2015	(2,311,314)	43,331	98,779	(285,320)	88,100	23,084						(32,026)
2016	(5,572,321)	43,331	98,779	(285,320)	88,100	46,168	54,052					45,109
2017	3,448,712	43,331	98,779	(285,320)	88,100	46,168	108,103	(33,453)				65,709
2018	-	43,331	98,779	(285,320)	88,100	46,168	108,103	(66,905)	-			32,256
2019	-	43,331	98,779	(285,320)	88,100	46,168	108,103	(66,905)	-	-		32,256
2020	-	43,331	98,779	(285,320)	88,100	46,168	108,103	(66,905)	-	-	-	32,256
2021		43,331	98,779	(285,320)	88,100	46,168	108,103	(66,905)	-	-	-	32,256
2022		43,331	98,779	(285,320)	88,100	46,168	108,103	(66,905)	-	-	-	32,256
6/30/23		21,665	49,389	(142,660)	44,050	23,084	54,052	(33,453)	-	-	-	16,128
											2011-2017	$93,465
											2018-2023	$177,408

	Capitalized Adjustment Increase / (Decrease)	Tax Depreciation - MACRS with Bonus Depreciation										
		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total
2011	($1,996,801)	$1,996,801										$1,996,801
2012	(4,552,007)	-	2,361,354									2,361,354
2013	13,148,390	-	164,305	(6,820,727)								(6,656,422)
2014	(4,059,927)	-	151,969	(474,591)	2,106,087							1,783,465
2015	(2,311,314)	-	140,589	(438,959)	146,543	1,198,994						1,047,167
2016	(5,572,321)	-	130,028	(406,088)	135,541	83,427	2,890,642					2,833,550
2017	3,448,712	-	120,287	(375,584)	125,391	77,163	201,133	(1,789,019)				(1,640,629)
2018	-	-	111,251	(347,446)	115,972	71,385	186,032	(124,481)	-			12,713
2019	-	-	102,921	(321,347)	107,284	66,023	172,101	(115,135)	-	-		11,847
2020	-	-	101,555	(297,285)	99,225	61,076	159,173	(106,513)	-	-	-	17,231
2021			101,533	(293,341)	91,795	56,489	147,249	(98,512)	-	-	-	5,213
2022			101,555	(293,275)	90,577	52,259	136,188	(91,132)	-	-	-	(3,828)
6/30/23		-	50,767	(146,671)	45,279	25,783	62,995	(42,144)	-	-	-	(3,992)
											2011-2017	$1,725,286
											2018-2023	$39,185

Accumulated Deferred Income Taxes (ADIT)					
	A	B	C = B - A	D	E = C * D
	Depreciation				
	Book	Tax	Difference	Tax Rate	ADIT
2011-2017	$93,465	$1,725,286	$1,631,821	35.00%	$571,137
2018-2023	$177,408	$39,185	($138,223)	21.00%	($29,027)
Total	$270,873	$1,764,471	$1,493,597		$542,110

Bonus Tax Deprec (Y or N)		Y	YR 2012-2017
MACRS Tax Depr Rates		Bonus	Incl. Bonus
1	**0.03750**	**0.50000**	0.51875
2	**0.07219**		0.03610
3	**0.06677**		0.03339
4	**0.06177**		0.03089
5	**0.05713**		0.02857
6	**0.05285**		0.02643
7	**0.04888**		0.02444
8	**0.04522**		0.02261
9	**0.04462**		0.02231
10	**0.04461**		0.02231
11	**0.04462**		0.02231
12	**0.04461**		0.02231
13	**0.04462**		0.02231
14	**0.04461**		0.02231
15	**0.04462**		0.02231
16	**0.04461**		0.02231
17	**0.04462**		0.02231
18	**0.04461**		0.02231
19	**0.04462**		0.02231
20	**0.04461**		0.02231
21	**0.02231**		0.01116



JCP&L Pension & OPEB Smoothing without Purchase Accounting and without MTM

	Actuals	PENSION			OPEB		
Description	Through YTD	Total	Capital	O&M	Total	Capital	O&M
2009 Smoothing	12/31/2009	41,667,926	-	41,667,926	10,365,243	-	10,365,243
2010 Smoothing	12/31/2010	38,927,386	-	38,927,386	16,154,782	-	16,154,782
2017 Smoothing	12/31/2016	44,281,389	20,091,545	24,189,844	16,848,264	9,297,597	7,550,667
2016 Smoothing	12/31/2015	47,289,729	22,892,564	24,317,165	16,321,232	9,453,843	6,867,389
2015 Smoothing	12/31/2014	44,314,985	21,742,730	22,572,255	16,185,246	9,642,375	6,542,871
2014 Smoothing	12/31/2013	33,118,219	16,461,078	16,657,141	16,116,602	9,689,977	6,426,625
2013 Smoothing	12/31/2012	36,199,097	18,564,197	17,634,900	18,131,659	11,246,156	6,885,303
2012 Smoothing	12/31/2011	32,249,991	15,425,833	16,824,158	17,296,540	9,752,670	7,543,870
2011 Smoothing	12/31/2010	32,247,934	19,438,798	12,808,304	16,719,698	11,562,127	5,157,571

U:\Corp\Rates\MIDCIC&PC\CAPEX Rider\03-Rider RPS\1-September 2019 Filing\01-Initial Filing\03-Pension & OPEB\[Pens OPEB Smthg_JCP&L_2019-2011 WO PurchAcctg WO MTM.xls]Summary

2011 Smoothing WO Purch Acctg WO MTM

			Total	Bal Sheet	P&L
JC01	Pension	Jersey Central - Direct	26,410,000	19,438,798	6,970,202
JC01	Pension	Jersey Central - SC30, Genco allocation	5,832,104	-	5,832,104
			32,247,104	19,438,798	12,808,306
JC01	OPEB	Jersey Central - Direct	10,130,200	11,562,127	4,568,073
JC01	OPEB	Jersey Central - SC30, Genco allocation	589,498	-	589,498
			16,719,698	11,562,127	5,157,571

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2012 Smoothing WO Purch Acctg WO MTM

			Total	Bal Sheet	P&L
JC01	Pension	Jersey Central - Direct	26,646,800	15,425,833	11,220,967
JC01	Pension	Jersey Central - SC30, Genco allocation	5,673,191	-	5,673,191
			32,319,991	15,425,833	16,894,158
JC01	OPEB	Jersey Central - Direct	16,846,900	9,752,670	7,094,230
JC01	OPEB	Jersey Central - SC30, Genco allocation	449,640	-	449,640
			17,296,540	9,752,670	7,543,870

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2013 Smoothing WO Purch Acctg WO MTM

			Total	Bal Sheet	P&L
JC01	Pension	Jersey Central - Direct	28,791,700	18,564,197	10,217,503
JC01	Pension	Jersey Central - SC30, Genco allocation	7,417,397	-	7,417,397
			36,199,097	18,564,197	17,634,900
JC01	OPEB	Jersey Central - Direct	17,435,900	11,246,156	6,189,744
JC01	OPEB	Jersey Central - SC30, Genco allocation	695,559	-	695,559
			18,131,459	11,246,156	6,885,303

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2014 Smoothing WO Purch Acctg WO MTM

			Total	Bal Sheet	P&L
JC01	Pension	Jersey Central - Direct	26,888,400	16,461,078	10,427,322
JC01	Pension	Jersey Central - SC30, Genco allocation	6,229,819	-	6,229,819
			33,118,219	16,461,078	16,657,141
JC01	OPEB	Jersey Central - Direct	15,034,700	9,689,977	6,012,723
JC01	OPEB	Jersey Central - SC30, Genco allocation	611,902	-	611,902
			16,116,602	9,689,977	6,624,625

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2015 Smoothing WO Purch Acctg WO MTM

			Total	Bal Sheet	P&L
JC01	Pension	Jersey Central - Direct	35,193,800	21,742,730	13,451,070
JC01	Pension	Jersey Central - SC30, Genco allocation	9,121,185	-	9,121,185
			44,314,985	21,742,730	22,572,255
JC01	OPEB	Jersey Central - Direct	15,607,600	9,642,375	5,965,225
JC01	OPEB	Jersey Central - SC30, Genco allocation	577,646	-	577,646
			16,185,246	9,642,375	6,542,871

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2016 Smoothing WO Purch Acctg WO MTM

			Total	Bal Sheet	P&L
JC01	Pension	Jersey Central - Direct	38,052,800	22,892,564	15,160,236
JC01	Pension	Jersey Central - SC30, Genco allocation	9,156,929	-	9,156,929
			47,209,729	22,892,564	24,317,165
JC01	OPEB	Jersey Central - Direct	15,714,500	9,453,843	6,260,657
JC01	OPEB	Jersey Central - SC30, Genco allocation	606,832	-	606,832
			16,321,332	9,453,843	6,867,489

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2017 Smoothing WO Purch Acctg WO MTM

			Total	Bal Sheet	P&L
JC01	Pension	Jersey Central - Direct	35,027,100	20,091,545	14,935,555
JC01	Pension	Jersey Central - SC30, Genco allocation	9,254,289	-	9,254,289
			44,281,389	20,091,545	24,189,844
JC01	OPEB	Jersey Central - Direct	16,209,200	9,297,597	6,911,603
JC01	OPEB	Jersey Central - SC30, Genco allocation	639,064	-	639,064
			16,848,264	9,297,597	7,550,667

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2018 Smoothing WO Purch Acctg WO MTM

			Total	Bal Sheet	P&L
JC01	Pension	Jersey Central - Direct	21,314,900	-	21,314,900
JC01	Pension	Jersey Central - SC30	8,984,404	-	8,984,404
JC01	Pension	Jersey Central - Transmission	(1,371,918)	-	(1,371,918)
			28,927,386	-	28,927,386
JC01	OPEB	Jersey Central - Direct	15,655,500	-	15,655,500
JC01	OPEB	Jersey Central - SC30	589,293	-	589,293
JC01	OPEB	Jersey Central - Transmission	(89,981)	-	(89,981)
			16,154,782	-	16,154,782

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2019 Smoothing WO Purch Acctg WO MTM

			Total	Bal Sheet	P&L
JC01	Pension	Jersey Central - Direct	34,030,500	-	34,030,500
JC01	Pension	Jersey Central - SC30	9,053,214	-	9,053,214
JC01	Pension	Jersey Central - Transmission	(1,365,788)	-	(1,365,788)
			41,667,926	-	41,667,926
JC01	OPEB	Jersey Central - Direct	9,890,500	-	9,890,500
JC01	OPEB	Jersey Central - SC30	559,645	-	559,645
JC01	OPEB	Jersey Central - Transmission	(84,897)	-	(84,897)
			10,365,243	-	10,365,243

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Service Company Agreement-Utility [Execution Copy]

SERVICE AGREEMENT

This Service Agreement ("Agreement") is entered into as of the 25th day of February, 2011, by and between each of the associate companies listed on the signature page hereto (each a "Client Company"), and FirstEnergy Service Company, an Ohio corporation ("Service Company").

WHEREAS, Service Company is a direct wholly-owned subsidiary of FirstEnergy Corp., a holding company under the Public Utility Holding Company Act of 2005, as amended (the "Act");

WHEREAS, Service Company has been formed for the purpose of providing administrative, management and other services to FirstEnergy Corp. and its associate companies, including Client Company (together, the "Client Companies"); and

WHEREAS, Client Company believes that it is in its interest to enter into an arrangement whereby Client Company may agree to purchase such administrative, management and other services from Service Company as Client Company may choose at cost as determined in accordance with this Agreement and the Act;

NOW, THEREFORE, in consideration of the mutual covenants contained herein and other valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the parties hereto, intending to be legally bound, hereby agree as follows:

1. DESCRIPTION OF SERVICES.

Service Company agrees to provide certain administrative, management or other services (the "Services") to Client Company similar to those supplied to other Client Companies of Service Company. Such services are and will be provided to Client Company only at the request of Client Company. Exhibit A hereto lists and describes all of the Services that are available from Service Company.

2. PERSONNEL.

In order to provide the Services, Service Company will employ executive officers, accountants, financial advisers, technical advisers, attorneys and other persons with the necessary qualifications. If necessary, Service Company may also arrange for the services of nonaffiliated experts, consultants and attorneys in connection with the performance of any of the Services provided under this Agreement.

3. COMPENSATION AND ALLOCATION.

As and to the extent required by law, Service Company provides and will provide such services at fully allocated cost, determined in accordance with the Act. Exhibit A hereof contains rules for determining and allocating such costs.

4. TERMINATION AND MODIFICATION.

Either party to this Agreement may terminate this Agreement by providing 60 days written notice of such termination to the other party. This Agreement is subject to termination or modification at any time to the extent its performance may conflict with the provisions of the Act or with any rule, regulation or order of the Federal Regulatory Energy Commission (the "Commission") adopted before or after the making of this Agreement. This Agreement shall be subject to the approval of any state commission or other state regulatory body whose approval is, by the laws of said state, a legal prerequisite to the execution and delivery or the performance of this Agreement.

5. SERVICE REQUESTS.

Client Company and Service Company will prepare a Service Request on or before September 30th of each year listing Services to be provided to Client Company by Service Company and any special arrangements related to the provision of such Services for the coming year, based on Services provided during the preceding year. Client Company and Service Company may supplement the Service Request during the year to reflect any additional or special Services that Client Company wishes to obtain from Service Company, and the arrangements relating thereto.

6. BILLING AND PAYMENT.

Unless otherwise set forth in a Service Request, payment for Services provided by Service Company shall be by making remittance of the amount billed or by making appropriate accounting entries on the books of Client Company and Service Company. Billing will be made on a monthly basis, with the bill to be rendered as soon as practicable after the close of the month, and remittance or accounting entries completed within 30 days of billing. Any amount remaining unpaid after 30 days following receipt of the bill shall bear interest thereon from the due date of the bill until payment at a rate equal to the prime rate on the due date.

7. NOTICE.

Where written notice is required by this Agreement, all notices, consents, certificates, or other communications hereunder shall be in writing and shall be deemed given when mailed by United States registered or certified mail, postage prepaid, return receipt requested, addressed as follows:

To Client Company: c/o President
76 South Main St.
Akron, Ohio 44308

To Service Company: c/o Vice President and Controller
76 South Main Street
Akron, Ohio 44308

8. GOVERNING LAW.

This Agreement shall be governed by and construed in accordance with the laws of the State of Ohio, without regard to its conflict of laws provisions.

9. MODIFICATION.

No amendment, change or modification to this Agreement shall be valid, unless made in writing and signed by both parties hereto.

10. ENTIRE AGREEMENT.

This Agreement, together with its exhibits, constitutes the entire understanding and agreement of the parties with respect to its subject matter, and effective upon the execution of this Agreement by the respective parties hereof, any and all prior agreements, understandings or representations with respect to this subject matter are hereby terminated and canceled in their entirety and are of no further force and effect, except to the extent transactions thereunder have taken place prior to such effective date in which case such agreements will govern the terms of such transactions.

11. WAIVER.

No waiver by either party hereto of a breach of any provision of this Agreement shall constitute a waiver of any preceding or succeeding breach of the same or any other provision hereof.

12. ASSIGNMENT.

This Agreement shall inure to the benefit and shall be binding upon the parties and their respective successors and assigns. No assignment of this Agreement or either party's rights, interests or obligations hereunder may be made without the other party's consent, which shall not be unreasonably withheld, delayed or conditioned.

13. SEVERABILITY.

If any provision or provisions of this Agreement shall be held by a court of competent jurisdiction to be invalid, illegal, or unenforceable, the validity, legality, and enforceability of the remaining provisions shall in no way be affected or impaired thereby.

IN WITNESS WHEREOF, the parties have caused this Agreement to be duly executed effective as of the 25th day of February, 2011. This Agreement supercedes any previous agreement between the Service Company and the Client Companies.

FirstEnergy Service Company

By: _____
Harvey L. Wagner
Vice President & Controller

Client Companies:

Ohio Edison Company
The Cleveland Electric Illuminating Company
The Toledo Edison Company
Pennsylvania Power Company
American Transmission Systems, Incorporated
Pennsylvania Electric Company
Waverly Electric Power & Light Company
Metropolitan Edison Company
Monongahela Power Company
The Potomac Edison Company
West Penn Power Company
PATH - Allegheny Land Acquisition Company
PATH Allegheny Maryland Transmission Company, LLC
PATH Allegheny Transmission Company, LLC
PATH Allegheny Virginia Transmission Corporation
AYE Series, Potomac-Appalachian Transmission Highline, LLC
Trans-Allegheny Interstate Line Company

By: _____
Charles E. Jones
President

Jersey Central Power & Light Company

By: _____

Donald M. Lynch
President

EXHIBIT A
DESCRIPTION OF SERVICES AND ALLOCATION METHODOLOGY

1. Description Of Services

Overview

This Exhibit provides a description of all services provided by Service Company departments and the cost allocation methodologies to be used in connection therewith. All products and services are subject to Service Level Standards as negotiated between the Service Company department and Client Company. Each Client Company is classified as either a "Utility Subsidiary" or a "Non-Utility Subsidiary".

2. Cost Allocation Methodology

Overview

The costs of services provided by Service Company will be directly assigned, distributed or allocated by activity, project, program, work order or other appropriate basis. The primary basis for charges to affiliates is the direct charge method. The methodologies listed below pertain to all other costs which are not directly assigned but which make up the fully allocated cost of providing the product or service. The costs of product and services provided by the ServeCo that cannot be charged directly to the Subsidiary receiving the product or service will be allocated among the associate companies by utilizing one of the methods described below that most accurately distributes the costs. The method of cost allocation varies based on the department rendering the service. The allocation methods used by Service Company are as follows:

a. **"Multiple Factor – All"** - For the Indirect Costs for products or services benefiting the entire FirstEnergy system, FirstEnergy and all Subsidiaries will bear a fair and equitable portion of such costs. FirstEnergy will bear 5% of these Indirect Costs. The remaining Indirect Costs will be allocated among the Utility Subsidiaries and the Non-Utility Subsidiaries benefiting from the services provided based on FirstEnergy's equity investment in the respective groups. A subsequent allocation step will then occur. Among the Utility Subsidiaries, allocations will be based upon the **"Multiple Factor - Utility"** method. Among the Non-Utility Subsidiaries, allocations will be based upon the **"Multiple Factor - Non-Utility"** method.

b. **"Multiple Factor – Utility"** - For the Indirect Costs for a product or service solely benefiting one or more of the Utility Subsidiaries, each such Utility Subsidiary so benefiting will be charged a portion of the Indirect Costs based on the sum of the weighted averages of the following factors:

1. Gross transmission and/or distribution plant
2. Operating and maintenance expense excluding purchase power and fuel costs

3. Transmission and/or distribution revenues, excluding transactions with affiliates

These three (3) factors have been determined to be the most appropriate for the Utility Subsidiaries in the FirstEnergy system. Each factor will be weighted equally so that no one facet of the electric utility operations inordinately influences the distribution of Indirect Costs.

c. "Multiple Factor - Non-Utility" - For the Indirect Costs for products or services solely benefiting the Non-Utility Subsidiaries, each Non-Utility Subsidiary so benefiting receiving the product or service will be charged a proportion of the Indirect Costs based upon the total assets of each Non-Utility Subsidiary, including the generating assets under operating leases from the Utility Subsidiaries.

d. "Multiple Factor - Utility and Non-Utility" - For the Indirect Costs for a product or service benefiting one or more of the Utility and Non-Utility Subsidiaries, each such Subsidiary so benefiting is first assigned a distribution ratio that is in proportion to the Indirect Costs based on FirstEnergy's equity investment in such Subsidiaries. Following this distribution, a subsequent allocation step will then occur. Among the Utility Subsidiaries, allocations will be based upon the **"Multiple Factor-Utility."** Among the Non-Utility Subsidiaries, allocations will be based upon **"Multiple Factor - Non-Utility"**

e. "Direct Charge Ratio" - The ratio of direct charges for a particular product or service to an individual Subsidiary as a percentage of the total direct charges for a particular product or service to all Subsidiaries benefiting from such services. Indirect Costs are then allocated to each Subsidiary based on the calculated ratios.

f. "Number of Customers Ratio" - For costs of products and services driven by the number of Utility customers, the allocation method that will be used will be the number of Utility customers for the respective Utility Subsidiary receiving the product or service divided by the total number of utility customers.

g. "Number of Shopping Customers Ratio" - A "shopping customer" is defined as a Utility customer who has selected a competitive electric generation supplier. For costs of products and services driven by the number of shopping customers, the allocation method that will be used will be the number of shopping customers for the respective Utility Subsidiary receiving the product or service divided by the total number of shopping customers.

h. **"Number of Participating Employees – General"** - For costs of products and services driven by all participating employees within the FirstEnergy system, the allocation method that will be used will be the number of participating employees for the respective Subsidiary receiving the product or service divided by the total number of participating employees.

i. **"Number of Participating Employees - Utility and Non-Utility"** - For costs of products and services driven by participating employees who work for the Utility and Non-Utility Subsidiaries, the Subsidiaries receiving the product or service are first assigned a distribution ratio that is in proportion to the Indirect Costs based on FirstEnergy's equity investment in the respective groups. Costs are further allocated by using the number of participating employees for the respective Subsidiary divided by the total number of participating FirstEnergy employees.

j. **"Gigabytes Used Ratio"** - Number of gigabytes utilized by a Subsidiary receiving the product or service divided by the total number of gigabytes used by the FirstEnergy system companies applicable to that respective product or service.

k. **"Number of Computer Workstations Ratio"** - Number of computer workstations utilized by a Subsidiary receiving the product or service divided by the total number of computer workstations in use by the FirstEnergy system companies applicable to that respective product or service.

l. **"Number of Billing Inserts Ratio"** - Number of billing inserts performed for a Subsidiary receiving the product or service divided by the total number of billing inserts performed for the FirstEnergy system companies applicable to that respective product or service.

m. **"Number of Invoices Ratio"** - Number of invoices processed for a Subsidiary receiving the product or service divided by the total number of invoices processed for the FirstEnergy system companies applicable to that respective product or service.

n. **"Number of Payments Ratio"** - Number of monthly payments processed for a Subsidiary divided by the total monthly number of payments processed for the FirstEnergy system companies applicable to that respective product or service. This will not be utilized until some historical information is available out of our new automated system.

o. **"Daily Print Volume"** - Average daily print volume performed for a Subsidiary receiving the service divided by the total average daily print volume performed for the entire FirstEnergy system.

p. **"Number of Intel Servers"** - Number of Intel servers utilized by a Subsidiary receiving the product or service divided by the total number of Intel servers utilized by the FirstEnergy system.

q. **"Application Development Ratio"** - Number of application development hours budgeted for a Subsidiary receiving the service divided by the total number of budgeted application development hours for the year.

r. **"Server Support Composite"** - The average ratio of unix gigabytes, SAP gigabytes and Intel number of servers for a Subsidiary receiving the service.

3. Descriptions of Products and Services

CALL CENTER

Product or Service	Product / Service Description	Indirect Allocation Methods
Field All Inbound Regulated Calls	Field calls related to billing, credit, new service, service order completion, outages, and other miscellaneous activities.	Multiple Factor – Utility and Non-Utility
Field All Inbound Unregulated Calls	Field calls related to billing, credit, new service, service order completion, outages, and other miscellaneous activities.	Multiple Factor – Utility and Non-Utility

CUSTOMER SERVICE

Product or Service	Product / Service Description	Indirect Allocation Methods
Supplier Services	Provide customer services support to electric generation suppliers, administer and maintain Electronic Data Interface (EDI) functions and invoice suppliers.	Number of Shopping Customers Ratio
Regulatory Interface and Process Improvement: Supplier	Liaison to ensure Customer Choice requirements and develop and execute plans to improve supplier services processes.	Number of Shopping Customers Ratio
Market Support Generation (MSG) Administration	Administer and support MSG supplier functions.	Number of Shopping Customers Ratio
Regulatory Interface and Process Improvement: Regulatory	Respond to regulatory complaints from customers and develop and execute plans to improve regulatory compliance processes.	Number of Customers Ratio
Compliance	Work with regions to communicate and ensure regulatory requirements.	Multiple Factor – Utility
Power Billing	Provide billing functions for large commercial/industrial contract customers.	Number of Customers Ratio
Revenue Reporting	Perform and manage revenue reporting functions.	Number of Customers Ratio
Billing Exception Processing	Process billing exceptions.	Number of Customers Ratio
Remittance Processing	Process customer payments and deposit funds.	Number of Payments Ratio
Human Services	Coordinate and administer the various social services programs.	Number of Customers Ratio

Arrears Management/ Outsourcing Services Incorporated (OSI) Administration	Coordinate and perform arrears, credit and bankruptcy functions. Manage outside collections agencies' performance and OSI credit activities.	Number of Customers Ratio
Revenue Protection Administration	Perform revenue reporting and compliance functions.	Number of Customers Ratio
Metrics and Budget/ Customer Satisfaction Measurement	Manage Customer Services and Call Center Departments' budgets and measure performance and customer satisfaction results.	Number of Customers Ratio
Policy/Procedures Development and Documentation	Develop, document and communicate Customer Services policies and procedures.	Number of Customers Ratio
Bill Administration/ Forms Administration	Design standardized customer bills, envelopes, and forms.	Number of Customers Ratio
Meter Reading Support	Coordinate Meter Reading schedules and routing activities.	Number of Customers Ratio
Customer Information System (CIS) Control	Operate and maintain CIS.	Number of Customers Ratio

ECONOMIC DEVELOPMENT

Product or Service	**Product / Service Description**	**Indirect Allocation Methods**
Economic Development Services	Foster economic development to encourage capital investment in FirstEnergy's service areas.	Multiple Factor – Utility

TRANSMISSION & DISTRIBUTION TECHNICAL SERVICES

Product or Service	**Product / Service Description**	**Indirect Allocation Methods**
Forestry	Provide forestry services.	Multiple Factor – Utility
Distribution Reliability and Asset Records	Services include Joint User contracts, public works coordination, reliability reporting to regions and Public Utility Commissions, mutual assistance coordination, PowerOn support, cable locate ticket screening and tariff support.	Multiple Factor – Utility

Design Standards	Services include line material and construction standards, distribution line and underground maintenance practices and support, new business process support, and service practices.	Multiple Factor – Utility
Substation Services Support	Services include Substation maintenance plan coordination, practices and support, mobile substation administration and planning, and environmental compliance support.	Multiple Factor – Utility
Equipment Repair/Testing Services	Services include the maintenance, installation, maintenance, testing and repair of utility equipment.	Multiple Factor – Utility
Fleet Services	Develop fleet strategy, and perform fleet maintenance practices and support.	Multiple Factor – Utility
Financial Services	Identify revenue enhancements and cost reductions.	Multiple Factor – Utility
Substation Design and Transmission-Line Maintenance Support	Perform substation and transmission line design and project management and transmission line and substation design and material standards, right-of-way and survey services, transmission line maintenance plan coordination, practices and support, FAA activity coordination.	Multiple Factor – Utility
Planning and Protection	Perform planning and protection support for subtransmission system and overall radial system capacity planning overview, and interconnection coordination for distributed technology applications on distribution system.	Multiple Factor – Utility
Capital Budget and Equipment Support	Capital budget development and support, and major equipment specifications and procurement/repair activities for major equipment.	Multiple Factor – Utility

WORKFORCE DEVELOPMENT

Product or Service	Product / Service Description	Indirect Allocation Methods
Transmission and Distribution Skills Training	Develop and facilitate technical and safety training for workers associated with distribution activities, including line, substation, meter, fleet, warehouse, field engineering, and dispatch. Provide support through equipment evaluation, training analyses, job assessments, and project coordination.	Number of Participating Employees – General
Customer Service Skills Training	Develop and facilitate skills training for customer service groups.	Multiple Factor – Utility
External Learning Opportunities Through the Power Systems Institute	Develop educational partnerships with colleges to offer two-year degrees in electric utility technology.	Multiple Factor – Utility

ADMINISTRATIVE SERVICES

Product or Service	Product / Service Description	Indirect Allocation Methods
Provide Administrative Support Services	Provides services in production printing, document imaging, graphic services, food services, corporate mailroom and corporate courier.	Multiple Factor – Utility and Non-Utility or Multiple Factor Utility*
Provide Records Management Services	Provides services in records storage, records retrieval, records retention, records planning and engineering records.	Multiple Factor – Utility and Non-Utility or Multiple Factor Utility*
Provide Business Services	Provides services in convenience copiers, fax machines, pagers, printers, and business information center.	Multiple Factor – Utility and Non-Utility or Multiple Factor Utility*

* For services rendered only to the utilities.

EXECUTIVE

Product or Service	Product / Service Description	Indirect Allocation Methods
Executive Management	Consultation and services in management and administration of all aspects of the business.	Multiple Factor – All

COMMUNICATIONS

Product or Service	Product / Service Description	Indirect Allocation Methods
Public Relations	Provides services in media relations, financial communications, annual reports, executive presentation, public relations counsel, corporate writing, internet support and special projects.	Multiple Factor – All
Employee Communications	Provides services with update, retirees, satellite broadcast, human resource-related communications and special projects.	Number of Participating Employees – Utility and Non-Utility
Production	Provides services related to display, photography, Corporate ID, video and employee merchandise.	Multiple Factor – All
Sponsorship	Provides services related to sports marketing, university support and special projects.	Multiple Factor – All
Non-Utility Advertising	Provides services related to broadcast/print, collateral, direct mail, internet/intranet, display/merchandise, yellow/white pages, production/agency support and special projects.	Multiple Factor – Non-Utility
Utility Advertising	Provides services related to TV, radio, print, outdoors, Internet/Intranet, special projects, production, agency support and creative media placement.	Multiple Factor – Utility
Utility Bill Inserts	Provides services developing regulated bill service to Ohio, Pennsylvania and New Jersey.	Multiple Factor – Utility
Utility : Yellow / White Pages	Provides services with regulated yellow/white pages.	Multiple Factor – Utility
Utility: Research	Provides research services.	Multiple Factor – Utility
Ohio Consumer Education	Provides services related to Ohio Consumer Education statewide and locally.	Multiple Factor – Utility
Ohio Deregulation Education	Provides service related to Deregulation Education.	Multiple Factor – Utility

CORPORATE AFFAIRS AND COMMUNITY INVOLVEMENT

Product or Service	Product / Service Description	Indirect Alloeation Methods
Corporate Affairs Activities	Provide administrative support through oversight of the business practices and planning and implementation of staff, senior management and related meetings. Serves as community liaison.	Multiple Factor – Utility
Direct Community Involvement Initiatives	Provides direction in employee volunteerism, supports viable community partnerships and educational initiatives.	Multiple Factor – Utility
Energy Efficiency Programs	Directing and coordinating Ohio Weatherization and Energy Efficiency Programs for Low Income Customers.	Multiple Factor – Utility
Community Initiatives Consulting Services	Consults to regional operations and other business units and client managers for the various community programs.	Multiple Factor – Utility
Contributions Management	Directs, coordinates, monitors, and manages contributions.	Multiple Factor – Utility

CORPORATE

Product or Service	Product / Service Description	Indirect Allocation Methods
Investor Services	Stock administration, perform recordkeeping, transfer agent, registrar, paying agent, reinvestment plan administration and other services for shareholders.	None (All Direct Charge to Holding Co.)
Board of Directors Support	Support and administration of Board of Directors meetings and director compensation.	None (All Direct Charge to Holding Co.)
Annual Meeting Coordination	Coordinate the Annual Meeting of Shareholders, including the preparation and mailing of proxy materials and annual reports and the tabulation of proxies.	None (All Direct Charge to Holding Co.).
Indenture Compliance	Administer the company's indentures	Multiple Factor – Utility

HUMAN RESOURCES

Product or Service	Product / Service Description	Indirect Allocation Methods
Manage Employee Executive Compensation and Benefits	Provide management and supervision for employee and executive compensation and benefits.	Number of Participating Employees – General
Manage Workers Compensation and Disability Management	Provide management and supervision for workers compensation and disability programs.	Number of Participating Employees – General
Provide and Coordinate Human Resources Training	Design, prepare and conduct training.	Number of Participating Employees – General
Provide Employment Services	Provide staffing, relocation and employment expertise.	Number of Participating Employees – General
Provide HRIS Services	Provide and maintain Human Resources information.	Number of Participating Employees – General
Provide Diversity Management Services	Manage Affirmative Action programs, provide EEO/AA consulting services, and respond to charges.	Number of Participating Employees – General
Manage/ Administer Medical Services and Wellness Programs	Establish compliance, develop, implement, and administer medical and wellness programs.	Number of Participating Employees – General

INDUSTRIAL RELATIONS

Product or Service	Product / Service Description	Indirect Allocation Methods
Provide Labor Contract Negotiations	Provide contract negotiation services for all labor agreements.	Number of Participating Employees – General
Provide Labor Consulting Services	Provide labor consulting services.	Number of Participating Employees – General
Manage/Administer Safety Programs	Develop, implement and administer occupational safety programs.	Number of Participating Employees – General

REAL ESTATE

Product or Service	Product / Service Description	Indirect Allocation Methods
Facilities Management	Management and maintenance of office facilities.	Multiple Factor – All or Multiple Factor Utility*
Facilities Planning and Project Management	Manage office design services, furniture, project management and other capital improvements.	Multiple Factor – All or Multiple Factor Utility*
Management of Real Estate Assets	Support internal and external inquiries regarding the acquisition, divestiture and management of real estate assets	Multiple Factor – All or Multiple Factor Utility*
Manage/Administer Security Programs	Administer physical security, special investigations, security audits, security consultation and contract guard services.	Multiple Factor – All or Multiple Factor Utility*

* For services rendered only to the utilities.

FIRSTENERGY TECHNOLOGIES

Product or Service	Product / Service Description	Indirect Allocation Methods
Strategic Technologies	Develop, support and implement EPRI programs, industry initiatives, research and development programs, collaboratives and activities with universities, labs and the Department of Energy.	Multiple Factor – Utility
New Technology Assessment	Perform assessment activities for strategic technology pilots, technology assessments, marketing tests, customer pilots and due diligence reviews.	Multiple Factor – Utility and Non-Utility
Technical Application and Product Innovation	Develop, analyze and support strategic alliances, joint ventures, strategic startups, direct investments and Portfolio initiatives.	Multiple Factor – Utility and Non-Utility
New Technology and Product Market Deployment	Develop, support and implement the following initiatives: tailored solutions with existing products, commercial packages, operational efficiencies and business area solutions.	Multiple Factor – Utility and Non-Utility
Demand Response Initiatives	Provide support for corporate demand response initiatives.	Multiple Factor – Utility and Non-Utility
Renewable Energy Program and Strategy	Provide support for various corporate and regulatory initiatives to develop and implement renewable energy programs and products.	Multiple Factor – Utility

Regulated Programs and Services	Develop, support and implement programs and strategies to meet corporate initiatives and regulatory mandates and commitments related to Comprehensive Resource Assessment(CRA), customer end-use technology, distributed generation and load management.	Multiple Factor – Utility
Project Implementation Management Services	Develop and implement end-use and distributed generation technology-based products and services.	Multiple Factor – Utility and Non-Utility

TECHNOLOGY & SUPPORT SERVICES

Product or Service	Product / Service Description	Indirect Allocation Methods
Provide Network Services	Provide Internal Network Services.	Multiple Factor – Utility and Non-Utility
Maintain wireless cell sites and fiber optics network	Maintain internal wireless cell sites and fiber optic network; provide engineering, procurement, and installation services.	Multiple Factor – Utility and Non-Utility

INFORMATION TECHNOLOGY

Product or Service	Product / Service Description	Indirect Allocation Methods
Application Development	Create new or enhance existing applications; including analysis design coding, testing, system integration, and implementation, as well as any required technical writing or project manual development.	Directly Billed
Development Supervision and Tool Support	Supervision of application development employees and the support of development software tools.	Application Development Ratio
Server Support (Unix, SAP)	Create and support the network and server infrastructure to accommodate unix and SAP client server applications.	Gigabytes Used Ratio
Client Server Storage Support	Support of storage requirements for all server applications.	Server Support Composite Ratio
Server Support (Intel)	Create and support the network and server infrastructure to accommodate windows and NT client server applications.	Number of Intel Servers Ratio
Mainframe Processing and Storage Support	Execute mainframe applications, including an appropriate portion of support, started tasks, mainframe backups and microfiche services.	Gigabytes Used Ratio

Desktop Support	Help desk email and end-user tools, remote access, repair services, and general workstation support.	Number of Computer Workstations Ratio
Network Services	Includes voice, data, EMS and radio access.	Direct Charge Ratio
Inserting Services	Provide document bursting, inserting and mailing.	Number of Billing Inserts Ratio
Printing Services	Provide mainframe and client server printing services at the data center.	Daily Print Volume Ratio
Technical Consulting	Provide consulting support to departments and end-users to enable them to leverage their IT capabilities. Provide advice and consultation regarding desktop setups and configurations.	Directly Billed
Training	Provide IT training.	Multiple Factor – Utility and Non–Utility
Business Application Support	Support business application related software licenses and / or hardware maintenance provided by an outside vendor.	Directly Billed
Data Security	Disaster recovery and data security services.	Multiple Factor – Utility and Non-Utility
Project Management Office	Oversee technology projects through benefit.	Multiple Factor – Utility and Non-Utility
Provide Telecommunication Services	Provide telecommunication services and equipment.	Direct Charge Ratio
Portal Support	Support the infrastructure to accommodate internet and intranet application access.	Multiple Factor – Utility and Non-Utility

PERFORMANCE PLANNING

Product or Service	**Product / Service Description**	**Indirect Allocation Methods**
Performance Planning Services	Develop, support and execute performance planning services.	Multiple Factor – All

SUPPLY CHAIN

Product or Service	Product / Service Description	Indirect Allocation Methods
Strategic Planning, Demand management and Procurement Projects	Provide assistance in materials and services planning (demand management) and performs special procurement projects.	Multiple Factor – Utility and Non-Utility
Goods and services procurement	Procure material, equipment and contractor services. Establish, manage and administer programs, which allow internal customers to obtain goods without having to process the need through Procurement. Develop specifications, construction standards, schedules, and bills of materials.	Multiple Factor – Utility and Non-Utility
Materials Management Support	Maintain the computerized purchasing and materials management systems, and material related modules; maintain and/or modify select management reports. Analyze Supply Chain processes and measure performance. Monitor and forecast demand to ensure a continuous supply of materials.	Multiple Factor – Utility and Non-Utility
Investment Recovery Projects	Develop and implement plans for disposition of surplus assets.	Multiple Factor – Utility and Non-Utility
Process, Refurbish and Sell Materials	Perform recovery processing, investment recovery processing, refurbishing and selling materials.	Multiple Factor – Utility and Non-Utility
Provide Warehousing Services - Non-nuclear	Receive and place material into stock, insure quality requirements are met at receipt, maintain inventory counts, and update information systems. Fill customer requests for material from stock.	Multiple Factor – Utility and Non-Utility
Provide Warehousing Services - Nuclear	Receive and place material into stock, insure quality requirements are met at receipt, maintain inventory counts, and update information systems. Fill customer requests for material from stock.	None (All direct charged)
Warehousing Space Charge	Provide warehousing space to internal customers.	Multiple Factor – Utility and Non-Utility

CONTROLLERS

Product or Service	Product / Service Description	Indirect Allocation Methods
Accounting Research	Provide accounting research and consulting to ensure compliance with existing and proposed financial reporting, and regulatory accounting requirements.	Multiple Factor - All
Accounts Payable	Nonpayroll corporate disbursement services including account distribution to the general ledger. Resolve problems associated with invoice processing and maintain the accounts payable system.	Multiple Factor - All
Billing Services	Prepare non-retail electric billings.	Multiple Factor Utility
Infrastructure and Corporate Reporting, Accounting and Budgeting	Prepare Corporate Sustaining reports, subsidiary accounting and corporate budgeting, which includes reporting and support of the ledger, property records and SAP system.	Multiple Factor - All
Due Diligence	Assist value centers to determine whether proposed business acquisitions/combinations and similar transactions are desirable from a financial perspective; extensive review/analysis following preliminary review and firm intent to proceed with transaction through commitment and closing phases.	None (All direct charged)
Value Center Accounting and Budgeting	Maintain the property accounting system and provide value center accounting such as management reporting.	Multiple Factor – Utility and Non-Utility
Property Record Maintenance	Maintain corporate continuing property records.	Multiple Factor – Utility and Non-Utility or Multiple Factor Utility*
Tax Consulting and Research	Conduct tax research and tax consulting to assure compliance with statues, while evaluating alternative tax strategies within the constraints of regulations that provide additional shareholder value to the company. In addition, provide tax-consulting advice to the value centers on tax compliance and reporting issues, which includes business "start-up" support to organizations requiring assistance.	Multiple Factor – All

* For services rendered only to the utilities.

Tax Compliance	Prepare and process all schedules and information associated with corporate and subsidiary tax returns, audits, and tax litigation, assuring compliance with tax regulations and statues.	Multiple Factor – All or Multiple Factor Utility*

* For services rendered only to the utilities.

CREDIT MANAGEMENT

Product or Service	Product / Service Description	Indirect Allocation Methods
Credit Analysis and Supporting Functions	Provide detailed written credit analysis issuing recommendations on counterparty creditworthiness and assigning credit limits.	Multiple Factor – Utility and Non-Utility
Credit Policies and Procedures	Develop and support credit policies and procedures for managing credit risk. Implement and support standardized credit approval processes.	Multiple Factor – Utility and Non-Utility
Credit Management Information System	Develop and support credit management reports and calculate credit exposure on a corporate wide basis.	Multiple Factor - All

ENTERPRISE RISK MANAGEMENT

Product or Service	Product / Service Description	Indirect Allocation Methods
General Risk Management	Develop and maintain an enterprise risk management system.	Multiple Factor - All

INSURANCE SERVICES

Product or Service	Product / Service Description	Indirect Allocation Methods
Insurance Policies	Manage and support insurance policies for all the business units .	Multiple Factor – Utility and Non-Utility
Loss Control Services	Manage and support property inspections to prevent losses.	Multiple Factor – Utility and Non-Utility
Surety Bonds	Manage and support Surety Bonds.	Multiple Factor– Utility and Non-Utility
Risk Transfer and Risk Mitigation Services	Manage and support risk transfer and risk mitigation services.	Multiple Factor – Utility and Non-Utility
Ancillary Coverages	Manage and support ancillary coverages.	None (All direct charged)

INTERNAL AUDIT

Product or Service	Product / Service Description	Indirect Allocation Methods
Audit Services	Perform the following internal audit services based on risk levels and / or requests: financial, performance analysis, safeguarding of assets, computer- related and fraud investigations.	Multiple Factor – All or Multiple Factor – Utility*

INVESTMENT MANAGEMENT

Product or Service	Product / Service Description	Indirect Allocation Methods
Qualified and Non-qualified Pension and Savings Plan	Establish and implement investment policy and asset allocation strategy and monitor investment performance.	Number of Participating Employees – Utility and Non–Utility
FirstEnergy Foundation	Establish and implement investment policy and asset allocation strategy and monitor investment performance.	Multiple Factor - All
Voluntary Employee Benefit Association (VEBA) Trust	Establish and implement investment policy and asset allocation strategy and monitor investment performance.	Number of Participating Employees – Utility and Non–Utility
Nuclear Decommissioning	Establish and implement investment policy and asset allocation strategy and monitor investment performance.	None (All direct charged)
Non-Utility Generator Trust	Establish and implement investment policy and asset allocation strategy and monitor investment performance.	Multiple Factor – Non-Utility
Spent Nuclear Fuel	Establish and implement investment policy and asset allocation strategy and monitor investment performance.	None (All direct charged)
Low-Income Housing Tax Credit Partnership	Establish and implement investment policy and asset allocation strategy and monitor investment performance.	Multiple Factor - All

INVESTOR RELATIONS

Product or Service	Product / Service Description	Indirect Allocation Methods
Investor Information	Compile and communicate information to investors.	Multiple Factor – Utility* or Direct Charge to Holding Co.
Investor Education	Target and educate potential investors to promote FirstEnergy's valuation characteristics and business strategy.	None (All Direct Charge to Holding Co.)

* For services rendered only to the utilities.

Regulations Compliance	Ensure compliance with SEC Fair Disclosure regulations.	Multiple Factor - All

FirstEnergy Management Education	Provide education to management of business concerns and valuation issues of analyst/investors	Multiple Factor – All
FirstEnergy Employee Education	Actively promote understanding of financial and investor relations' issues.	Multiple Factor – All

RATES AND REGULATORY AFFAIRS

Product or Service	Product / Service Description	Indirect Allocation Methods
Regulatory Activities and Consulting	Manage regulatory activities and interfaces, including tariff development and interpretation. Monitor and participate in regulatory affairs at the local, state and federal levels.	Multiple Factor – Utility
Customer Pricing and Contracting	Develop pricing programs for regulated electric service for retail and wholesale customers, including "unbundled" costs and prices for generation, transmission and distribution service and support justification to regulators. Provide support in developing pricing for special-purpose customer programs and non-regulated energy services (e.g. prepayment, economic development, interruptible load, conjunctive-billing electric service programs).	Multiple Factor – Utility
Billing Support	Provide assistance calculating customer (external and internal) invoices and operate and maintain systems to render, collect and account for these invoices.	Multiple Factor – Utility
Sales and Load Forecasting	Develop short-term and long-term sales forecast, peak load projections and customer counts	Multiple Factor – Utility and Non-Utility

TREASURY

Product or Service	Product / Service Description	Indirect Allocation Methods
Capital Structure Management and Administration	Perform all activities related to acquiring capital and establish and administer funding, legal documentation, and record-keeping activities associated with finance programs	Multiple Factor – All
Corporate Funds Management	Plan, manage, and operate the corporate "cash-flow-cycle."	Multiple Factor – All
Corporate Forecasting	Provide regulatory support, strategy support, financial modeling and forecasting, financial and economic analysis and development of annual corporate KPI target.	Multiple Factor – All

Capital Project Evaluation and Support	Provide analytical support in the areas of financing, profitability, capital structure and cash flow.	Multiple Factor – Utility and Non-Utility
Investor Relations Activities	Provide institutional and retail security holder, buy and sell-side analysts, rating agencies, and other key members of the financial community with qualitative and quantitative information.	Multiple Factor – All

BUSINESS DEVELOPMENT

Product or Service	Product / Service Description	Indirect Allocation Methods
Mergers and Acquisitions Support	Support, evaluate and assist in the management of merger, asset acquisition and asset disposition activities.	None (All direct charged)
Internal Consulting	Perform strategic analysis/business fit, and economic analysis. Provide integration and transitional management services as needed.	None (All direct charged)

GOVERNMENTAL AFFAIRS

Product or Service	Product / Service Description	Indirect Allocation Methods
Federal Governmental Affairs Support	Activities associated with developing and maintaining relationships with federal government institutions; includes lobbying, and other support activities.	None (All direct charged)
State Governmental Affairs Support	Activities associated with developing and maintaining relationships with state government institutions; includes lobbying, and other support activities.	None (All direct charged)

LEGAL

Product or Service	Product / Service Description	Indirect Allocation Methods
Provide Governmental Affairs Support	Activities associated with developing and maintaining relationships with government institutions; includes lobbying, litigation, and other support activities.	None (All direct charged)
Nuclear Legal Consultation and Case Management	Provide legal advice for federal and state nuclear matters.	None (All direct charged)
Human Resources Legal Consultation & Case Management	Provide legal advice for human resource matters (including workers compensation, union negotiations, arbitrations, class action lawsuits, etc.).	Multiple Factor – Utility and Non-Utility

Product or Service	Product / Service Description	Indirect Allocation Methods
Employee Benefits Legal Consultation & Case Management	Provide legal advice for employee benefits matters (including health and welfare benefits, tax-qualified and non-tax qualified benefit plans and programs, pension administration, etc.).	Number of Participating Employees – Utility and Non-Utility
Tax Legal Consultation & Case Management	Provide legal advice for tax matters including federal, state & local tax matters (land tax, sales & use tax, IRS, etc.).	Multiple Factor – All
Bankruptcy Legal Consultation & Case Management	Provide legal advice for bankruptcy matters.	Multiple Factor – Utility and Non-Utility
International Legal Consultation & Case Management	Provide legal advice for international matters– contract negotiations, sale/lease agreements.	None (All direct charged)
Non-Utility Legal Consultation & Case Management	Provide legal advice on federal and state matters to Non-Utility Subsidiaries.	Multiple Factor – Non-Utilities
Regulatory Legal Consultation & Case Management	Provide legal advice for federal and state regulatory matters.	Multiple Factor – Utility
Environmental Legal Consultation & Case Management	Provide legal advice for environmental matters (other than PCB – related matters) - federal (EPA) and state (EPA), regulatory/legislative compliance issues.	None (All direct charged)
PCB Environmental Legal Consultation & Case Management	Provide legal advice for PCB-related matters - federal (EPA) and state (EPA), regulatory/legislative compliance issues.	Multiple Factor – Utility
Real Estate Legal Consultation & Case Management	Provide legal advice for real estate matters.	Multiple Factor – Utility and Non-Utility
Corporate Legal Consultation & Case Management	Provide legal advice for general corporate and transactional matters (including SEC filings, Board of Directors matters, PUHCA, Financings, Securities Matters, Intellectual Property, Technology, General Counsel matters, etc.).	Multiple Factor – All
Claims Legal Consultation & Case Management	Provide legal advice for Claims matters.	Multiple Factor - All

CLAIMS

Product or Service	Product / Service Description	Indirect Allocation Methods

Process Receivable Claims	Provide management, supervision, and performance of tasks associated with the resolution and chargeback of receivable claims.	Multiple Factor - All
Provide Corporate Support	Claims support in evaluating claims, and procuring appropriate external/internal legal resources.	Multiple Factor - All

EXHIBIT JC-5

BEFORE THE
NEW JERSEY BOARD OF PUBLIC UTILITIES

In the Matter of the Verified Petition of Jersey Central Power & Light Company for Review and Approval of Increases in, and Other Adjustments to, Its Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith

Direct Testimony
of
Dennis L. Pavagadhi

RE: JCP&L Operations, O&M Expenditures, Capital Investments, Reliability and Tariff Appendix A

EXHIBIT JC-5

Table of Contents

I. INTRODUCTION AND BACKGROUND

Q. Please state your name and business address.

A. My name is Dennis L. Pavagadhi. My business address is 300 Madison Avenue, Morristown, New Jersey 07962-1911.

Q. Please identify your employer and describe your current position.

A. I am employed by Jersey Central Power & Light Company ("JCP&L" or "Company") as Director, Operations. As I will explain in additional detail below, I am one of four such directors for JCP&L. In this capacity, I report to the President of JCP&L. My responsibilities include leading the JCP&L Operations regional organization for the northern half of JCP&L's Northern New Jersey region ("Northern Region"). This includes responsibility for lines, substation, meter services, and the fleet organizations within my designated area. Each of the three other JCP&L operations directors are similarly responsible for (i) the southern half of the JCP&L Northern Region, (ii) the northern half, and (iii) southern half, of the JCP&L Central New Jersey region ("Central Region"), respectively.

Q. Please briefly describe your educational and professional background.

A. I have worked for JCP&L for approximately 28 years. Prior to 2022, beginning in October 2019, in my position as Director, Operation Services, I was responsible for the work performed by JCP&L's 14 local line shops, and two transmission line shops, inspecting, and maintaining the Company's distribution line plant, JCP&L's Regional Engineering department, which performs distribution level system planning, reliability, design and project management functions, as well as the Company's Claims department. Prior to my position (as Director, Operation Services), I was the Director, Operations Support from

2014 to October 2019. In that role, I was responsible for JCP&L's two Distribution Control Centers, Regional Work Management, and the Substation Department at JCP&L.

Prior to 2014, I was the Manager of Engineering Services beginning in 2005. In that capacity, I was responsible for the distribution and sub-transmission planning, protection, new business, and reliability engineering groups for Morristown. In addition, I also managed the asset records, mapping, joint use, rights-of-way, and project management groups within the engineering department. Prior to 2005, I held various engineering, operations and managerial positions at the Company.

Prior to joining JCP&L, I served as an engineer for Decision System Technologies at Picatinny Arsenal and John Brown Engineering & Construction. At Decision System Technologies, I designed defense systems. At John Brown Engineering & Construction, I designed various electrical and mechanical systems.

I am a licensed Registered Professional Engineer in New Jersey and Pennsylvania, and a Certified Energy Manager. I hold a Bachelor of Science degree in Engineering from the New Jersey Institute of Technology, a Master of Science degree from the New Jersey Institute of Technology, and a Master of Science degree in Management from the College of Saint Elizabeth.

Q. Have you previously testified in Board of Public Utilities ("Board" or "BPU") proceedings?

A. Yes. Most recently, in 2020, I provided testimony in JCP&L's base rate filing in BPU Docket No. ER20020146[1] (the "2020 Base Rate Filing"), which was settled prior to hearings. In 2018 and 2019, I provided testimony in the Company's Infrastructure Investment Program ("IIP") filing in BPU Docket No. EO18070728 (the "JCP&L Reliability Plus Proceeding"). In addition, I provided pre-filed testimony in *I/M/O the Verified Petition of Jersey Central Power & Light Company for Review and Approval of Increases in, and Other Adjustments to, Its Rates and Charges for Electric Services, and for Approval of Other Proposed Tariff Revisions in Connection Therewith* ("2016 Base Rate Filing") at BPU Docket No. ER16041383, which was settled prior to hearings. Earlier, I also testified in the Company's 2012 base rate filing in BPU Docket No. ER12111052 (the "2012 Base Rate Filing"). I have also testified on behalf of the Company in other proceedings, such as before Land Use and Planning Boards for zoning and variance approvals for distribution and sub-transmission projects.

Q. Are there any schedules pertinent to your testimony?

A. Yes, the following schedules are attached to, and discussed in, my testimony:

DLP-1 – Distribution Operation & Maintenance ("O&M") Expense;

DLP-1A – 2022 Inspection and Maintenance ("I&M") Program Performance Results

DLP-2 – Revised Tariff Appendix A of the JCP&L Tariff;

DLP-3 – Current Tariff Appendix A of the JCP&L Tariff;

[1] *In the Matter of the Verified Petition of Jersey Central Power & Light Company for Review and Approval of Increases in, and Other Adjustments to, Its Rates and Charges for Electric Service, and For Approval of Other Proposed Tariff Revisions in Connection Therewith* ("2020 Base Rate Filing") BPU Docket. No.: ER20020146, Decision and Order Adopting Initial Decision and Stipulation of Settlement, dated October 28, 2020

DLP-4 – Man-hour and Vehicle Rates Used to revise Tariff Appendix A;

DLP-5 – Labor Overhead Rates Used to revise Tariff Appendix A; and

DLP-6 – Comparison of Current and Revised Tariff Appendix A Tariff Changes.

Q. What is the purpose of your direct testimony.

A. The purpose of my direct testimony is to provide support for JCP&L's base rate case filing by addressing: the capital investments and the O&M expenses associated with operating, maintaining, and managing the electric distribution system, to provide safe, adequate, and proper service to the Company's customers, including a brief description of the Company's plans. In addition, my testimony supports the requested recovery of the accumulated deferred storm damage costs. I also discuss the Company's storm process used to restore electric service following storm and weather events that impact JCP&L's service territory, which, cumulatively, have given rise to increases in those significant deferred costs. I also discuss the Company's reliability performance for 2020-2022. Finally, I provide support in this testimony for the proposed changes being made to some of the charges in Appendix A of the Company's Tariff regarding unit costs for underground construction ("Tariff Appendix A").

II. EXECUTIVE SUMMARY

Q. Please describe and summarize the content of your testimony.

A. JCP&L has a very distinct service territory in terms of its size, topography, and configuration (as two non-contiguous regions), which together are unique among New Jersey's electric public utilities, and which present challenges that can and do impact JCP&L's distribution system performance, especially as the State experiences developing

weather patterns similar to those predicted to result from, or be associated with, climate change. Turning to the Company's distribution operations expenditures and understanding that the test year for this current base rate filing is July 1, 2022 through June 30, 2023 (the "Test Year"), the Company made over $663.4 million in distribution capital investments between June 30, 2020 (the end of the test year in the 2020 Base Rate Filing) and December 31, 2022. The Company estimates capital investments of approximately $130.8 million for the first six months of 2023 for an estimated total capital investment of $794.2 million for the period since the end of the 2020 Base Rate Filing test year (June 30, 2020) through June 30, 2023 (the end of the Test Year). In 2022, JCP&L's actual capital spending was $260 million. The Company estimates that its Test Year capital spending will be $269.4 million, comprised of actual capital investments for the six months ending December 31, 2022, in the amount of $138.6 million, and six months of estimated capital investments for the six months ending June 30, 2023 in the amount of $130.8 million.

During 2022, O&M expenditures were $199.3 million. For the Test Year, JCP&L anticipates it will spend $196.5 million on O&M, comprised of actual O&M expenditures during the last six months of 2022 in the amount of $105.8 million and projected expenditures in the amount of $90.7 million during the first six months of 2023. These levels of expenditures for both capital and O&M will be updated to reflect actual 2023 spending in the Test Year as the case proceeds.

These Capital and O&M expenditures reflect JCP&L's commitment to providing safe and reliable service to its customers within its large and diverse service territory. This financial commitment is implemented using a dedicated work force organized to effectively and efficiently develop, manage, and implement its capital projects program

and to carry out the Company's comprehensive I&M programs, practices, and processes, including its diligent and aggressive vegetation management programs. Moreover, JCP&L also deploys its dedicated work force, often together with human and other resources from across the large FirstEnergy Corp. ("FirstEnergy") system, as well as from other mutual assistance resources to which it has access, to implement its storm recovery and restoration process using its dynamic incident command system ("ICS") structure.

The Company's storm processes and programs comply with industry standards and the Board's regulatory requirements as found in regulations or applicable Board orders, including the most recent storm-related Board order after Tropical Storm Isaias. These regulatory requirements and Board orders continue to evolve to incorporate the lessons learned from the latest severe weather systems that have left their mark on the State of New Jersey, generally, and, for purposes of my testimony, particularly on JCP&L's service territory.

Relative to deferred storm costs, even taking into account the results of the 2020 Base Rate Filing, the Company has incurred additional significant deferred storm costs of approximately $205.2 million, of which, approximately $148.5 million was attributable to Tropical Storm Isaias, resulting in a current total balance of almost $310 million as of December 31, 2022. The amounts deferred represent prudently incurred costs to prepare for, pre-stage resources when necessary, and to carry out the storm recovery and restoration processes. JCP&L seeks to recover these increased amounts in this proceeding as proposed by Mr. Mader in his Direct Testimony at Exhibit JC-2.

Through its capital investment programs, I&M programs, storm process implementation, the recent 2019-2020 IIP, and the overall professional management of its

electric system, the Company strives to meet the Board's system performance criteria and its overall commitment to providing safe, adequate, and proper service to its customers. JCP&L focuses significant efforts on maintaining the reliability of its electric system. The Company's analysis of its statistical reliability performance results concludes that the system's reliability performance relative to both CAIDI criteria (where the minimum standards were met) and SAIFI criteria (where the minimum standards were not met by a small margin) was negatively impacted by several unique circumstances that are not anticipated to be regular occurrences or were related to some major system enhancement work that overall is expected to prove beneficial to longer-term reliability performance.

Finally, the Company's proposed changes to the Tariff Appendix A pricing in the Tariff are justified based on an updated analysis of the costs for providing the relevant materials and services to customers as set forth in Tariff Appendix A, which pricing has been impacted by increased cost of labor and materials and has not been updated since the Company's 2020 Base Rate Filing.

III. JCP&L'S ELECTRICAL DISTRIBUTION SYSTEM

Q. Please describe JCP&L's electric distribution system.

A. The Company owns, operates, and maintains over 35,000 conductor miles of primary distribution circuits, over 1,800 circuit miles (5,469 conductor miles) of sub-transmission circuits, in excess of 340,000 JCP&L-owned poles, and approximately 250,000 transformers. JCP&L also owns, operates, and maintains 339 substations, 244 sub-transmission circuits, and 1,208 primary distribution circuits. This system provides electric distribution service to approximately 1.1 million residential, commercial, and industrial

customers, representing approximately 25% of the metered electric customers in New Jersey.

From a voltage perspective, the JCP&L distribution system is mainly a radial 12.47 kV multi-grounded wye system. Circuits operating at this voltage comprise about 55% of the distribution circuits throughout JCP&L. Other primary distribution voltages include 4.16 kV wye, 4.8 kV delta, and 34.5 kV wye, which is a distribution-level configuration (as opposed to the 34.5kV delta system, which is a transmission-level configuration).

Q. What is meant by "radial"?

A. When I refer to a radial electric distribution system, I am indicating that JCP&L's electric system was originally designed as a system having a single path over which current may flow for a part or all the way from the distribution substation or substations to the primary of a distribution transformer. This is distinguished from a loop distribution system, which loops through the service area and returns to the point of origin or connects to a second source and can be combined with the installation of switches to permit the supply of power to customers from either direction and from other sources, which can serve to reduce the number of customers impacted or the duration of the outage impact. While, as I discuss further herein, JCP&L has been working to increase the number of looped circuits in its distribution system, its distribution system remains predominantly a radial configuration, as it was originally constructed, given the geographic contours, features, and regional split of its service territory, some of which I will discuss next.

Q. Are there other aspects of JCP&L's electric distribution system that are important to understand?

A. Yes. I would like to note some of the unique topographical and other features of the Company's service territory. To begin, the service territory is relatively vast and diverse in terms of customer demographics and terrain. The territory encompasses 3,300 square miles, covering approximately 43% of New Jersey's land mass, in all or parts of thirteen[2] of New Jersey's 21 counties and 236 municipalities (or about 45% of all New Jersey municipalities). The service territory is made up of two non-contiguous regions. Electrically, this unique configuration means that the two regions are managed as one electric system but, technically, must be operated separately because of the geographic non-contiguity. This imposes limits, which might not be present in a contiguous situation, on the Company's ability to engineer cross-regional circuit ties as a component of managing system reliability. In addition, the load shift from winter to summer in the Central Region, especially at its shore communities (where the population significantly expands on a seasonal basis), is addressed differently in the Company's planning criteria from the Northern Region where the seasonal load shift is less dramatic. The distance between the two regions also adds time to the process of providing inter-regional mutual assistance when such assistance is necessary.

Forestation is another important feature of the service territory. New Jersey is a heavily forested State with forests covering about 40-45% of the land mass of the State.[3]

[2] That is (in alphabetical order), Burlington, Essex, Hunterdon, Mercer, Middlesex, Monmouth, Morris, Ocean, Passaic, Somerset, Sussex, Union, and Warren Counties.

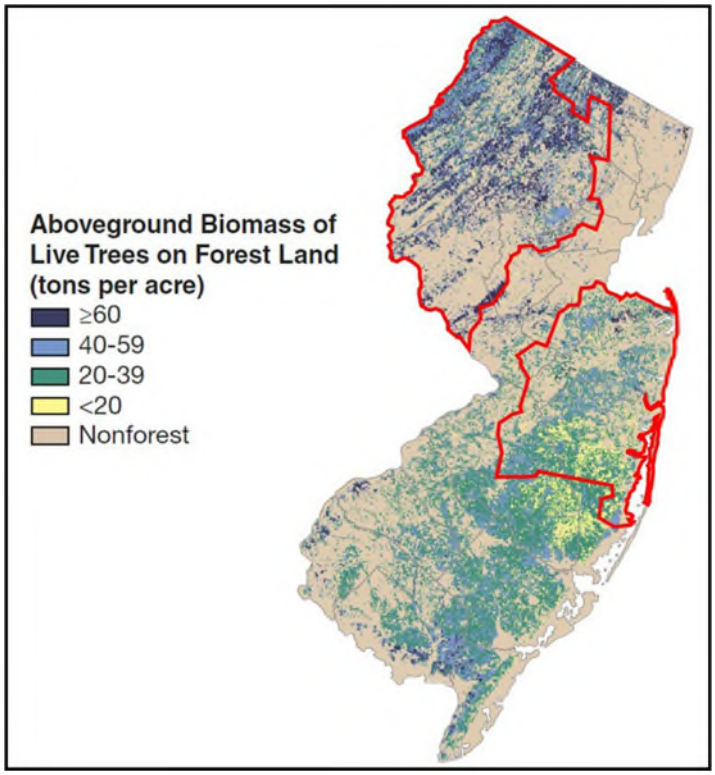
[3] Widmann, Richard H. 2005. Forests of the Garden State, Resource Bull. NE-163. Newtown Square, PA: U.S. Department of Agriculture, Forest Service, Northeastern Research Station, at p. 1. Found at: https://www.biodiversitylibrary.org/item/139135#page/3/mode/1up. **See**, also, Forests of New Jersey, 2018 found at: https://www.fs.usda.gov/nrs/pubs/ru/ru_fs218.pdf

To grasp the uniqueness of the JCP&L service territory, it helps to understand that New Jersey's "forested areas are not distributed evenly across the State. Sussex County is the most heavily forested (68 percent); Essex, Hudson, and Union Counties are the least forested. Generally, forests are concentrated in the northernmost portion of the State and in the Pine Barrens in Atlantic, Burlington, and Ocean Counties in the south. Portions of the Pine Barrens also extend into the less forested counties of Camden, Cumberland, Cape May, and Gloucester."[4]

Indeed, as earlier described, the JCP&L service territory includes two distinct regions of New Jersey: the Northern Region, which includes the heavily forested northwestern portion of New Jersey in Sussex, Hunterdon, Warren, Passaic, Morris, Somerset, Middlesex, Mercer, Essex and Union Counties; and the Central Region in the central coastal portion of the State, in Burlington, Monmouth, and Ocean Counties, which are further described in the Company's Annual System Performance Report (the "ASPR," collectively, "ASPRs") most recently filed in May of 2022. The following figure presents a graphic depiction of this data:

[4] Id. at p.4.

Figure 1[5]



Q. Are there any other features of the service territory that you would like to explain?

A. Yes. The highest elevations in the State are found in northern New Jersey and specifically coincide with the Company's Northern Region, which, in JCP&L's experience, typically experiences significantly higher snowfall (often approximately twice the amount) and incidents of freezing rain as compared to the rest of New Jersey.

[5] Crocker, Susan J., et al, New Jersey Forests 2013, U.S. Forest Service, Resource Bulletin NRS-109, January 2017 at p. 15.

Q. What is the significance of this additional information regarding the scope and scale of the JCP&L service territory and its other unique characteristics?

A. This information provides context, which I think is helpful in understanding the relationship between the variable topography of the State and the challenges these features present to the operation of the electric system within the Company's expansive and diverse service territory. In addition, this information serves as a backdrop in considering the evolving views within New Jersey on climate change vis-a-vis the Company's experience.

Q. Can you briefly elaborate?

A. Yes, I can. In this regard, it may help to refer to views expressed by Board President Fiordaliso in January 2018 when he stated:

> What climate change really means is extremes…… And we've noticed more severe storms, more variation in temperatures.[6]

I can also refer to the views of the current State administration. For instance, in June of 2019, as he announced New Jersey's return to the Regional Greenhouse Gas Initiative ("RGGI"), Governor Murphy stated that "climate change and sea level rise affect us all, and as a coastal state, New Jersey is especially vulnerable to the impacts of global warming".[7]

On October 29, 2019, the Governor also signed Executive Order No. 89 to establish a Statewide Climate Change Resilience Strategy, to include, among other things, measures

[6] Available at: https://morristowngreen.com/2018/01/14/combating-climate-change-is-a-moral-obligation-bpu-commissioner-tells-morristown-audience/

[7] Available at: https://www.nj.gov/governor/news/news/562019/approved/20190617a.shtml

to address "long-term water and energy resource security" and "increased vulnerability to extreme temperatures."[8] Among, other things, Executive Order No. 89 states:

> the scientific community has reached an overwhelming consensus that due to increasing atmospheric levels of carbon dioxide and other greenhouse gases from human activities, the Earth is warming, and temperature increases are **contributing to an increase in the frequency and intensity of *severe weather events, precipitation, and wind damage***, as well as rising sea levels; … (emphasis added)."[9]

In establishing the Climate and Flood resilience Program, the Executive Order directs the then-newly established Chief Resiliency Officer to:

> Develop a Scientific Report on Climate Change based on existing data and the best available science regarding the current and anticipated environmental effects of climate change in New Jersey, including but not limited to increased temperatures, sea level rise, increased frequency or severity of rainfall, storms and flooding, increased forest fires, and increased frequency and severity of droughts, anticipated by scientists at least through 2050; (emphasis added).[10]

More recently, in October 2020, former Commissioner McCabe of the New Jersey Department of Environmental Protection wrote (as the forward to the required Scientific Report):

> Global atmospheric warming, caused largely by human activities, is leading to significant changes in climate patterns here in New Jersey, across the United States, and around the world. Due to our geography and population, New Jersey is uniquely vulnerable to climate change and is already experiencing its impacts, including rising sea-levels, increasing temperatures, chronic flooding,

[8] Available at: https://www.nj.gov/governor/news/news/562019/approved/20191029a.shtml

[9] Id., at p.1.

[10] Id., at p.2.

> **and more frequent and intense storms**. Unfortunately, these impacts will worsen in the years ahead.[11] (Emphasis added).

Even more recently, Governor Murphy, in announcing *Executive* Order No. 307, which increases New Jersey's offshore wind goal by nearly 50 percent to 11,000 megawatts (MW) by 2040, stated:

> "Extreme weather events and severe flooding across the country leave no room for doubt – the effects of climate change are becoming more impactful and more aggressive, …"[12]

From my perspective, consideration of the data about the service territory's geographic expanse and diversity, the degree of its forestation and elevations relative to the rest of the state, and the state's increasing experience with, and concerns about, the actual or potential impacts of climate change in the form of more frequent and intense storms provide a useful and necessary backdrop against which to consider the Company's investment of capital, its O&M expenses, deferred storm costs, operations, maintenance, and performance (including storm recovery and restoration), which I will be discussing herein. These considerations have caused JCP&L and FirstEnergy to continue to look more closely at the various facts, circumstances and manifestations of weather and their impacts on service and reliability within the JCP&L service territory.

[11] 2020 New Jersey Global Warming Response Act 80x50 Report: https://www.nj.gov/dep/climatechange/docs/nj-gwra-80x50-report-2020.pdf#page=3 (A Message from The Commissioner).

[12] Governor Murphy Signs Executive Order Increasing Offshore Wind Goal to 11,000 MW by 2040, 09/21/2022. Available at: https://nj.gov/governor/news/news/562022/approved/20220921a.shtml

IV. ORGANIZATIONAL STRUCTURE AND WORKFORCE

Q. Please explain how JCP&L's electric distribution organization is structured.

A. Let me begin by providing background regarding some relatively recent organizational changes that will enhance the Company's delivery of electric service in the Test Year and beyond.

During 2020, FirstEnergy announced an initiative referred to as "FE Forward," a comprehensive project focused on improving business practices and policies along with standardizing and streamlining processes to serve customers more effectively. In January 2022, FirstEnergy completed the FE Forward operational reorganization. Under the new structure, FirstEnergy introduced a "five-state umbrella" operational management model under which its ten electric operating companies, which were previously all managed separately, would be managed going forward. Following this state umbrella model, five state operations presidents were named. As a practical matter, this change did not impact JCP&L, which is the only FirstEnergy operating company in New Jersey. In addition, FirstEnergy also named a centralized Vice President of Engineering Services, Vice President of Safety & Human Performance, Vice President of Organizational Performance Management & Strategy, and directors for these new groups under the umbrella management structure.

As part of this effort, there has also been a general reorganization of the operational approach, which is now more uniformly deployed within each state's operations.

Q. Can you explain the reorganization of the operational approach within New Jersey?

A. Yes. Generally, the operations directors in each state will report to their state president and will have regional responsibilities as well as oversight of cross-functional areas that, in general, include the lines, substations (including network, relay and controls), meter services, meter reading (where applicable) and fleet services. At JCP&L, the position of Vice President – Operations was eliminated. However, there was no other change in its executive leadership, which continues under its President, Mr. James Fakult. Now, there are four operations' directors, two in the Northern Region and two in the Central Region, each with overall operations responsibility for a distinct geographic area within their respective regions. Also, the leadership structure at JCP&L in New Jersey is now the same as in Ohio, Pennsylvania, West Virginia, and Maryland.

Q. What is the significance of this change?

A. This approach represents a change from our previous functional management structure to a regional operating structure. As a result of the reorganization, JCP&L now has four operations directors, reporting directly to the Company President, each with responsibility for lines, substation, meter services, and fleet services within their designated geographic area. This means that each operations director has responsibility for approximately one quarter of JCP&L's service territory. This structure provides direct oversight for each of the areas and provides better operations flexibility, management, and coordination for each area, which is expected to have the effect of enhancing the customer experience through more localized focus and attention by operations' management, including by the Company President, to whom the operations directors report.

Under this new operating model, FirstEnergy expects greater collaboration, engagement, and innovation across the operational organization. Through this initiative, the regional teams have and will continue to have a greater opportunity to address inefficiencies, develop solutions, enhance the customer experience, and implement tools and technologies that streamline efforts and remove barriers.

Q. How have the referenced organizational changes impacted the number of employees at JCP&L?

A. From a regional perspective, we have seen an increase of approximately 62 employees at JCP&L since 2020 (including the 50 employees discussed later in my testimony). I should also make clear that the consolidation and centralization of functions into FirstEnergy Service Company ("FESC"), which I will discuss, has not reduced jobs in New Jersey but rather has re-allocated managerial responsibility for the functions and services they perform generally without changing the reporting location of these employees in New Jersey.

Q. Given the reallocation of responsibilities as opposed to the relocation of employees, can you further explain the main features of the centralization aspect of the reorganization and its effect on the restructured operations organization?

A. Yes. Probably the most visible effect on the operations organization in New Jersey can be seen in the increased scope of operational management control within smaller geographic segments of the New Jersey service territory and a shift in the management responsibility for several support functions that remain New Jersey-based but now will be provided by FESC. Consistent with the general intent of the FE Forward initiative to create a more

sharply focused operating company platform for providing, more specifically in the case of JCP&L, safe, adequate, and proper electric service to its New Jersey customers, certain former operations-related groups that were previously locally managed within each operating company, including JCP&L, were centralized to FESC. These groups were predominantly customer-facing (as opposed to hands-on operations) personnel. In other words, while such groups may or do have interactions with customers, they are not the employee groups carrying out the day-to-day field operations associated with the actual delivery of electric service to customers. This centralization is aimed at producing an enhanced alignment of support services to deliver such services consistently, effectively, and efficiently across the FirstEnergy operating footprint. At the same time, this provides the operations organization with the opportunity to create a much sharper focus on the hands-on operations of the electric system that are the key to providing reliable electric service to customers. In this regard, facilities management has been centralized into FESC Administrative Services. Claims handling has been centralized into the corporate legal function. Human Resources has been centralized into corporate human resources. Environmental has been centralized into the FESC Utility Operations function, and the distribution control centers ("DCCs") as well as vegetation management have been centralized into the FESC Operations Support function. Finally, the former operations-based external affairs function has also been centralized into the FESC Operations' External Affairs function. Again, the aim of these initiatives is to provide additional operational and strategic flexibility, additional resources where needed, and enhanced consistency that leverages a greater sharing of best practices across the FirstEnergy system while enhancing the responsibilities and sharpening the focus of local operations on the

core functions of constructing, operating and maintaining the Company's electric system so as to maintain reliability, address existing and new customer needs for electric system capacity and service, and respond and restore service impacted by storms and other emergencies.

Q. Can you provide some additional detail about the reorganized JCP&L Operations organization from your perspective as one of its operations directors?

A. Yes. As I previously indicated, the area of geographic responsibility for each director is their complete responsibility to manage in terms of lines, substations (including network, relay, and controls), meter services, meter reading (where applicable) and fleet services. The reason I said "where applicable" with respect to meter reading is because, with the roll-out of advanced metering infrastructure ("AMI") in JCP&L's service territory, the manner of meter reading will undergo a transformation from predominantly employee-performed to automated, resulting eventually in a significant decrease in the meter reading employee complement. As this transformation and transition takes place at JCP&L, only one operations director will manage the transitioning meter reading work for all of JCP&L. In other respects, each operations director has a roughly equivalent work force comprised of 162 employees in the northern area of the Northern Region, 220 employees in the southern area of the Northern Region, 418 employees in the northern area of the Central Region,[13] and 231 employees in the southern area of the Central Region. Also, as I discuss

[13] The 418 employees include a complement of approximately 150 meter readers and associated personnel who serve throughout the JCP&L service territory and who are, and will be, subject to the transition employment impacts of AMI. In this instance, the area Operations Director is responsible for the management of this function and the transition issues associated with it. In the case of other Operations

below, populating the workforce has also included adding a total of 25 journeymen line workers during 2021 and 2022. In addition, this group of four operations directors meets regularly together, and with the JCP&L President, to promote collaboration and consistency and operational problem-solving across the JCP&L service territory.

As I alluded to earlier, this direct reporting configuration with the Company President enables more frequent and closer involvement of the Company President in the conduct of business at a localized level with the four geographically-responsible operations directors than was the case previously when the President was separated from the three operations functional directors by an operating vice president. In turn, this sharper and more concentrated localized focus is consistent with the FE Forward goal of being customer-centric and of enhancing the customer's electric service experience.

Q. Could you provide additional insight into any services enhancements through the FE Forward initiative that are now available from FESC to assist JCP&L operations?

A. Yes. The Work Management ("WM") operations organization is a good example. It was reorganized under Engineering Services to consolidate and centralize the short and long-term planning and scheduling functions for distribution line maintenance and construction under one organization to gain synergies and efficiencies. As part of this reorganization, the staffing positions for key roles in the WM Operations organization increased in New Jersey, representing an important step in the enhanced alignment of resources with business need.

Directors, they are also individually responsible for a certain important service territory-wide issue or project. For instance, in my case, I serve as the designated Incident Commander for New Jersey storm operations. Another Operations Director takes the lead on labor issues.

For example, one noteworthy work management enhancement associated with the reorganization has been the addition of readiness coordinators, whose responsibility is to ensure projects/jobs are ready for construction prior to sending a construction crew to the site. The readiness coordinators are customer-facing, trained construction employees who provide guidance and direction to customers to ensure resources, materials, permits (if necessary) and sites are ready to go when construction crews arrive. They also function to ensure the crews have the right tools, manpower, and processes in place to better serve our customers in terms of efficient and effective project work. The work of these readiness coordinators reduces non-productive time and ensures construction hours are utilized efficiently and effectively.

Q. Have these organizational changes altered or affected other operations-related services that JCP&L receives from other FESC corporate organizations, such as Operations Support?

A. No. JCP&L continues to receive support services from various departments within FESC. One significant source of this support comes from the FESC Operations Support function, which also provides similar support services for key functions used by the other FirstEnergy operating utilities.

The FESC Operations Support organization provides a wide range of technical and training support, as well as a vegetation management department to provide distribution vegetation management program oversight and transmission and distribution vegetation management expertise for this important operational support function.

JCP&L continues to be able to take advantage of FESC Operations Support's technical support and guidance where needed. This includes support services related to the execution of the Company's programs, coordination of best practices across the FirstEnergy system, and access to a large knowledge base, which assists in arriving at solutions for various system performance challenges. Through this arrangement, JCP&L continues to have at its disposal Operations Support employees readily available to provide assistance when severe weather strikes. This includes leadership and office support, as well as field support in roles such as hazard response.

Operations Support also provides administration of the outage management system, which is the system that tracks customer outages; employing a workforce development department to provide various training programs and materials to operating companies' staff; and employing the work management department that focuses on facilitating productivity enhancements through the introduction of methods and technologies, such as the now fully deployed mobile data computing terminals ("MDTs") used to enhance productivity and customer service of work crews. Further, while not directly relevant to my operations-related testimony in this distribution base rate proceeding, JCP&L receives services from the FESC transmission organization to monitor and operate the JCP&L-owned bulk transmission system, which is operationally controlled by PJM Interconnection, LLC, under the jurisdiction of the Federal Energy Regulatory Commission ("FERC").

Q. Can you describe benefits of FE Forward initiatives that have been realized to date?

A. Yes. The Company has benefited from a streamlined morning launch process, which has resulted in additional productive time for the crews. Another initiative that has already

delivered benefits is the addition of the readiness coordinators, which I mentioned above. This role was introduced as part of the FE Forward initiative. Readiness coordinators were implemented to support safety, reduce non-productive time, achieve enhancements in efficiencies and enhance the experience for affected customers. Readiness coordinators ensure jobs are ready to be worked by the crews prior to the project being placed on the schedule. This is intended to reduce or eliminate false starts; that is, a crew being dispatched to a job that is not ready to be worked. This also allows line supervisors to focus their time on supporting and supervising their crews. This further ensures construction schedules are adhered to, improving crew efficiency, and reducing costs. In a recent four-week sample of nearly 600 jobs, 176 readiness issues were identified and timely addressed resulting in an estimated labor-hour savings during this period of over 1,000 hours.

Finally, let me add that the centralized engineering function has begun implementation and use of a new automated engineering design system known as DDS (Distribution Design Studio), which will drive the process of integrating FirstEnergy construction standards into the project design process, which, in turn, is anticipated to result in increased efficiency, detail and accuracy. DDS provides a design and engineering platform that is intended to streamline electric design workflows, reduce design cycle times, and integrate design information with geographic information system ("GIS"), work management, and other systems.

Q. Have there been any technology enhancements or upgrades since 2020 that are available to JCP&L operations in New Jersey?

A. Yes. The Company has recently replaced and upgraded its outage management system ("OMS") to perform as a component of an overall Advanced Distribution Management System ("ADMS"). The former OMS, the GE Power-On system, which was originally adopted and installed in, and upgraded from time to time, since approximately 1998 was replaced at JCP&L with an Oracle Network Management System ("NMS") in late August 2022.

The Oracle NMS, once fully implemented, will have the functionality to become a full-fledged ADMS. An ADMS is a next generation software platform that supports a full suite of distribution management and optimization programs allowing for operation and control of devices from within a single software application providing dispatchers with greater control of, and better visibility to, the distribution system. ADMS will also provide future additional functionality in important areas including fault location, isolation, and service restoration ("FLISR"), volt/var reactive optimization, conservation through voltage reduction, peak demand management, and support with microgrids and electric vehicles. The implementation of the full ADMS functionality is anticipated over a time horizon of several years. Initially, however, the deployment involves only the replacement of the Power-On OMS.

As of this time, JCP&L is in the NMS post-implementation phase in which punch-list type issues are being addressed by Oracle to achieve user satisfaction through elimination of software system bugs and implementing system processing refinements. While initial employee training has been completed on a remote basis, the early post-implementation period has also identified additional training needs, particularly for field personnel, which are being addressed. JCP&L is excited to take this initial NMS

implementation step towards the eventual unleashing of the full capabilities of an ADMS, which will enhance the Company's capability to manage the electric system for the benefit of customers.

Q. Does JCP&L continue to receive support from its affiliated FirstEnergy utilities under the reorganized structure?

A. Yes. Because of the size and structure of FirstEnergy, JCP&L continues to have access to restoration personnel and other valuable resources from the nine other FirstEnergy operating utilities. This direct access to FirstEnergy workforce and equipment resources enhances JCP&L's ability to restore service to customers, particularly at times when mutual assistance resources from external entities are spread thin or are difficult to access in a short period of time. This latter assistance is typically arranged in the context of the Company's storm management process and under the leadership of an expanded Incident Command structure for a designated event, which I also discuss below.

Q. Given the significant changes in organizational structure occurring in late 2021 and in 2022, from your operational perspective at JCP&L, is there anything further that you wish to highlight regarding the JCP&L and FirstEnergy organizational structure and approach to operations in New Jersey?

A. JCP&L continues to be committed to providing safe and reliable service to its customers. The Company believes that these organizational changes offer enhancements in pursuit of this goal. The similar alignment of all the other operating employees in the several states in which FirstEnergy operates also enhances the ability of JCP&L's employees to meet this commitment within New Jersey. In this regard, the organizational structure has not

changed the fact that, just as JCP&L receives workforce and equipment support from its affiliate companies in times of storms and other emergencies, JCP&L provides similar assistance to its affiliate companies and other electric distribution companies ("EDCs") when the need arises and when JCP&L has the ability to do so (after JCP&L customers have been restored and it is reasonably determined that there is no further threat to JCP&L's territory). The realignment of certain services, as discussed herein, to or at FESC, enhances that commitment in my opinion, because it leads to a more-focused deployment of the centralized expertise, skills, and resources to local operating issues at the direction of local operations while at the same time providing advantages by way of system-wide familiarity with processes and insights and problem-solving that promote the sharing and deployment of best practices on a consistent basis.

V. ELECTRIC DISTRIBUTION CAPITAL INVESTMENTS

Q. Can you briefly describe the capital investment budgeting process?

A. JCP&L follows the rigorous standardized FirstEnergy capital investment budgeting process. After the recent FirstEnergy FE Forward reorganization, which I addressed above, one of the new direct reports to the new Director of Engineering-New Jersey, at FESC, is a FirstEnergy Manager of Distribution Portfolio for New Jersey. This change, which is applicable for each State in which FirstEnergy operates, assures greater consistency, blending an individual State focus with a more collaborative and cohesive system-wide perspective. This approach helps to assure greater consistency and enhanced alignment of FirstEnergy operating companies' capital investment budget presentations and the resulting allocations to meet their capital needs.

Capital requests by JCP&L (and the other FirstEnergy operating companies) are based on individual programs, projects, or blanket capital expenses identified by JCP&L business units and submitted in the capital allocation process. This process includes three rounds of presentation and review, with significant technical input from knowledgeable corporate and affiliated FirstEnergy utility experts regarding the most appropriate use of capital. The corporate technical review process helps to provide a common perspective across all FirstEnergy utilities. The annual capital investment prioritization process includes an initial target spending level based on historical spend. Building from that starting point, the actual budget emerges through the iterative, structured, and standardized process of three rounds of review to address, in the case of JCP&L, its targets and objectives for the coming year. The resulting target capital investment budget for JCP&L is finalized and approved by the FirstEnergy and JCP&L Boards of Directors.

Q. Can you provide additional detail about how the process works at JCP&L?

A. Yes. Each year JCP&L conducts a thorough review of all proposed capital investment projects. Potential projects are classified, prioritized, and sub-prioritized. Mandatory projects are given the highest priority, generally followed by reliability, condition, and value-added projects, in that order. Priority rankings are confirmed for each project by a cross-functional peer review team from across FirstEnergy, to ensure appropriate consistency among the FirstEnergy utilities, as indicated above. This review process ensures that: (i) the necessary engineering rigor regarding the problem-solving approach and project justification has occurred, (ii) the project scope and cost estimates have been thoroughly developed, and (iii) the anticipated project benefits are accurately represented. With the advent of the portfolio management approach briefly described above, it is

expected that the framework for considering and incorporating best practices into the capital portfolio budgeting process will assist in increasing the granularity of the process. Increasing granularity over time, together with the benefits of increased pre-engineering and benchmarking, is expected to narrow the scope and scale of blanket budgeting for some operational work categories.

Q. How much capital has JCP&L invested in its distribution system since July 1, 2020?

A. The Company has made over $663.4 million in distribution capital investments since June 30, 2020 (the end of the test year in the 2020 Base Rate Filing) and through December 31, 2022. For the first six months of 2023, JCP&L anticipates capital investments of approximately $130.8 million, for an estimated total capital investment of $794.2 million for the period since the end of the 2020 Base Filing test year (June 30, 2020) through June 30, 2023 (the end of the Test Year in this filing).

For 2022, JCP&L's actual capital spending through December 31, 2022 was $260.0 million. During the Test Year the Company currently anticipates capital expenditures of $269.4 million, comprised of six months ending December 31, 2022 of actual 2022 capital spending in the amount of $138.6 million, and six months of estimated capital expenditures in the first half of 2023 in the amount of $130.8 million. Through its capital expenditure programs, I&M programs, storm process implementation, 2019-2020 IIP, and any current or future proposed IIPs, and the overall professional management of its electric system, the Company strives to meet the Board's system performance criteria and its overall commitment to providing safe, adequate, and proper service to its customers.

Table 1 below more simply identifies the Company's total actual capital spending on its distribution system for the period July 1, 2020, through December 31, 2022, as well

as the projected spending during the first six months of 2023 and the estimated total Test Year amount, which will be updated to actuals as the case proceeds.

Table 1

Year	July 1 – Dec 31, 2020[14]	2021	January 1 - Dec 31, 2022	July 1, 2022 – Dec 31, 2022	January 1 – June 30, 2023 Forecast	Test Year Total
Capital Expenditures (millions)	$154.2	$249.2	$260.0	$138.6	$130.8	$269.4

Q. Can you briefly describe the major capital investments JCP&L has made to its system since 2020?

A. Yes. Since June 30, 2020, JCP&L has made many major capital investments to its system, including the following significant projects, the scopes of which are briefly described here: Vermont Substation Bank 1 Upgrade to 22MVA – Vermont Substation Bank 1 modular substation 14 MVA transformer ("MOD") was projected to reach its heat-run capacity in 2021. To accommodate load growth in the area served by this substation, JCP&L upgraded the Vermont Substation Bank 1 MOD with a 22 MVA Bank. The scope of work included substation engineering, site plan and environmental reports, and an upgrade of the existing Vermont Substation Bank 1 (14 MVA MOD) to a new 34.5-12.47kV 22 MVA transformer in 2021 so that future load growth can be served in this area efficiently.

[14] Please note that the Capital Expenditures for the second half of 2020 excludes IIP investments of $22 million.

Manchester Substation Capacity Project – As a result of significant load growth in Ocean County, JCP&L initiated and completed a project in 2020 to install an additional transformer and switchgear at its Manchester substation. The new transformer has a rating of 14 MVA, which was tapped directly to the 230kV transmission system, providing capacity for new load growth as well as operational flexibility, ultimately improving system reliability. This project was implemented during the second half of 2020.

JCP&L Van Hiseville Substation Bank 1 Upgrade – The Van Hiseville Substation Bank 1 (10 MVA) and Bank 2 (20 MVA) were at their heat-run capacity in 2021, when the load associated with the proposed Jackson residential commercial Town Center development came on-line. Projected peak load of 3 MVA for the residential component of the development would have overloaded existing bank capacity in this area. A new 34.5-12.47kV 20 MVA transformer was installed in 2021 so that future load growth can be served in this area efficiently.[15]

Distribution Automation Program – JCP&L has been implementing automatic load transfer schemes, or loop schemes, at many locations on its distribution system. Reclosers equipped with microprocessor-based controllers and supervisory communication and data acquisition ("SCADA") communications, which detect loss-of-supply conditions and automatically operate to allow power to be restored via an alternate circuit, have been installed. These schemes not only enhance the reliability of JCP&L's distribution system,

[15] Please note that the Company expects to replace the existing 10 MVA transformer at the Van Hiseville substation with a 20 MVA transformer utilizing existing switchgear, which has a spare breaker position for future use. This will provide additional operational flexibility in this area, in addition to the work already done (i) to serve the developing load center in this area, and (ii) to resolve distribution planning criteria bank overloads. In addition, the anticipated additional work will provide load relief to heavily loaded adjacent substations.

but they also provide real-time and historical telemetry to system operators and engineers, which assist in both day-to-day operations and longer-term planning. As of the end of 2022, JCP&L has a total of 114 automatic distribution circuit tie schemes in place, with 81 of these tie schemes also having SCADA control. Plans for installing SCADA control on the remaining 33 circuit tie schemes that do not yet have SCADA control are in progress, with a number requiring and awaiting commissioning (or re-commissioning). Such circuit tie schemes automatically transfer customers to an adjacent circuit in the event of a circuit lockout, which helps to reduce the number of customers affected from a sustained outage. Each automatic circuit tie scheme typically involves two different circuits.

Q. What are JCP&L's major categories of capital expenditures during the Test Year?

A. JCP&L's capital expenditures can mainly be broken into five major categories:

1) Reliability capital expenditures – Work identified to enhance reliability in targeted areas of the system is included under this category. The Engineering group is focused on, and dedicated to, addressing JCP&L's engineering needs, and it typically identifies this work. This consists of adding sectionalizing devices such as reclosers, fuses, TripSavers, and switches as well as addressing other miscellaneous equipment including lightning arrestors, animal guards, spacer cable insulators, or underground cable. These projects, which are generally prioritized by need and greatest benefits, improve the degree of susceptibility of the Company's electric distribution system to outages and, when an outage occurs, function to reduce the impact in terms of scope or scale, and in some cases, the duration of outages. Examples of capital reliability projects include the construction of the now in-service circuit ties for the Cozy Lake, Netcong, and Greater Crossroads Substations,

reconductoring of a significant portion of the Blair Academy, Freneau, and Fleetwood circuits, and various work to enhance the performance of less reliable circuits and equipment. This type of work continues during the Test Year. In addition to the above-described projects and types of projects, the Engineering Services group is also analyzing the replacement of, and upgrades to, substation transformers and switches at JCP&L.

2) Condition-based Expenditures – These include expenditures associated with engineering or construction field assessments, inspections and testing that indicates an increased potential for a premature or near-term equipment failure. Replacement (such as with respect to underground cable, substation breakers and poles) is then planned before the equipment becomes non-functional. Examples of capital projects in this category include the ongoing pole and underground cable replacement programs (where issues identified on a conditions-basis can be addressed), enhancements being performed at Oyster Creek substation and other substations, and remediation associated with JCP&L's I&M programs.

3) Storm-related capital repairs and forced line and substation work – This category includes installation of new plant to resolve an equipment-related issue. Plant may include items like poles, transformers, switches, and reclosers that are replaced on an emergency basis after being damaged during a storm or due to an incipient condition which requires immediate line or substation remediation at one or more of JCP&L's 339 substations. Examples of capital work in this category include the replacement of a bank breaker at the Red Bank substation, one at the Broadway substation, and one at the Columbia substation, and replacement of a Load Tap Changer ("LTC") at Traynor substation. This category also includes various switchgear and relay replacements at substations.

4) New Capacity – Distribution Planning engineers carefully analyze the distribution system to identify potential system overloads. These overloads may occur on the distribution feeder or at the distribution substation. This analysis includes identification of forecasted load growth and potential thermal overloads, and proactive action is then taken to avoid unplanned outages. Planning engineers identify least-cost solutions such as load transfers, to solve the problem. After least-cost solutions have been exhausted, additional feasible solutions are evaluated to identify a cost-effective solution. This can include circuit re-conductoring, new feeders, or new distribution substations. One of the most significant capital projects related to new capacity is the ongoing addition of a new modular substation transformer bank and switchgear at the Manchester and Van Hiseville substations to address additional capacity needs in the surrounding municipalities.

5) New business-related capital expenditures – New business expenditures include investments to connect new residential, commercial, and industrial customers to the JCP&L distribution system and include significant investments related to upgrading existing service connections for increased load. Some examples of new business capital projects include the commercial Dover Veterans Urban Renewal Housing project, which involves various underground residential development work. Additionally, the expenditure for new business residential was up approximately $4 million in 2021 as compared to 2020.

During 2022, JCP&L saw an increase in new customer connections of nearly 1,200 units, as compared to the same period in 2021. This increase is associated with the demand for housing in the JCP&L territory, which is growing at a high rate. The growth in Lakewood, New Jersey and parts of the Old Bridge district has also been very strong. In addition to the increase in the volume of this category of work, the cost of materials has

also increased since 2020 due to several factors, including supply chain issues[16] and inflation.

Given the increasingly widespread understanding that supply chain issues are having worldwide economic impacts in terms of material availability, I should add that the electric industry is not immune to these same forces. Indeed, the Company anticipates that the availability of materials due to supply chain issues will influence the deployment of capital in the Test Year and beyond. Therefore, as part of project planning, the Company is attempting to consider its experience with recent supply chain issues by making efforts to verify the availability of necessary material for proposed and/or planned capital projects that may impact the possibility of some projects coming to fruition during 2023. Notwithstanding such issues, planning is being undertaken to optimize the likelihood of completion of projects to which capital is planned to be deployed.

Q. Can you please provide an overview of JCP&L's capital spending amounts over the last five years and as projected over the next three years?

A. Yes. In this regard, I direct your attention to Table 2 below, which provides such an overview.

[16] ***See***, for example, *5 Supply Chain Challenges Impacting Utilities and How to Overcome Them*, May 19, 2022, by Emily Newton, The Network Effect, available at; https://supplychainbeyond.com/5-challenges-impacting-utility-supply-chains/ wherein are identified the following five issues: Inventory Shortfalls; Long Lead Times; Lack of Communication; Wasteful Bureaucracy; Labor Challenges.

TABLE 2

JCP&L 2018-2025 Capital	2018	2019	2020	2021	2022	2023 Budget	2024 Budget	2025 Budget
Distribution Base	$ 155,746,621	$ 176,879,760	$ 196,519,480	$ 211,539,767	$ 212,647,063	$ 182,521,538	$ 192,572,094	$ 243,621,400
Storms	$ 82,053,627	$ 45,622,222	$ 54,251,614	$ 37,611,853	$ 28,628,489	$ 24,161,436	$ 24,498,490	$ 26,316,884
Vegetation Management	$ 16,144,119	$ 16,756,480	$ 14,681,445	$ -	$ -	$ -	$ -	$ -
AMI	$ -	$ -	$ -	$ -	$ 18,388,386	$ 89,931,068	$ 144,801,832	$ 101,465,409
EV	$ -	$ -	$ -	$ -	$ 314,958	$ 5,962,713	$ 8,661,171	$ 8,703,263
IIP	$ -	$ 37,888,793	$ 60,186,234	$ -	$ -	$ -	$ -	$ -
Total Distribution Capital	**$ 253,944,367**	**$ 277,147,256**	**$ 325,638,772**	**$ 249,151,620**	**$ 259,978,896**	**$ 302,576,755**	**$ 370,533,587**	**$ 380,106,956**
Total Transmission Capita	**$ 107,219,346**	**$ 133,660,725**	**$ 165,398,414**	**$ 165,012,742**	**$ 254,456,272**	**$ 275,260,450**	**$ 331,333,624**	**$ 333,446,258**

Let me also make some observations respecting the data in the table:

- For these purposes, the terminology "distribution base capital" refers to the five categories (excluding storms, which are separately delineated in the table above) of capital spending outlined above.
- The recording of vegetation management costs as capital expenditures ended by agreement in the 2020 Base Rate Filing, effective January 1, 2021. Since then, such spending has been and continues to be captured as exclusively O&M.
- The categories of AMI and Electric Vehicle (EV) refer to programmatic spending for current or future capital spending programs that were approved and are pursuant to orders issued by the Board.
- The references to the IIP in 2019-20 refer to spending associated with the Infrastructure Investment Program previously approved by the Board that was referred to as Reliability Plus.
- While the budgeted distribution base capital for 2023 reflects an approximately $30 million decrease, the overall distribution capital spending budget for 2023 has increased by approximately $42.5 million over the prior year (2022) and represents the highest total annual distribution capital spending since 2020 (the last year for the Reliability Plus IIP).

- From a projected planning perspective, the distribution base capital spending is expected to increase by approximately $10 million in 2024 and by over $50 million in 2025 (at which point the amount is expected to exceed the 2022 distribution base capital level by approximately $31 million).
- With respect to the approximately $30 million decrease in the budgeted distribution base capital spending in 2023, such decrease needs to be seen within the overall picture in which there is increased distribution capital spending of approximately $77 million associated with programmatic spending such as for AMI and EV leading to a net increase in overall distribution capital spending of approximately $42.5 million. In addition, somewhat fewer capital-intensive, reliability-related distribution substation projects in 2023 are necessary considering the capital transmission-work described below and hereinafter. Finally, to inculcate the FE Forward philosophy and the innovation and efficiency that the associated reorganization is intended to foster, the Company's 2023 budgeting has been conceptually aggressive to emphasize and encourage the swift integration of philosophy and structure with the aim of yielding internal performative results, which, in turn, are expected to prove beneficial to the customer's experience.
- As a matter of convenience and to present a more complete operational view, the JCP&L transmission spending for the same years is also shown. In this regard, it is noted that JCP&L transmission spending increased almost $90 million from 2021 to 2022 and the 2023 budgeted JCP&L transmission spending is projected to increase by just over an additional $20 million over the 2022 level (or nearly a total increase of $110 million since 2021). As indicated later in my testimony, this transmission-related spending is also anticipated to provide reliability enhancements that will impact distribution-level customers.

- On a total transmission and distribution ("T&D") capital spending basis, it is noteworthy from the perspective of overall spending to recognize that JCP&L operations-related capital spending (excluding deferred storm expenses) has increased nearly $100 million from 2021 to 2022 and has increased by an additional approximately $63 million from 2022 to 2023. On a projected basis, further increases of approximately $124 million and an additional $12 million are expected in 2024 and 2025, respectively.

It is worth mentioning that future year projections can be re-allocated among the spending categories to, among other things, accommodate new circumstances, developments and/or contingencies, including, but not limited to, a future IIP, which, as mentioned elsewhere in my testimony, the Company is planning to file later in 2023.

Q. In addition to your observations above, can you explain other drivers of the year over year increases in capital spending since 2021?

A. In addition to the observations I have made above, let me attempt to provide some additional perspective. Clearly, the AMI and Electric Vehicle ("EV") programmatic spending impacts and drives the overall increased distribution capital spending in 2022 and going forward. Looking at the distribution base capital spending, the 2021 and 2022 actual spending increased by approximately $15 million over 2020 distribution base capital spending, which is related to the projects and categories I have discussed and described earlier. While the level of base distribution capital spending decreases somewhat in 2023 and 2024 as compared to 2021-2022, the decrease in those years is offset by the nearly $77 million increased programmatic spending for BPU authorized AMI and EV through 2025. In addition, let me reemphasize the increased transmission investment. I think this will yield distribution benefits in terms of reliability over the long term. In addition to the

somewhat aggressive philosophy and structure integration approach (described above) that is built into the 2023 budgeting view, as I alluded to earlier, the Company has announced its plans to undertake another IIP with a new filing later this year. I expect that such a filing will, undoubtedly, lead to a further refined and delineated perspective with respect to 2024-2025 distribution base spending during such proceeding.

VI. OPERATIONS AND MAINTENANCE EXPENDITURES

Q. Please describe JCP&L's O&M activities.

A. JCP&L's O&M expenses include the day-to-day activities of operating and maintaining the electric system in accordance with the Company's plans, engineering practices and regulatory requirements. This work is primarily conducted in the field by the Operations group with support from centralized services discussed previously. JCP&L develops its O&M budget based on the estimated costs of its annual I&M programs, identified O&M projects, and service restoration expenses.

Generally, the starting point for the annual O&M budget is the prior year's budget with escalation adjustments that include, but are not limited to, gross wage increases ("GWI") for bargaining and non-bargaining employees; and changes to headcount for expected staffing levels, attrition, internal transfers, and Power Systems Institute (PSI) which we have plans to transition into a traditional line and substation apprentice program in the future, and other operating personnel, including engineers.

During 2021 and 2022, JCP&L was able to recruit and hire a total of 25 experienced journeymen line workers (i.e., not graduates from the PSI program), comprised of ten in 2021 and fifteen in 2022. This was a significant step in terms of value-added experience,

in that the FirstEnergy internal PSI program requires a minimum of 5 years of training whereas an experienced journeyman lineperson has the background and experience to contribute immediately to overall operations productivity.

In addition to the journeymen linemen, the Company has recently hired 25 supervisors, several of whom were external to the Company. These outside hires bring valuable knowledge and experience from other electric distribution companies, which the Company believes will also provide value and enrich our already strong operational culture. In addition, during the reorganization, operations staffing filled 12 vacant positions. The impact of these new hires is to fully staff the new operations organizational structure that I described earlier above.

Finally, JCP&L also considers any new or changing technical or operational requirements or practices, including but not limited to the costs associated with complying with Board Orders or new regulations. This includes the Board's nine storm-related recommendations in 2020 associated with Tropical Storm Isaias,[17] in addition to the over 100 general or specific recommendations from the 2013 Hurricane Irene and Sandy Board Orders, as well as the Board's Order following the Bow Echo storm in 2015 and the Riley/Quinn Orders in 2018.

Q. Please provide an overview of the O&M budgeting process.

A. Similar to the capital allocation process, the O&M expenses are prioritized so that funds are directed to projects and activities with the greatest benefits consistent with regulatory

[17] See, *IMO The Utilities' Response to Tropical Storm Isaias*, Order Accepting Staff's Report Requiring Utilities to Implement Recommendations (BPU Docket No. EO20090607) dated November 18, 2020.

requirements. Year-over-year variations in O&M work plans must be clearly identified and reviewed during the budget review process. Planning for the upcoming budget year begins at the start of the calendar year and continues through June. The budget is generally finalized in the September–October timeframe. In addition to the specific items noted above (*i.e.*, increased headcount and GWI), the Company has also experienced increases in materials costs, which, in turn, has contributed to increased costs of materials and services the Company relies on to perform its day-to-day operations, which is reflected in the Test Year and in the 2023 budget. As will be discussed further below, the Company's vegetation management spending has also increased above agreed-upon baseline levels as part of an increasingly pro-active approach to this perennial challenge.

Q. Can you elaborate on the Company's I&M programs?

A. Yes. These programs are intended to address equipment and physical systems preventative and corrective maintenance in accordance with manufacturers', industry, and regulatory standards, as applicable, with the objective of utilizing good utility practices in keeping equipment and physical systems in good operating order. The largest single I&M program expenditure is the Company's vegetation management, or tree trimming, program. This field work is performed in compliance with BPU regulations requiring that all circuits be inspected and, if necessary, trees and other vegetation trimmed at least once every four years. I will discuss this in more detail later herein. Many utilities and states, including New Jersey, have adopted a four-year trimming periodicity, which strikes a balance between cost and reliability benefit. The work is performed primarily by outside contractors with oversight and review by Company vegetation management personnel.

Also included in the Company's I&M programs are the annual I&M of distribution line capacitors and distribution line reclosers. Overhead lines and equipment are visually inspected on a five-year cycle and an infrared inspection is performed on a four-year cycle. JCP&L also performs an underground safety and security assessment on its underground equipment on a five-year cycle. JCP&L currently employs a ten-year inspection program for all wood poles.

The I&M program for equipment inside the Company's substations, where a large number of customers could be impacted by a failure, is designed and executed to reduce unplanned equipment outages and includes general substation inspections as well as equipment-specific I&M. Visual inspections of all substations are conducted on a monthly basis and are an important part of JCP&L's asset life-cycle management approach.

The protective relay program consists of periodic testing, with prescribed periodicities or number of operations, depending on the type of relay scheme and voltage level.

The substation transformer I&M program, which includes visual inspections, utilizes a periodic diagnostic approach to evaluate the condition of each of the Company's substation power transformers. The tests conducted include dissolved gas analysis, Doble power factor testing, dielectric and physical oil testing, and transformer turns ratio, at prescribed periodicities. The infrared testing (or thermography) program is also an integral part of JCP&L's substation maintenance program. This testing is performed on an annual basis at all JCP&L substations.

The Company's battery maintenance program utilizes a monthly inspection of all substation batteries which supply DC control power to substation electrical equipment. The

batteries are cleaned as required. Impedance tests are also performed on the batteries on an annual basis.

The circuit breaker program (which includes visual inspections) uses a periodic diagnostic program that utilizes various testing methods at various frequencies to determine the condition of a circuit breaker based on the circuit breaker's unique operating characteristics. The tests conducted include Doble power factor testing, oil dielectric strength, on-line timing, moisture, high potential, and contact resistance testing at prescribed periodicities.

The JCP&L underground I&M program has been created for the maintenance of underground ducted systems. The program includes oil screen tests, dielectric tests, manhole inspections, vault inspections, and oil switch inspections performed at prescribed periodicities.

Q. Is the Company up to date on the performance of its I&M programs?

A. Yes. The Company has performed all of the I&M program requirements for 2020 and 2021 as set forth in the ASPR for each respective year. Schedule DLP-1A provides the 2022 I&M data, which will be provided in final form in the 2022 ASPR, which will be submitted to the Board in May of 2023. With a single exception, all scheduled maintenance activities have been timely completed.[18]

[18] As explained in Schedule DLP-1A, there were six relay schemes in the Central Region (out of a total of 200 for the Company) scheduled for inspection but which could not be completed due to a delay in replacing other out-of-service relays. As explained in footnote No. 31, this exception did not and does not result in

Q. Please discuss JCP&L's Test Year Distribution O&M expenditures.

A. For the twelve months beginning July 1, 2022, and ending June 30, 2023, JCP&L's electric distribution O&M expenses are projected to be $196.5 million (see Schedule DLP-1, which shows the combined Company's actual O&M spending on distribution operations for the six months ending December 2022 and the projected spending during the first six months of 2023, which will be updated to actuals as this case proceeds). Of this total, the largest portion of O&M expense is attributable to the extensive I&M programs associated with JCP&L's lines and substations, as described above.

Q. Please discuss the nature of the increased O&M spending.

A. There were several main drivers of the increases, such as, 1) forestry contractor costs; 2) vegetation management spending; 3) headcount and wage increases; and 4) materials costs.

Q. Can you briefly discuss each of these drivers?

A. Yes. Let me address them as follows:

- Forestry Contractor Costs - As explained below in the Vegetation Management section of my testimony, the Company has seen substantial increases in its forestry contractor costs over the ten-year period from 2009 to 2020 and this upward trend has continued since 2020.
- Vegetation Management Spending - The extent and amount of work performed in 2021 and 2022 resulted in the Company's increased discretionary vegetation management

any violation of any applicable (NERC/RFC) deadline and will be addressed in 2023 to meet the applicable regulatory (NERC/RFC) deadline.

spending in excess of its $31 million revenue requirement from the settlement of the 2020 Base Rate Filing. In each year, such spending increases have exceeded approximately $3 million to address issues such as, for instance, the Emerald Ash Borer ("EAB").

- Headcount and wage increases - In addition to some additions to the Company's headcount (in terms of additional supervision and troubleshooter availability), in part associated with FE Forward as discussed above, the Company has seen annual non-bargaining (approximately 4%) and bargaining (approximately 3% annually, with two 3% increases to take effect during 2023) employee wage increases. Also, the increased spending includes the Company's overtime experience.

- Materials Costs – In addition to seeing capital materials costs, the Company has also seen material cost increases related to the costs of tools, equipment and supplies that are encompassed in O&M expenditures for operations.

VII. VEGETATION MANAGEMENT PROGRAMS

Q. Can you discuss JCP&L's spending for its distribution vegetation management program during the Test Year?

A. Yes. Table 3 below provides the Company's actual spending on distribution vegetation management program mileage for six months beginning July 1, 2022, and ending December 2022, and the projected spending during the first six months of 2023 ending June 30, 2023, which will be updated to actuals as this case proceeds. These amounts are broken out from the amounts set forth in Schedule DLP-1. These amounts do not include any transmission-related vegetation management spending. Please note that these amounts include, in addition to the core four-year cycle program (as described above and further

explained below), vegetation management costs for non-core cycle activities such as on- and off-ROW tree removals, necessary pruning for cycle clearance, on corridor brush cutting or removal, other unplanned trimming, as well as vegetation management work related to small storms (meaning costs associated with storms not charged to a specific storm order).

Table 3[19]

Test Year	**Vegetation Management O&M**
July to December 2022 Actual Spend	$18,621,158
January to June 2023 Projected Spend	$15,742,184
Total	**$34,363,342**

In the settlement of the 2020 Base Rate Filing, the parties agreed upon, and the Board approved, an annual revenue requirement of $31 million in O&M for vegetation management (together with a requirement to annually report on how such funds were expended). In 2021, the Company spent $34.9 million on vegetation management and $35.1 million in 2022. As shown above, for the Test Year, the Company anticipates spending to be almost $35 million. In each case this represents spending over and above the agreed upon amount included in the O&M allowance in base rates under the 2020 Base Rate Filing settlement. As shown in Table 10 below, for a variety of reasons that I will briefly mention, the Company anticipates this trend to continue and believes its annual

[19] As mentioned earlier, as a result of the settlement in the 2020 Base Rate Filing, beginning in 2021, the Company no longer accounts for any vegetation management costs as capital expenditures.

revenue requirement in base rates should be adjusted upwards to reflect the anticipated trend.

Q. Can you provide more details regarding the JCP&L distribution vegetation management program?

A. Yes. In general, the JCP&L distribution vegetation management program is a necessary maintenance program for JCP&L to meet its obligations to provide safe and reliable service to its customers. An effective vegetation management program supports the efficient and reliable operation of JCP&L's electric distribution system. Vegetation along JCP&L's electric distribution circuits is inspected on a four-year cycle and, if necessary, such vegetation is removed, pruned, or otherwise controlled.

In addition, the Company inspects and removes vegetation outside of the regular four-year cycle, including ash trees on- and off-ROW or other priority trees, as necessary or required. This cycle-based and spot-trimming approach allows JCP&L to address specific circuit and substation vegetation-related reliability issues or concerns, including for purposes of maintaining access, making repairs, restoring service, and protecting the safety of the general public, whether such circuits or concerns arise in or outside of the cycle-based periodic trimming areas in any given year. Given the high density of forested land in the JCP&L service territory as mentioned above, the need for spot trimming arises annually and, while unpredictable as to amount or location, spot trimming is planned for in terms of annual budgeting. In addition to the four-year cycle and spot trimming work, as part of the 2020 Base Rate Case Settlement, JCP&L implemented a Vegetation Management Circuit Performance Program ("VMCP"), which includes the removal of

trees outside the trimming corridor, which are referred to as off-ROW priority trees, and which I discuss later.

Q. Please describe the standards applicable to the JCP&L distribution vegetation management program.

A. JCP&L's distribution vegetation management program is subject to, and complies with, the Board's requirements as set forth in the New Jersey Administrative Code ("N.J.A.C.") at N.J.A.C. 14:5-9.1 through 5.9.12, entitled "Electric Utility Line Vegetation Management" (the "Board's VM Regulations"), as these regulations were last amended effective August 17, 2015.[20] In addition, consistent with the Board's VM Regulations at N.J.A.C. 14:5-9.5, all vegetation clearing work is performed in compliance with ANSI Z133.1 and A-300 standards, as well as all applicable OSHA requirements. Under this framework, the degree and type of vegetation clearance required for electric distribution lines to function effectively depends upon the voltage and height of the conductor; the type of tree, its growth rate and branching habit; the extent of, or potential for, vegetation to interfere with energized conductors; and the importance of the affected facilities in maintaining safe and reliable service.

[20] Please note that during 2022 these regulations were proposed for readoption largely, but not entirely, without amendment. 54 N.J.R. 1584(a) (August 15, 2022). In January 2023, the Board voted to approve the readoption and to issue notice of readoption, providing details as to the final rules, including any amendments thereto. That notice was published on February 21, 2023 in the New Jersey Register (55 N.J.R. 312(b)). The Company's preliminary review of the rulemaking as adopted continues to be that amendments to the vegetation management rules are not material in scope and do not impact anything covered in my testimony.

Q. How is the Company's vegetation management work performed and administered?

A. The FirstEnergy Forestry department for New Jersey (comprised primarily of a general manager, manager, two supervisors, and forestry specialists) utilizes qualified external contractors to perform its vegetation management. The completed trimming is inspected by the Company's forestry specialists to ensure that the contractor work is performed in compliance with FirstEnergy's Vegetation Management Specifications.

Although the number of contract employees varies during a year, at any given time there can be in excess of 450 contract and Forestry employees performing work under the JCP&L distribution vegetation management program in and throughout the service territory.

Q. Please describe the mileage dimensions of the JCP&L electric distribution system.

A. In total, the JCP&L Forestry group maintains approximately 13,900 circuit miles of distribution circuits (including the "wye-configured" 34.5 kV distribution facilities) as part of its distribution vegetation management program. On a pro-rata basis, approximately one-quarter of this distribution mileage is addressed annually under the cyclical JCP&L distribution vegetation management program. In addition, as mentioned above, some locations may require more frequent spot control to address reliability and safety concerns as needed.

Q. Are the same number of miles subjected to vegetation management every year?

A. No. The annual circuit mileage varies due to such factors as circuit configurations and the geographic and municipal aspects of the circuits designated for vegetation management in any given year. These mileage allocations are reviewed periodically to further consider

circuit and substation changes. Table 4 below illustrates the most recent information regarding the mileage to be trimmed for the JCP&L distribution lines during a specific year of a four-year cycle.

Table 4

Description	4 Year Cycle 2022/2026	4 Year Cycle 2023/2027	4 Year Cycle 2024/2028	4 Year Cycle 2025/2029	Total (circuit miles)	Average (circuit miles)
Distribution & Sub-transmission	3,449	3,424	3,373	3,607	13,853	3,463

Q. Is the Company complying with the Board's regulations in the conduct of its vegetation management program?

A. Yes. JCP&L's maintenance cycles are up-to-date and were completed annually on a timely basis for the period 2020-2022.

Q. Are there other aspects of the vegetation management program that you can describe?

A. Yes. I think it is worth mentioning that non-storm, tree-related outages that impact 500 or more customers or are greater than three hours in duration are required to be investigated by a Company forester, tracked by the Company, and reported in the Company's ASPR. The Company has fully complied with this requirement and the results of these investigations have been informative. For instance, Table 5 below, provides a summary of data from such investigations for the period 2018-2022:

Table 5

Year	Number of Investigations	On ROW	Off ROW	Secondary Service	500 or more Customers Affected	Less than 500 Customers Affected	Less than 10 Customers Affected
2018	1,789	15%	69%	16%	5%	95%	58%
2019	1,688	10%	65%	24%	6%	94%	57%
2020	1,895	13%	65%	21%	5%	95%	58%
2021	1,572	15%	64%	21%	5%	95%	62%
2022	1,956	17%	71%	12%	4%	96%	59%

This data provides a perspective, which I alluded to above and will describe more fully below, on the numbers and sources of tree-related incidents, their impact on reliability, and the Company's ability to prevent them.

Q. Would you describe the perspective this table provides regarding the sources of the outages?

A. Yes. Given the heavily forested character of the JCP&L service territory, it may not be surprising that this data continues to confirm that off-ROW trees are a primary driver of tree-related outages and their associated impact on reliability. To provide some context, nearly 84% of all tree-related outages were attributed to off-ROW trees and trees falling on secondary wires. Both off-ROW trees and secondaries are outside the scope of the Company responsibility or control relative to its vegetation management programs.

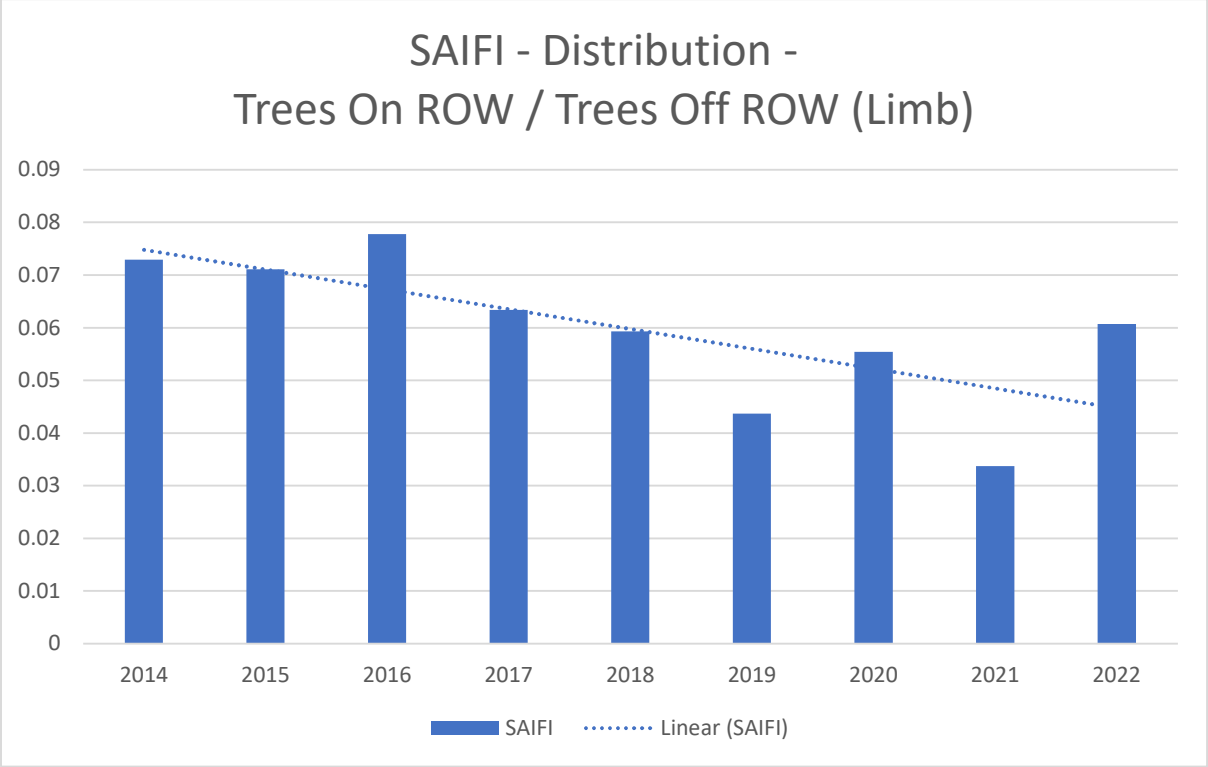
Q. Are there any other initiatives or programs that the Company has implemented beyond the four-year cycle maintenance for vegetation management?

A. Yes, in recent years, there have been three initiatives that were or are still considered outside the normal cycle maintenance: 1) Overhanging vegetation in Zone 1 (the Lock-out

zone), which is now considered part of normal maintenance; 2) Zone 2 overhang removals (221 circuits through the Reliability Plus IIP); and 3) the VMCP.

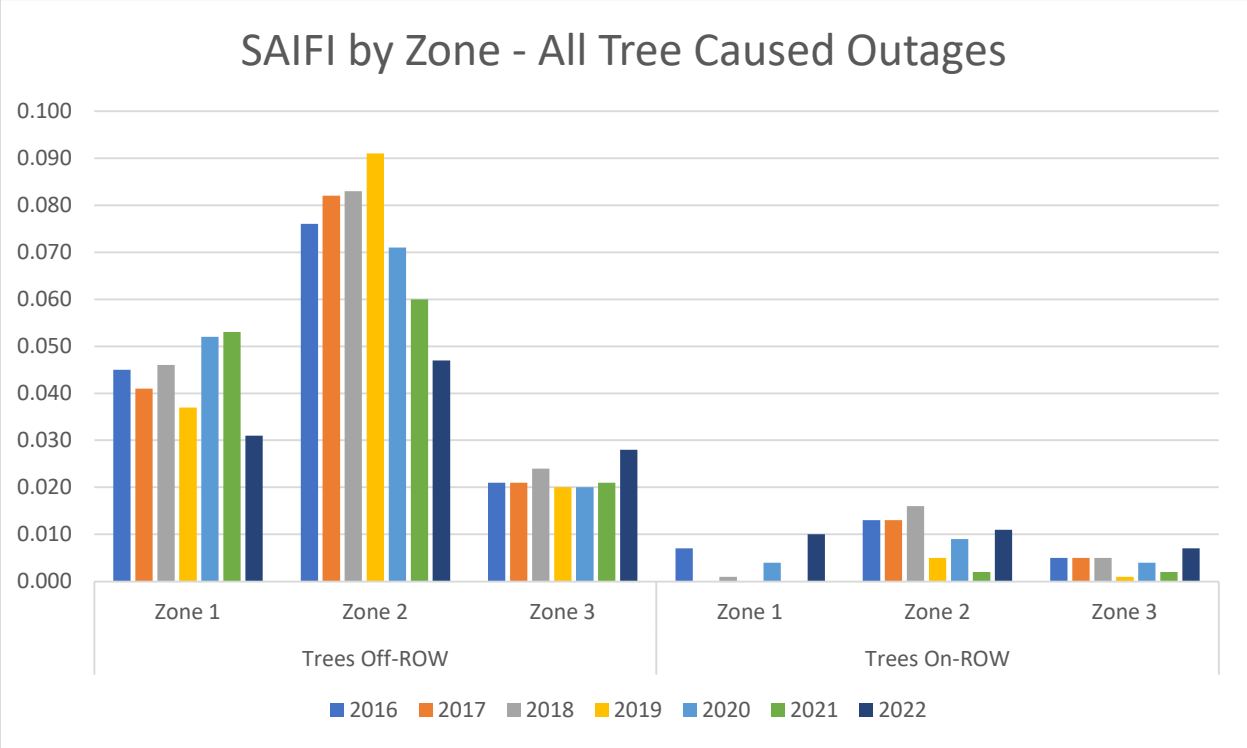
1. Overhanging vegetation in Zone 1 (the Lock-out zone): As a matter of background, it may be helpful to explain that prior to January 1, 2016, the Company had piloted internal efforts to address overhanging vegetation in Zone 1, which is known as the Lock-out zone, in addition to its normal vegetation management program. In August 2015, after stakeholder meetings, the Board adopted amended regulations pertaining, among other things, to Zone 1 overhang, which went into effect January 1, 2016. Between January 2016 and December 2019, JCP&L completed the removal of overhanging vegetation clearing on the feeder main line from the breaker up to the first protective device (Zone 1 or Lock-Out Zone). Since January 2020, JCP&L has been maintaining these clearances as part of its normal vegetation management cycle. In my experience, the number of tree-related interruptions resulting from feeder breaker lock-outs in Zone 1 represented a substantial portion of the total tree-related outages prior to completing this clearing. As a result of this initiative to remove overhang in the Lock-Out Zone (Zone 1), the frequency of outages caused by on-ROW trees and limb fall-ins from off-ROW trees (as opposed to fallen off-ROW trees themselves, as to which the Company does not have rights) have trended downward since 2016, as indicated in the table below.

Table 6



2. Zone 2 Overhang Removal: With Zone 1 in a purely maintenance mode, the Company also performed Zone 2 overhang removal as part of the JCP&L Reliability Plus IIP on 221 circuits during 2019 and 2020, which represents about 18% of JCP&L's 1,208 primary distribution circuits. The benefits of that limited Zone 2 removal effort are beginning to be realized now. As displayed in the following table, the Company has seen a marked decrease in the SAIFI impact to customers from outages caused by off-ROW tree-related outages, including those caused by overhang and fall-ins from such trees in Zone 2 from 2020 through 2022.

Table 7



3. VMCP: In addition to the foregoing, beginning in January 2021, the Company began the VMCP. The Company's VMCP Program includes enhanced on-cycle work, circuit review, assessment and planning, and off-ROW mitigation. In this program, resulting from the settlement of the 2020 Base Rate Filing, the Company tracks tree-related SAIDI by separately tracking tree-related outages on its circuits during blue-sky, minor weather days, and major events. The Company also separately tracks tree-related SAIDI for the 221 circuits (again, approximately 18% of all of JCP&L's circuits) that received Zone 2 overhang removal as part of the JCP&L Reliability Plus Program in 2019 and 2020. For circuits that are to be trimmed in a given year (*i.e.*, on-cycle), if an on-cycle circuit's tree-related SAIDI reliability performance is in the bottom 12% for any two of the last four consecutive years when compared to the four-year rolling average tree-related SAIDI

performance, the circuit will be reviewed to assess whether overhanging limbs, on-corridor trees, or off-corridor trees are the driver(s) for the circuit's tree-related SAIDI performance. The tree-related SAIDI performance of Zone 1 and Zone 2 will be analyzed to determine trees downstream of protective devices that have operated that may be trimmed or removed to address tree-related outages. The circuit will also be reviewed to determine a work plan for enhanced on-cycle work to enhance its tree-related performance. Enhanced on-cycle work will be performed on the selected circuit and the tree-related SAIDI performance will be monitored on a quarterly basis until the tree-related SAIDI performance has enhanced for two consecutive quarters. This VMCP also includes off-ROW tree mitigation as part of the enhanced on-cycle work, targeting off-ROW danger[21] trees on the selected on-cycle circuits.

In 2020, twenty-one (21) circuits were identified for the review, assessment, and enhanced on-cycle work plan. Enhanced vegetation management activities were completed (during 2021) on those twenty-one (21) circuits, including additional tree trimming or removal and herbicide applications. Additionally, all 530 of the hazard[22] trees identified on those circuits were removed. Of the 4,047 danger trees identified, 1,145 were removed from those circuits.

[21] "Danger trees" are defined as any tree on or off the right-of-way that could contact electric supply lines if it were to fall (N.J.A.C. 14:5-1.2).

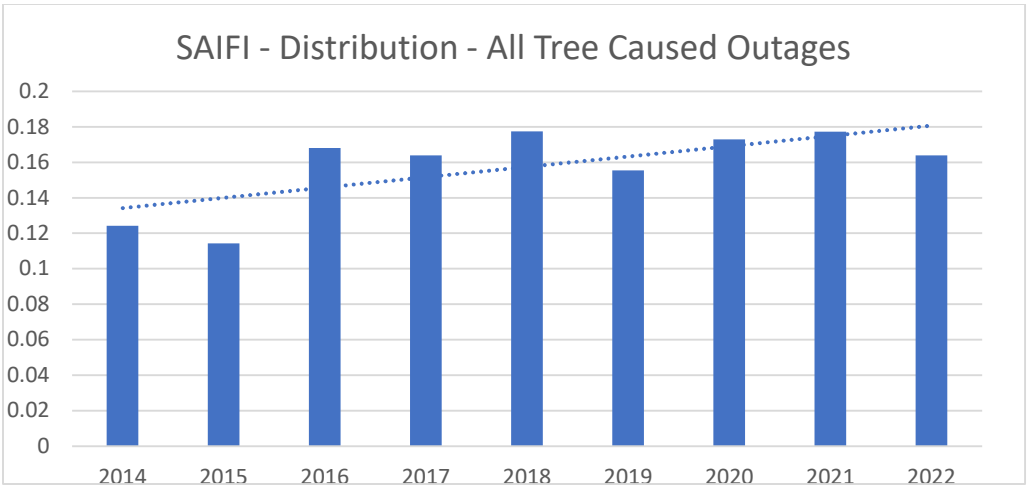
[22] "Hazard trees" are structurally unsound trees on or off rights-of-way that could strike electric supply lines when they fail. Structural unsoundness distinguishes a Hazard tree from a Danger tree, such that while all Hazard trees are Danger trees, not all Danger trees are Hazard trees (N.J.A.C. 14:5-1.2).

In early 2022, seventeen (17) circuits were identified under this program. The Company completed a review and assessment of each of the seventeen (17) circuits and all enhanced on-cycle work was completed by year-end.

Q. Have these programs enhanced the overall tree-related circuit reliability performance?

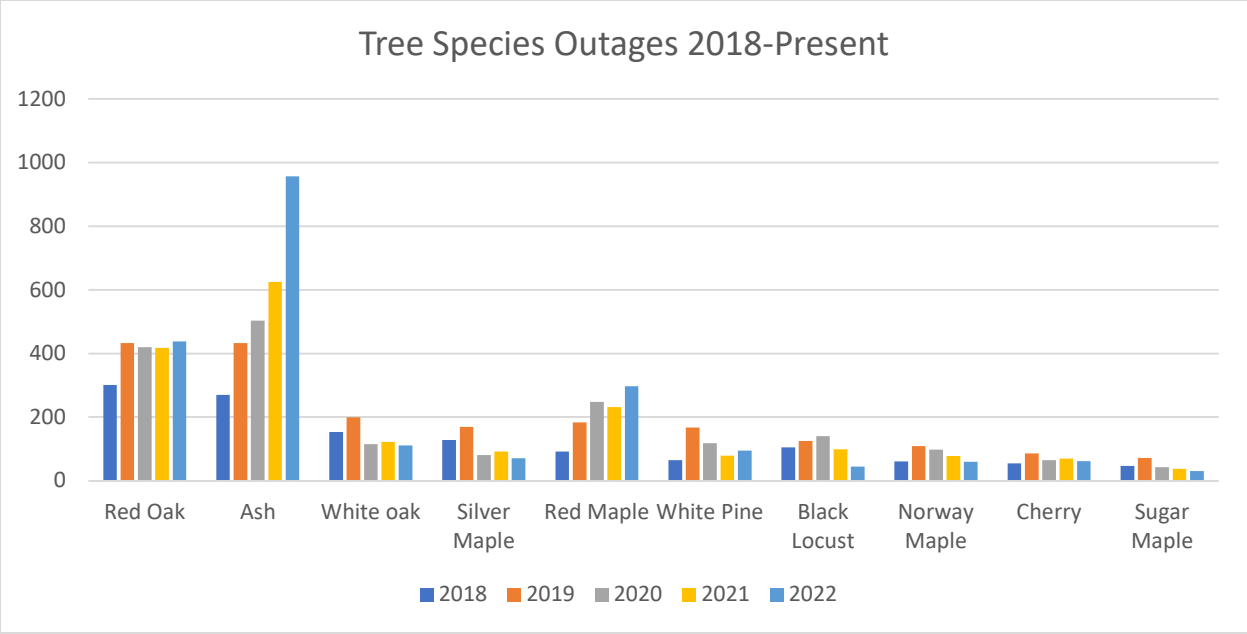
A. The first two initiatives I just mentioned, the Zone 1 and Zone 2 overhang removal programs, both focus on the removal of overhead and not the removal of danger and/or hazard trees. As shown in Table 8 below, the SAIFI decline in 2022 indicates an enhancement. However, the 2019-2021 trend for all tree-caused outages was directionally unfavorable, which appears largely attributable to decimation of off-ROW ash trees as a result of the EAB. The Company anticipates that because of the EAB, the 2019-2021 trend will likely continue notwithstanding the 2022 results. Without continuing the Zone 2 overhang removal work, the trend would be expected to be even more unfavorable.

Table 8



Overall, the results suggest that it is necessary to move forward forcefully on both the Zone 2 and EAB fronts. With respect to the EAB, as shown in Table 9 below, ash trees continue to be the leading cause of outages when ranked by species.

Table 9



Indeed, the confluence of the EAB issue with the timing of the Zone 2 efforts may be blurring the ability to observe more accurately the impacts of the Zone 2 overhang removal. JCP&L intends to continue tracking each category to measure the impacts. But, for now, the attention given to both issues must continue.

Q. Please describe the EAB and its impacts.

A. The EAB is an invasive wood boring beetle, native to eastern Asia, that is highly destructive to the ash species. The larvae (the immature stage) feed on the inner bark of ash trees, disrupting the tree's ability to transport water and nutrients. Due to the lack of water transportation, EAB infested ash trees dry out rapidly, becoming brittle, and

susceptible to failure. Once infected, it is just a matter of time before the ash tree will die. The EAB has been moving west to east, beginning in Michigan in the early 2000's, and was first identified in JCP&L's service territory in 2017.

Thousands of ash trees continue to pose a threat to JCP&L's facilities, causing outages that lead to decreasing reliability and increasing hazards not only for forestry workers but also for line workers. According to the Davey Resource Group,[23] the shear strength of ash wood undergoes a five-fold decrease after the tree is infested by the EAB. This increases the danger of simply working near ash trees.

Q. What is the Company doing to address the EAB?

A. Beginning in 2018, the Company began allocating capital dollars to mitigate against the EAB by targeting removal of ash trees located within Zones 1 and 2. In 2020, this allocation was $1.9 million. Beginning in 2021, as a result of the settlement of the 2020 Base Rate Filing, JCP&L has undertaken such efforts solely under its O&M budget. Nonetheless, the Company's ash tree vegetation management spending has continued to increase from $2.6 million in 2021 to $4.2 million in 2022 (with approximately $3.2 million of the 2022 spend occurring during the second half of the year) and thus, is included in the Test Year. The Company will continue to target ash trees located within Zones 1 and 2, prioritizing those circuits that are performing more poorly first in a cycle year and moving thereafter to the better performing circuits.

[23] As cited in: Invasive borer quickly turns ash trees into widowmakers, Paul Hetzler, October 22, 2017. Available at: https://blogs.northcountrypublicradio.org/allin/2017/10/22/invasive-borer-quickly-turns-ash-trees-into-widowmakers/

Q. Earlier, you referred to proposing to increase the revenue requirement for vegetation management. Can you explain that proposal now?

A. Yes. As previously described, per the settlement of the 2020 Base Rate Filing, the vegetation management expense to be recovered in base rates was capped at $31 million beginning in 2021. As indicated earlier, the Company expended somewhat more than that in 2021 (*i.e.*, $34.9 million) and again in 2022 (*i.e.*, $35.1 million). In practical terms, with the pressures noted above from off-ROW tree-related outages, the EAB, the general increasing trend in the frequency and intensity of weather impacts, the relatively higher tree density of the JCP&L geographic service territory, the added work of enhanced on-cycle work under the VCMP, and the success of the Zone 1 and Zone 2 programs, as well as more recent inflationary pressures, the $31 million annual revenue requirement does not go as far as the same amount went in prior years. For instance, as discussed briefly above in my discussion of O&M, with labor costs increasing between 3% to 4% each year, in New Jersey, the contractor billing rate has also substantially increased over the ten-year period from 2009 to 2020, with steady escalation on such rates since then. Logically, with actual spending outstripping a capped revenue requirement of $31 million for all vegetation management work, including on-cycle maintenance work, driving budgetary planning, the capped amount addresses a decreasing amount of such work. Realistically, and logically, the current revenue requirement level, under the circumstances discussed above, is not adequate to fund the necessary level of work to conduct the effective vegetation management result, including a level of tree removals to meet increasing requirements. The actual and foreseen increased, but unrecovered, O&M budgeted spending for known or reasonably anticipated and specific contingencies is, or would be,

relatively inequitable. Under all these circumstances, the evidence supports that higher levels of spending are necessary and justified. Table 10 below shows budgeted spending for 2024 and estimated budget amounts for the four succeeding years broken out by categories of budgeted and anticipated spending:

Table 10

Anticipated Annual Costs					
	2024	2025	2026	2027	2028
Cycle based program pruning/limited removals [(a)]	$ 32,240,000	$ 33,480,000	$ 34,720,000	$ 35,960,000	$ 37,200,000
Off ROW tree removals	$ 7,280,000	$ 7,560,000	$ 7,840,000	$ 7,080,000	$ 6,280,000
On ROW tree and brush removals	$ 3,120,000	$ 3,240,000	$ 3,360,000	$ 3,480,000	$ 2,300,000
Total	**$ 42,640,000**	**$ 44,280,000**	**$ 45,920,000**	**$ 46,520,000**	**$ 45,780,000**

[(a)] Cycle based program includes cycle maintenance for all curcuits, maintaining Zone 2 overhang removal, removal of limited hazard trees and continued use of 3rd party work planners

Without the significant increased spending proposed above, it is likely that tree-related outages will continue to increase. Funding for this program at the increased levels indicated will enable the Company to reasonably and adequately maintain the clearances already achieved through the Zone 1 and Zone 2 overhang removal, allow the Company to complete an entire cycle of Zone 2 overhang removal, as well as allow the Company to increasingly address the growing number off-ROW trees posing a threat to the power supply lines (within its rights, or with property owner permission, to manage). The Company has a forward-thinking vegetation management program that complies with or exceeds regulatory requirements. The Company continues to focus on the unique heavily forested and rural character of its service territory with a strong and demonstrable commitment to managing vegetation to provide safe and reliable service. The Company will continue to work to reduce the impacts of vegetation within its densely forested service territory on the electric service experience of its customers. The projected spending set

forth in Table 10 above is part of a proposal in this 2023 Base Rate Filing to increase, beginning in 2024, the annual revenue requirement on vegetation management spending from the current capped $31 million by approximately $11 million to a total of approximately $42 million, as discussed in the Direct Testimony of Mr. Mader (Exhibit JC-2) and Ms. Pittavino (Exhibit JC-3). With this increase, the Company is confident it can continue and enhance its existing vegetation management programs.

VIII. STORM RESPONSE PROCESS

Q. How does the Company address storm and emergency conditions that impact the electric system and its customers?

A. In response to such occurrences, JCP&L implements its robust and comprehensive Utilities Emergency Preparedness Organization Emergency Restoration Plan ("E-Plan") for storm response and management. The E-Plan is currently composed of the Basic Plan, Attachments, Annexes, and Appendices. The JCP&L Appendix provides an overview of JCP&L's approach to address drivers, programmatic, and/or regulatory requirements specific to JCP&L and the State of New Jersey and, in that regard, to expand on certain items and information set forth, or outlined, in the Basic Plan portion of the E-Plan. The JCP&L Appendix is scoped for Incidents of escalating intensity and, as appropriate, may be utilized independently or in conjunction with other emergency plans maintained by FirstEnergy organizations (in other State appendices), and with other response partners' plans, to establish an integrated response capability.[24]

[24] For purposes of clarity, the E-Plan described herein is a revised and updated plan, which was finalized in December 2022 to reflect organizational changes.

The E-Plan is also supplemented with the Emergency Restoration Electronic Database (also referred to as the E-Plan Database). The E-Plan Database includes instructions such as job aids, phone listings, qualified personnel and equipment lists, vendor and supplier lists, templates, checklists, maps, contact lists for critical customers, law enforcement contacts, city/county/state Emergency Management agencies, medical facilities, lodging, and other items of a dynamic nature. These items may be referenced by personnel to assist with implementation of the processes, functions, and activities outlined within the E-Plan and in supporting documents that are consistent with the E-Plan and which are maintained by individual departments and organizations. The Company's storm response process is further discussed in the ASPR each year.

Q. Can you summarize recent changes or enhancements to the E-Plan?

A. Yes. As structurally reconstituted, the Base Plan of the E-Plan serves as the foundational document that provides the framework for JCP&L's (and the other FirstEnergy Companies') approach to emergency preparedness, response, and service restoration. State and Company-specific requirements and processes are set forth in appendices. This reorganization of material updated to address more recent regulatory requirements, renders the E-Plan more user-friendly, and, therefore, is expected to become an even more useful tool in storm response and restoration efforts in training and in practice.

This Plan utilizes Emergency Management concepts and principles (including those of ICS) to establish a resilient Emergency Management framework to prepare for, respond to, and recover from incidents. This, in turn, enhances JCP&L's capability to provide safe and reliable service to our customers and to communicate and interact with

various stakeholders as necessary and appropriate, by providing principled-based processes to:

- Implement a comprehensive Emergency Preparedness Program;
- Conduct hazard, vulnerability, and risk assessments for operating and business functions;
- Develop and implement appropriate prevention and risk mitigation strategies;
- Respond to Incidents in a coordinated, standardized, and predetermined manner with appropriate resources;
- Communicate timely with customers and other stakeholders and provide accurate information using voice, internet, media, and other appropriate methods;
- Recover from Incidents safely and expeditiously; and
- Maintain a culture of continuous enhancement.

The E-Plan is not intended to be a detailed emergency checklist or "quick action" guide. Rather, it establishes strategic and global expectations to ensure safe and reliable operations. Again, the storm response process is discussed annually in JCP&L's ASPR and additional information can be found in the latest version thereof.

Q. Do the changes and enhancements to the Company's E-Plan comply with Board regulations and/or applicable orders?

A. Yes. The E-Plan has been designed to comply with all applicable rules and Board directives as well as applicable industry standards, and the Company complies with all Board Orders, directives, and regulations pertaining to such matters. The JCP&L Appendix to the Basic Plan component of the E-Plan incorporates, where appropriate, New Jersey specific regulatory requirements based on Board directives, orders, and regulations.

Q. You mentioned that the Company deployed a new outage management system. Can you explain more about the new system?

A. Yes. As I mentioned previously in my testimony, the PowerOn system has been upgraded to the NMS (which has ADMS functionality). The change was implemented for the West and South FirstEnergy operating companies beginning on or around August 9, 2022, and for JCP&L and the other Eastern FirstEnergy companies on or around August 23, 2022.

The OMS replacement was part of an enhancement, which is an important step towards development and deployment of an overall ADMS, because NMS is not only an integral tool in the storm recovery and restoration process, but also its functionality includes distribution management and advanced applications, which are expected to be utilized fully as part of future implementation projects.

All FirstEnergy utilities use the same outage management system in concert with the E-Plan. This consistency of technology and process facilitates the use of additional DCC dispatchers throughout the FirstEnergy footprint in the affected areas to provide assistance. It also allows for support efforts to be conducted from remote locations.

Q. Does the Company continue to conduct training with respect to its E-Plan?

A. Yes. Among the many individual and group or functional training opportunities, the Company conducts an annual exercise, which incorporates ICS principles and promotes an enhanced understanding of ICS roles and responsibilities. This exercise is conducted each year with advance notice to Board Staff and an invitation to attend and participate. There are opportunities to attend other FE company exercises annually which provides further training on the objectives and processes in the E-Plan. There are also web based training courses on the E-Plan for employees.

Records of training are maintained in a Company database designed for such purposes. The JCP&L Emergency Preparedness Manager also works with the FirstEnergy corporate emergency operations center Director and staff at FESC to review, and as needed, update and revise the E-Plan.

Q. How do the Board's Orders impact the Company's storm process that you have been describing?

A. I see the Board's various storm orders as demonstrating an evolving understanding based on the lessons learned from the New Jersey utilities' storm-related experience. I think of the Board's review and orders as a formal lessons-learned process conducted in the regulatory forum. More specifically, the Board's storm orders have prompted or required changes, additions, adjustments, and the use of new technologies or the application of existing technologies in new ways. In some cases, the Board's storm orders are the drivers of significant and substantial changes in how the Company and other EDCs design and implement their storm recovery and restoration processes (including pre-planning, and pre-staging for more immediate response in anticipation of certain forecasted events) as well as how they communicate this information to their customers, including interactively on the web, and how they otherwise communicate it to public officials, in real-time. It should be recognized, in case it is not obvious, that these measures and new refinements in them are, themselves, cost drivers, that are part of, or additive to the cost of addressing storms. Unfortunately, the costs of pre-staging are incurred even when the forecasted weather does not develop or is of less magnitude than forecasted.

Since 2013, in addition to the approximately 96 recommendations from the Hurricane Irene and Sandy Board Orders, the Board's Order following the Bow Echo storm in 2015, and the twelve storm-related orders from the March 2018 storms, the Board has required the Company and/or the other EDCs to comply with and to develop approaches to accomplish nine recommendations from the Staff's Tropical Storm Isaias Report adopted by the Board.

The Tropical Storm Isaias order included an "undergrounding" study, enhancements to estimated times of restoration, automated messaging, call center peak volume performance, communications to provide more granular information to public officials, as well as surveys to stakeholders on the ice and water process. The Board's directives coming out of Tropical Storm Isaias also require inclusion of an analysis in Major Event Reports of storm hardening projects to enhance resiliency.

As mentioned above, there are, or can be, significant costs and resources associated with compliance with over 110 Board-ordered recommendations, as well as the development, implementation, and continuing compliance with all orders that required changes to existing methodologies or the imposition of new requirements on an ongoing basis, many of which are very difficult to isolate, identify, and quantify. These costs are incorporated and reflected in the Company's capital and/or O&M (as appropriate) annual budgets and spending.

Q. Has the E-Plan received recognition outside of FirstEnergy?

A. Yes. The E-Plan is utilized across the FirstEnergy utility system and is regarded, not only internally, but also externally, as a robust approach to storm responses and restoration. For instance, Edison Electric Institute ("EEI") presents awards twice annually to member

companies to recognize extraordinary efforts to restore power or for assisting other electric companies after service disruptions caused by weather conditions and other natural events. FirstEnergy was awarded the Emergency Recovery Award in 2008 and every year from 2011-2022 by the EEI.[25] EEI also awarded FirstEnergy the Emergency Response Award in 2019 and 2021.

In my opinion, these awards are well-deserved based upon the ongoing effective implementation of the well-designed E-Plan through the ICS structure. Our ICS structure has visible Company leadership support and endorsement. It provides a resilient and scalable response framework that promotes stakeholder involvement in a comprehensive all-hazards approach to planning, preparedness, response, and restoration activities. As will be further discussed, it is a robust, efficient, and effective process, but as evidenced by the accumulating deferred storm costs, it is not an inexpensive one.

In that regard, relative to deferred storm costs, I think I should explain here that, even taking into account the results of the 2020 Base Rate Filing, the Company's storm experience since July 1, 2020 (as to which I will provide some additional insight) has caused the Company to incur additional significant deferred storm costs of approximately $205.2 million, of which, approximately $148.5 million was attributable to Tropical Storm Isaias. As a result, JCP&L's total deferred storm balance was $310.2 million as of

[25] *See*: https://www.prnewswire.com/news-releases/firstenergy-receives-industry-recognition-for-outage-restoration-efforts-301720682.html#:~:text=(NYSE%3A%20FE)%20has%20received,extreme%20temperatures%20in%20June%202022.

December 31, 2022.[26] This increase and the total amount represent prudently incurred costs to prepare for, pre-stage resources JCP&L seeks to recover this amount. Importantly, Mr. Mader's testimony includes a proposal for a shorter amortization for recovery of the deferred storm cost balance. From an operations perspective, I view the proposal as prudent insofar as the quite sizeable, deferred amount acts as a drag on future capital investment in operations since such unrecovered capital could be available each year for further re-investment in the electric system especially when the growth of the deferral outstrips the amortized pace of recovery.

IX. 2020 - 2022 MAJOR STORM RESTORATION

Q. Can you summarize the storm events that impacted JCP&L's service territory during the period 2020-2022 for which JCP&L is seeking recovery of its deferred costs?

A. Yes. Numerous weather events, both major events and smaller non-major events, have impacted the JCP&L service territory during the period 2020-2022.

With respect to those for which storm costs were deferred, in 2020, JCP&L experienced major events in the form of a June Derecho, July extreme heat and thunderstorms, Tropical Storm Isaias in August, and Winter Storms Gail and Harold in December. There were numerous other smaller storms that triggered FE Meteorologist's

[26] As a matter of background, as of June 30, 2020, there had been a storm-related regulatory asset in the amount of total of $305.7 million, which was addressed in the 2020 Base Rate Filing. Allowing for, and notwithstanding, the resolution adopted in the Board's Order in that proceeding, as of December 31, 2022, the current storm-related regulatory asset balance stands at $310.2 million, which now exceeds the amount addressed in the 2020 Base Rate Filing. The approximate net increase since June 30, 2020 of $4.4 million includes additional storm costs of $205.2 million less amortizations of $70.7 million as of December 31, 2022. ***See*** Direct Testimony of Carol A Pittavino, Exhibit JC-3 in which she discusses Adjustment 15.

weather alerts for every month from April through July and October through December. These included Tropical Storm Fay and Winter Storm Zeta.

In 2021, significantly, the remnants of Hurricane Ida ("Ida") impacted JCP&L's service territory. Ida intensified to hurricane strength storm on August 27, 2021, which impacted the Gulf Coast of the United States. The remnants of Ida began impacting New Jersey on September 1, 2021, bringing with it strong winds, reports of tornadoes, and heavy and sustained rainfall. These thunderstorms produced heavy rainfall and wind gusts of approximately sixty miles per hour, causing outages to 91,904 customers. These circumstances affected a total of 262,709 customers. In the Northern Region, 106,293 customers were impacted, and in the Central Region, 156,416 customers, or 23.69% of customers were impacted. All customers were restored by September 16 at 0541. I will also mention that the costs associated with storm preparation and response for remnants of Hurricane Ida was approximately $10.5 million, with $5.65 million being O&M and the remainder capital.

Also, in 2021, in addition to the remnants of Hurricane Ida, JCP&L experienced other major events: a weather-related state of emergency ("SOE") in January and a Bow Echo and Tropical Storm Elsa in July. JCP&L provided mutual assistance as noted above during Ida.

In 2022, major events included a March combined wind and snowstorm and Winter Storm Elliott, which occurred in December and impacted approximately 70,000 customers as a result of a strong Artic front that included high winds and single digit temperatures.

Q. Can you discuss one of these recent storms as an example of the implementation of the Company's storm recovery and restoration processes?

A. Yes. Initially, I think that a description of Tropical Storm Isaias will help to explain the extensive efforts undertaken to respond to major storms implementing the E-Plan and using the ICS structure. Tropical Storm Isaias also provides an opportunity to demonstrate how JCP&L has prudently incurred the costs that were necessary in planning for, responding to, and replacing facilities and equipment damaged as a result of major storms and making permanent repairs. As I have discussed, the Company has properly utilized its robust E-Plan and ICS structure to address Tropical Storm Isaias and other major storms, meeting applicable industry and regulatory standards. Lastly, details regarding the storms I will mention were provided to the Board in separate Major Event Reports for each such storm. In addition, summaries of such storms can be found in the ASPR for the year of occurrence.

Q. Please describe the impact of Tropical Storm Isaias on the Company's system.

A. Tropical Storm Isaias affected the JCP&L service territory during the period of August 4 through August 13, 2020, affecting approximately 788,000 customers. On Monday, August 3, 2020, New Jersey Governor Philip D. Murphy issued Executive Order ("EO") No.174, declaring a SOE in the State of New Jersey to take effect on August 4 at 0500. According to the EO, the National Weather Service forecasted that Hurricane Isaias would impact New Jersey beginning on August 4, bringing the potential for severe weather conditions including hurricane force winds and heavy and sustained rainfall of up to four to six inches. Together with the weather systems that followed and the initial impact of the storm, through the time the SOE was lifted on August 13 and JCP&L returned to normal

operations, a total of 1,026,798, over 90%, of JCP&L's 1.1 million customers were affected.

In the afternoon of Tuesday, August 4, Tropical Storm Isaias swiftly passed through the JCP&L service territory producing widespread rainfall of four to seven inches, with some areas exceeding seven inches, and wind gusts upwards of sixty-five miles per hour. After the most severe rain and thunderstorms had passed, bucket trucks were grounded until wind gusts in excess of thirty-five miles per hour subsided.

Of note, on August 3, flood mitigation measures (as required by Board Order) were implemented at multiple substations across the JCP&L service territory. JCP&L experienced no flooding at any of its substations from Tropical Storm Isaias.

Q. Please describe the damage experienced during Tropical Storm Isaias.

A. As mentioned above, Tropical Storm Isaias affected approximately 788,000 customers, and through the period when the SOE was lifted on August 13 and JCP&L returned to normal operations, 1,026,798 JCP&L customers were impacted. This was the second most damaging storm in JCP&L history based upon the number of customers affected.

Approximately 400 distribution circuits, about 25% of JCP&L's total circuits, experienced a complete circuit lock out. Tropical Storm Isaias caused far more significant damage to JCP&L's transmission and sub-transmission system than recent major weather events, including Winter Storms Riley and Quinn in 2018. Over 92% of distribution customers in JCP&L's territory are supplied from the 34.5kV sub-transmission system. A total of 114 lines (or 58% of total miles) of that sub-transmission system were impacted by the storm. As a result, nearly 400,000 customers experienced an outage due to sub-

transmission damage alone. Restoration was further complicated by loading issues as the 34.5kV network was being reestablished, which required some temporary manual load shed events.

As part of the restoration process from Tropical Storm Isaias, JCP&L addressed approximately 8,800 locations where tree damage was discovered. The combination of devastating wind and heavy rainfall in a short duration caused many trees and limbs to break. Based on the hazard and damage assessments, most of the outages caused by Tropical Storm Isaias were due to tree damage. Additionally, approximately 70% of tree related orders were caused by off-ROW trees.

Q. Did JCP&L experience any complications during restoration efforts regarding Tropical Storm Isaias?

A. Yes, very much so. First, and foremost, Tropical Storm Isaias occurred during the beginning of the COVID-19 pandemic. As a result of the pandemic, JCP&L had to take extraordinary measures to keep crews and customers safe by limiting exposure and contact. These extraordinary measures included isolating crews and providing separate rooms for lodging, providing additional personal protective equipment, including masks, gloves, and hand sanitizers, to mitigate the spread of a COVID occurrence. JCP&L tested all crews who provided assistance.

Another complication during Tropical Storm Isaias was the high winds that prevented crews from starting restoration in accordance with best practices safety recommendations. After the most severe rain and thunderstorms had passed, bucket trucks

were grounded until wind gusts in excess of thirty-five miles per hour subsided, thereby necessarily delaying restoration efforts.

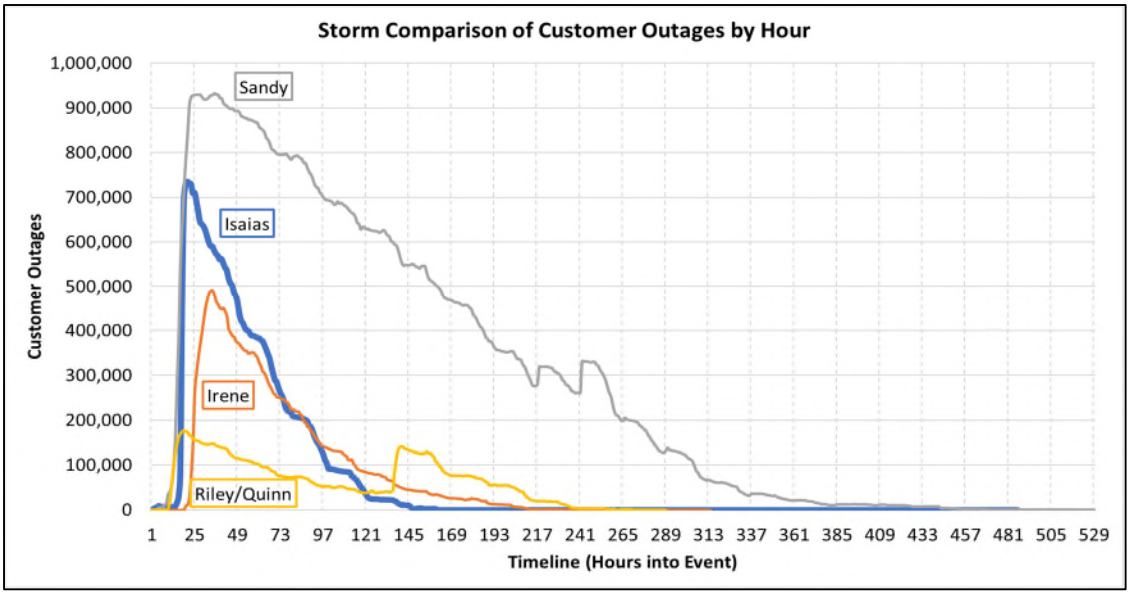
In addition, electric utilities, including JCP&L, are dependent upon meteorological forecasts and outage volume models to determine potential outage impact and need for additional resources, both people and equipment. Decisions are made based on the information available. FirstEnergy Meteorological Services ("FE Meteorologists") at FESC began tracking Hurricane Isaias on July 29 as the weather system formed and issued preliminary weather alerts beginning on July 31 regarding the potential impact of the weather system. The weather system made landfall as a Category 1 hurricane in southern North Carolina late on August 3. It then began to accelerate northward while remaining inland of the Atlantic coast. JCP&L ran the Outage Volume Model ("OVM") based on the forecasted weather, which predicted a maximum of 449,312 customers would be affected by the unusual inland acceleration of the now tropical storm event. This estimation proved to be low. This can mainly be attributed to the historically low number of similar large and widespread storm events for which comparable weather data was available as inputs to the OVM.

Q. How does Tropical Storm Isaias compare to other large restoration events that JCP&L has experienced?

A. Tropical Storm Isaias was the first large-scale event experienced by JCP&L since Riley-Quinn, and it was second only in scope and damage to Hurricane Sandy in 2012. As the graph below demonstrates, while damage was greater in Tropical Storm Isaias than Riley-Quinn and Irene, JCP&L safely restored customers in less time.

Based on the below restoration curves in Table 11, all customers were restored in approximately six days. Another storm of similar magnitude was Hurricane Irene, experienced in 2011, with approximately 500,000 customers affected, which took approximately eight days to restore customers. I believe this enhancement in performance can be attributed to JCP&L's 1200+ employees' experience, technology enhancements, as well as storm readiness and restoration process enhancements made over the past 10 years.

Table 11



Q. Did JCP&L incur extensive capital costs and O&M expenses because of Tropical Storm Isaias?

A. Yes. As indicated earlier, the capital costs associated with storm preparation and response for Tropical Storm Isaias amounted to $36.9 million. The associated deferred (i.e., not including straight-time employee labor associated with the storm) O&M costs were $148.5 million. A post-event evaluation by the Board indicated that JCP&L's performance was

generally in compliance with the prior applicable Board orders and directives. JCP&L was found to have adequately utilized its in-house meteorologists and weather modeling scenarios to make the appropriate preparations for the storm. As compared to the other New Jersey EDCs, JCP&L had the highest number of customers impacted. Also, JCP&L had a better restoration pace when compared to previous similar-sized events in its service territory. JCP&L was able to restore approximately 86% of customers within 72 hours, which was comparable with the speed of restoration of the other New Jersey EDCs, which were not as severely impacted by the storm.

Q. In your experience, and to your knowledge, has any of the damage or restoration times addressed during major events, been exacerbated by a failure of the Company to fully implement its I&M programs?

A. No. The Company's I&M programs were fully implemented during the years in question. There was no failure of the Company to fully implement its I&M programs, including its vegetation management programs. Accordingly, since there were no such failures, none could have contributed to the damage or caused any restoration delays during the years in question.

Q. Do you have anything you wish to add before moving on to additional topics?

A. Yes. I think it may be helpful to reiterate that the Company's storm restoration processes are well-conceived, and effectively managed and implemented by the Company's dedicated workforce, as discussed above. But, storm preparation, response and recovery are not inexpensive propositions and, under appropriate circumstances, contribute to increasing deferred storm costs, I think it is necessary for me to repeat that these deferred

amounts, in my view, represent prudently incurred costs, which JCP&L seeks to recover under Mr. Mader's proposal (Exhibit JC-2), which includes a shorter amortization for recovery of the deferred storm cost balance. From an operations' perspective, I think such proposal, could make additional capital available each year for further re-investment in the electric system especially when the growth of the deferral outstrips the amortized pace of recovery.

X. DISTRIBUTION SYSTEM RELIABILITY PERFORMANCE

Q. Please discuss the reliability performance of JCP&L's distribution system.

A. Let me begin by saying the Company's annual reliability performance is described and discussed in great detail in the ASPRs, which are filed each May with the Board, in accordance with applicable regulations. The Company's ASPR for 2022 will be filed with the Board by May 31, 2023, as required by such regulations.

During the 2019-2021 period, JCP&L's regional reliability performance was better than the Board's required minimum reliability standards for SAIFI and CAIDI,[27] with the exception of the Northern Region's 2020 SAIFI performance. As I will discuss further, the Company's analysis suggests that the Northern Region's 2020 SAIFI appears to be largely attributable to the impact of Minor Weather Days. While 2021 performance was

[27] It may be helpful to provide several definitions at this juncture in order to assist in promoting understanding. CAIDI means "Customer Average Interruption Duration Index." CAIDI depicts average outage duration per customer. SAIFI means "System Average Interruption Frequency Index." SAIFI calculates the frequency of outages on a customer basis. SAIDI means the "System Average Interruption Duration Index." SAIDI (which is measured in time – usually minutes or hours) provides a view of outage duration on the system. In our case, the measure is in minutes. SAIDI is calculated by dividing the sum of all customer outage durations by the number of customers served. Thought of another way, it is the product of multiplying CAIDI by SAIFI. By using SAIDI in parts of our discussion, we can better describe, explain and consider the overall system impacts of events or circumstances under certain conditions.

somewhat improved, the 2022 SAIFI performance has fallen below minimum requirements for SAIFI in both the Northern and Central Regions, requiring additional analysis to obtain a better understanding of the drivers of this result.

Tables 12A and Table 12B below reflect the respective assigned benchmark and minimum standards in effect 2020 through 2022.

Table 12A

	CAIDI				
	Benchmark Reliability Level	**Minimum Reliability Level**	**2020 Actual (Minutes)**	**2021 Actual (Minutes)**	**2022 Actual (Minutes)**
JCP&L	N/A	N/A	115.1	113.98	119.4
JCP&L-Northern	128	151	131.5	130.84	145.5
JCP&L – Central	101	110	98.6	100.79	99.9

Table 12B

	SAIFI				
	Benchmark Reliability Level	**Minimum Reliability Level**	**2020 Actual (Outages)**	**2021 Actual (Outages)**	**2022 Actual (Outages)**
JCP&L	N/A	N/A	1.2	1.22	1.44
JCP&L-Northern	1.18	1.35	1.46	1.3	1.50
JCP&L – Central	1.01	1.22	1.02	1.16	1.41

Q. Does JCP&L's performance comply with the BPU's regulatory requirements for reliability?

A. As mentioned above, in 2020 JCP&L's Northern Region's SAIFI failed to meet the minimum performance requirement. After meeting all requirements in 2021, the Company's 2022 reliability performance, when finally reported in May 2023, is expected to indicate that both the Northern and Central Regions did not meet their 2022 SAIFI minimum performance requirements. As will be discussed below, based on a closer analysis of this experience, there are some noteworthy contributors to the anticipated result that provide a clearer perspective and understanding of the 2022 SAIFI performance results.

Q. Has the Company reviewed and considered the significant impacts to reliability performance during this period?

A. Yes. Based on recent experience with Minor Weather Days, JCP&L started its analysis there to better understand the 2022 experience. To begin, JCP&L's SAIFI performance in 2020 indicated a directionally increasing trend showing an approximately 77% increase in Minor Weather Day impact to SAIFI as compared to the period 2015-2017. While the Company experienced an increase of one day in the number of Minor Weather Days in each of the years 2021 and 2022, as compared to 2020, the contribution of Minor Weather Days to the Company's SAIFI performance increased only slightly in 2021 but decreased in 2022. Similarly, the impact of Minor Weather Days on SAIDI also decreased during the 2021-2022 period. As the results for this period are contrary to recent trends, there was a need for further analysis to understand the drivers.

Q. What do you mean by "Minor Weather Days"?

A. JCP&L utilizes the concept of Minor Weather Days to distinguish between a (i) blue-sky day, where there is no adverse weather or, nothing beyond the typical inclement weather,

which is not excluded from the calculation of SAIFI and CAIDI and (ii) a major event, which the BPU defines in its current regulations, and which is excluded from the calculation of SAIFI and CAIDI. FirstEnergy, including JCP&L, utilizes the concept of Minor Weather Days internally to indicate periods when either the entire service territory or specific operating regions/districts experience adverse weather conditions, which cause customer outages that are beyond typical inclement weather, but do not reach the threshold to qualify as a major event. The concept of a Minor Weather Day is used by FirstEnergy, including JCP&L, to better understand the role and impacts of weather variation on reliability.

Q. Is a Minor Weather Day just a subjective determination?

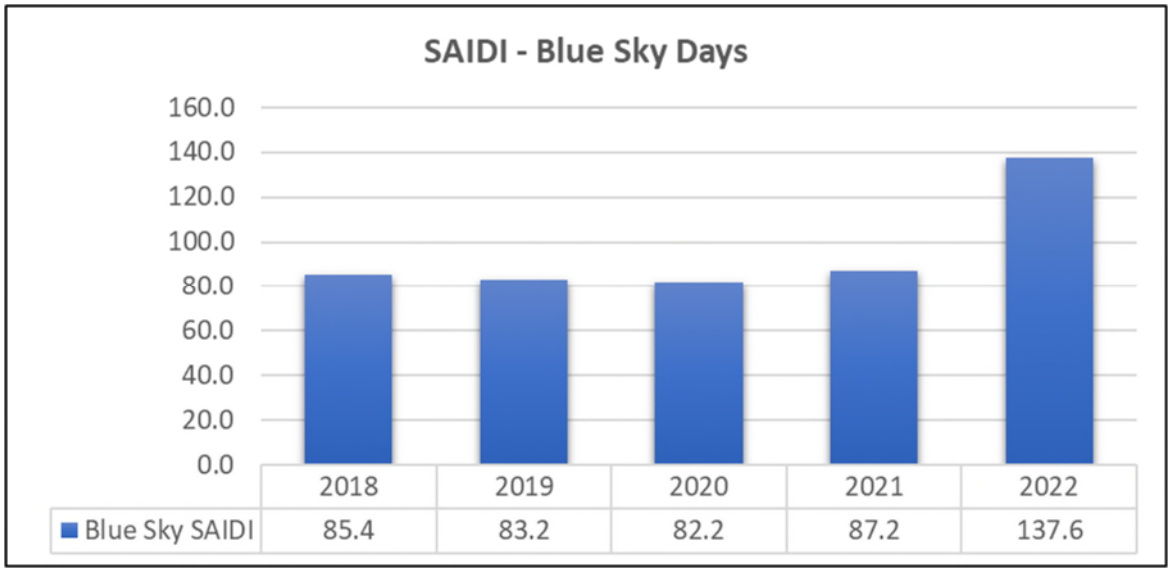
A. No. JCP&L has developed criteria for the designation that helps to distinguish the minor weather day from a blue-sky day. The criteria for retrospectively designating the weather experience over a period of time as a Minor Weather Day includes: (A) winter precipitation, meaning (i) ice or freezing rain of 0.25 inch or more within a 24-hour period; and (ii) four inches or more of snow within a 24-hour period (wet or dry snow); (B) wind speeds 40 mph or higher; and/or (C) lightning strikes greater than or equal to ten strikes.

Q. Why does the Company use the Minor Weather Days concept?

A. As I stated earlier, the concept assists in better understanding the impacts of weather variability on reliability performance. Moreover, it provides a context and a tool for better understanding the drivers of reliability performance. For instance, this type of analysis provides insight about the Company's blue sky day SAIDI performance, which remained

relatively stable during the period of 2018 through 2021 although not for 2022, as seen in the table below:

Table 13



Q. Above, you stated that "the Company's blue sky day SAIDI performance, … remained relatively stable during the period of 2018 through 2021 although not for 2022." Can you explain the Company's view of the 2022 data?

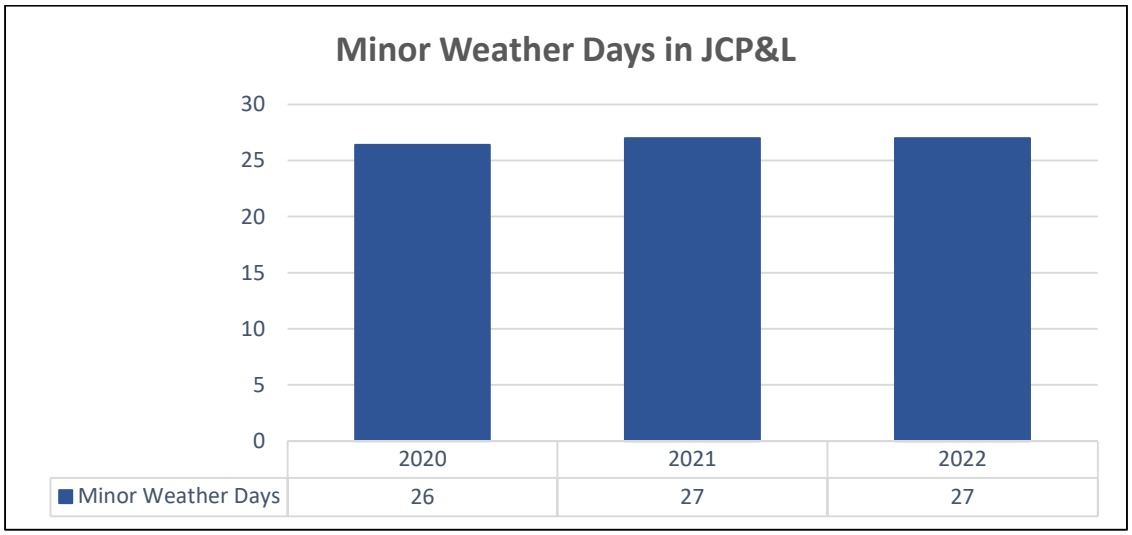
A. Yes. A decrease in Minor Weather Day SAIDI and SAIFI in the same year was directionally the opposite of the longer-term performance trends we had seen in prior years from 2016 through 2021. A directionally opposite Minor Weather Day SAIFI/SAIDI experience in any given year (or even in consecutive years) may not be surprising since weather trends span longer periods of time than the window relevant to this analysis. Variability in individual years does not necessarily contradict longer-term trends, such as those associated with the influence of climate change. However, the slight increase in Minor Weather Days accompanied by a decreased contribution to JCP&L's 2022

SAIFI/SAIDI reliability performance experience, while not expected from a trending perspective, indicated the Minor Weather Days were not the driver for the 2022 SAIFI and SAIDI performance. Therefore, a closer examination of the Company's 2020-2022 Blue Sky Day reliability experience was in order.

Q. Were SAIDI comparisons for Minor Weather Days to Blue-Sky Days helpful to the analysis?

A. Yes. Although increasing in 2021 by one day and remaining the same in 2022, JCP&L's number of Minor Weather Days[28] remained relatively stable during the same (2020-2022) period as shown in the next table below:

Table 14



The following tables illustrate the number of Minor Weather Days JCP&L experienced during this time on a regional basis (Table 15) as well as the SAIDI impacts

[28] JCP&L Minor Weather Days includes events qualifying as a "Minor Weather Day" as discussed earlier, in both JCP&L's Northern and Central Regions on the same day. Minor Weather Days occurring in only one JCP&L Region are not included in Table 15 but are shown in Table 16.

for Minor Weather Days (Table 16) on the Company on an overall basis (as opposed to the individual regional results, which show the Central Region experiencing an increase and the Northern Region a decrease).

Table 15

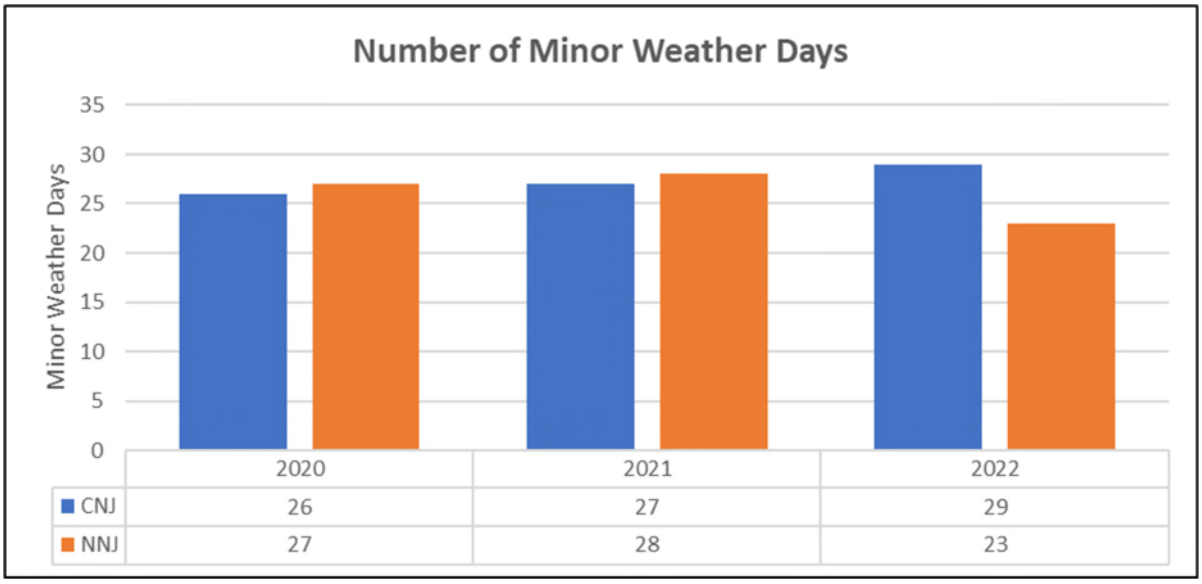
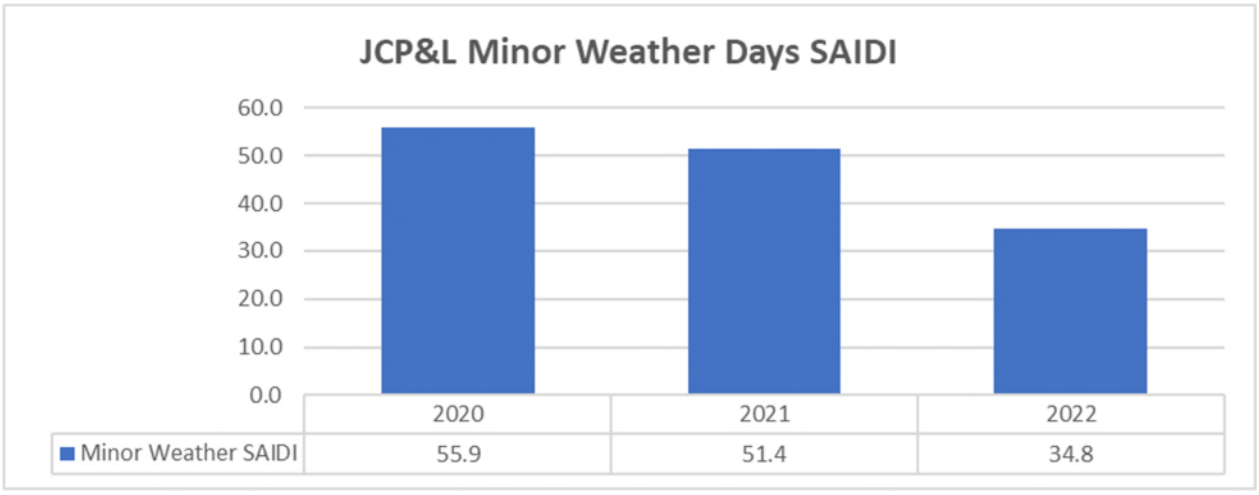


Table 16



However, as shown in Table 16, the SAIDI impact of Minor Weather Days decreased (slightly in 2021 and more significantly in 2022). Consistent with my testimony

in the 2020 Base Rate Filing, through 2020 the data suggested that the increased SAIDI for Minor Weather Days correlated with an upward trend in both the frequency and severity (as reflected in the SAIDI per day data) of patterns of Minor Weather Days since 2016. However, the data for 2021 and 2022 presented a variance in the trend. While the slight reduction in the Minor Weather Day contribution to SAIDI and SAIFI in 2021 was not remarkable, the reduction in 2022 of 12.1 (that is, from 51.4 in 2021 to 39.3 in 2022) was significant.

In 2022, Minor Weather Days impacted JPC&L, but to a lesser degree than in 2020 and 2021. In 2022, Minor Weather Days contributed just under 40 SAIDI minutes to JCP&L's reliability. In 2020 and 2021, the SAIDI contribution from Minor Weather Days was over 50 minutes. This data indicates that Minor Weather Days are not the driver of SAIFI and SAIDI performance in 2022, but instead that performance on Blue-Sky Days was declining. This finding then caused the Company to undertake a review of the non-weather events that impacted JCP&L's SAIFI and SAID performance on Blue-Sky Days. Our analysis showed that there were a number of non-weather factors that were drivers of the 2022 JCP&L Blue-sky day reliability experience in 2022 (as shown in Table 17 below). On further examination, the causes of the outages were not systemic in nature, but rather extrinsic or temporary. Table 17 looks at SAIFI and corroborates the discussion above regarding SAIDI during the period 2020-2022. Table 18 looks at the same data on a regional basis and Table 15, as provided above, shows the number of Minor Weather Days in each region, as to which it must be noted that Minor Weather Days for the Company do not include any Minor Weather Days that only occurred in one region.

Table 17

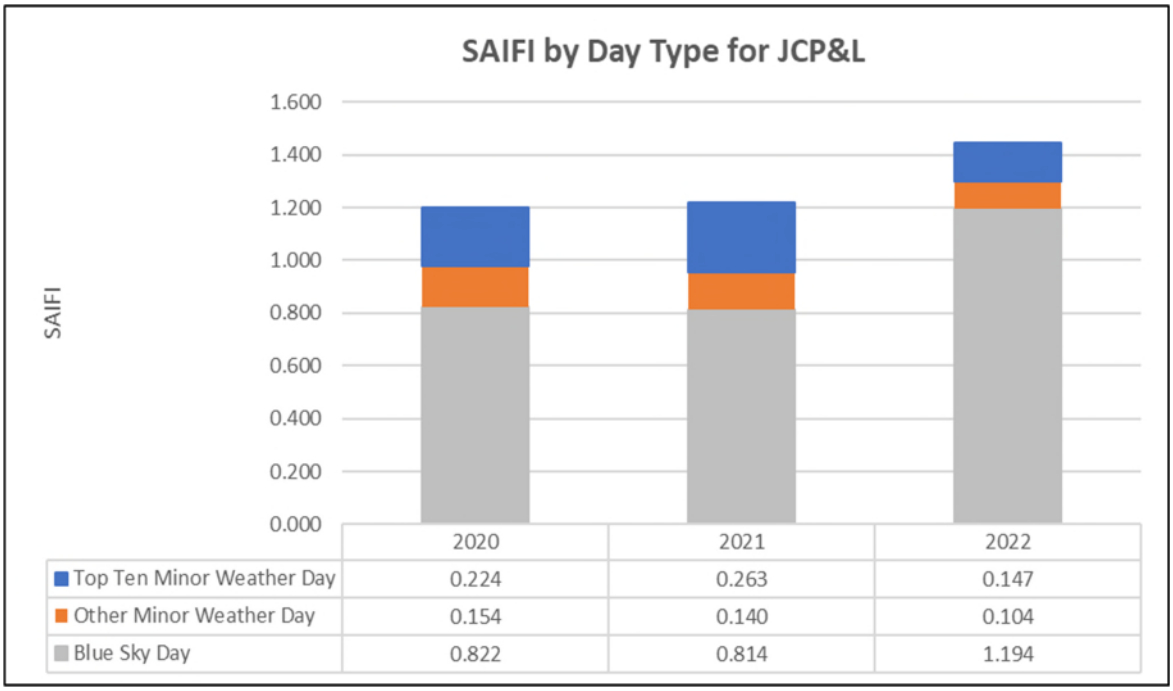
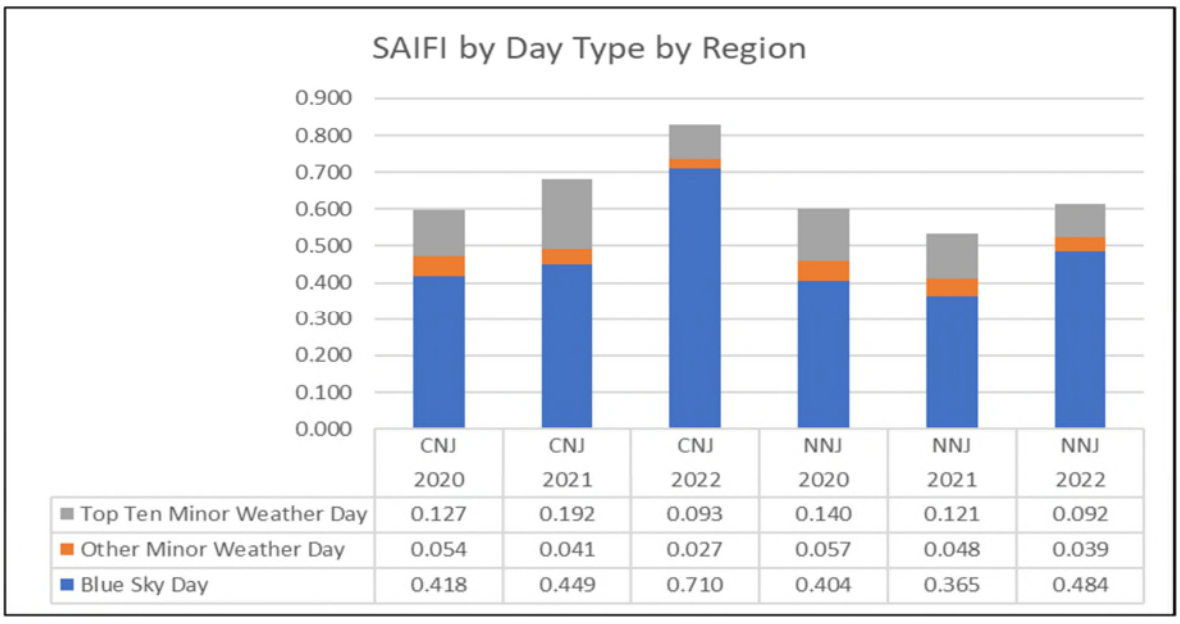


Table 18



Closer examination revealed, most importantly, several non-weather events that contributed to the Company's 2022 SAIDI and SAIFI performance results.

For instance, approximately 21,200 customers were affected by two customer equipment failures resulting in approximately 1,350,000 customer minutes of interruption ("CMI"), and a 1.19 contribution to SAIDI and 0.019 to SAIFI).

Moreover, approximately 15,600,000 CMI, affecting approximately 180,400 customers (contributing 13.75 minutes to SAIDI and 0.16 to SAIFI) were caused by twelve transmission-related events with the majority of the CMI related to four transmission enhancement and scheduled maintenance projects that created unplanned interruptions related to circuit configuration and switching issues. These unique circumstances limited the Company's options to tie to neighboring circuits at the time of the failures, thus causing relatively extended outages.

Q. Can you provide some additional examples?

A. Yes. on October 19, 2022, a switch designated as the D33 at the Company's Oceanville substation faulted, taking out a busbar at the substation. A busbar is an electrical junction used for collecting electric power from the incoming feeders and distributes them to the outgoing feeders. At the time of the fault, another busbar at the Oceanville substation was out of service on a clearance related to transmission project work. These circumstances resulted in a sustained outage to approximately 63,000 customers. While the outage was relatively short in duration, it did affect many customers and negatively affected JCP&L's reliability. There were a number of these type events in 2022. While this type of transmission work on the system will ultimately enhance the reliability in the short and long term, it does create additional, short-term risk and can have a negative effect on

JCP&L's immediate reliability performance. In our view, that was one of the contributors to the Company's SAIFI performance in 2022 in both of its regions.

In addition to the above-mentioned outage involving the D33 switch, on November 11, 2022, a piece of equipment failed at the Atlantic substation and a part of the transmission system in the area was in abnormal configuration due to an ongoing capital project. The combination of these factors resulted in a service interruption to 33,000 customers.

On November 25, 2022, there was a tree-caused fault on the Y701 line. The other sub-transmission line feeding substations in the area was purposefully disconnected on a clearance to accommodate a capital construction project. Being unable at the time to switch the load from the Y701 line because of the clearance on the other line to accommodate the capital construction project, the tree-caused fault resulted in a sustained outage to approximately 14,000 customers.

Since September 2022, JCP&L has experienced a number of these kinds of outages, which have affected over 120,000 customers. For instance, one of the major contributors has been outage events on transmission and sub transmission lines, and at substations, which were complicated by having the electric system in an abnormal configuration in order to these ongoing capital projects intended to bring long-term system enhancements. While the capital work will ultimately enhance the reliability and resiliency of the system, the abnormal configuration created challenges in restoring or delaying the restoration of customers.

Q. What does this analysis tell us about the Company's reliability performance?

A. While the Company does perform risk analysis and does not take any unnecessary or imprudent risk to complete the capital project work to enhance the system, certain safety and technical steps (such as clearances and deployment of mobile transformer units as necessary) are required to perform the work. These construction-related configurations are necessary to the work but create temporary risk exposures to inadvertent events that can impact reliability to more customers and/or for longer durations than would otherwise be the case during normal system configuration.

Q. What does this correlation mean to the Company's reliability performance?

A. Let me begin by being very clear that this analysis is not about making excuses for the Company's reliability performance in 2021 and 2022. Analysis through 2021 continues to shed light on the Company's statistical reliability performance from a Minor Weather Day perspective. Where Blue Sky SAIDI remains relatively flat through the period, the increasing trend relative to Minor Weather Days, which is not inconsistent with concerns expressed relative to climate change (as discussed earlier in my testimony), indicates that the frequencies and severity of Minor Weather Days (over which the Company has no control) negatively impacts reliability significantly. For 2022, while the data is directionally inconsistent with this trend, the data indicates that there were non-weather circumstances that contributed, that are not expected to be persistent or continuing but that were of sufficient (i) magnitude relative to the number of customers, (ii) frequency, and (iii) duration to make significant contributions to SAIDI and SAIFI performance in 2021 and 2022.

Q. How significantly?

A. Let me discuss this in two parts. First, I will discuss the Minor Weather Days' contributions and impacts. Second, I will discuss the other types of contributor incidents. Through 2021, the best way to show the significance, continues to be to examine the contribution of the Minor Weather Days to the Company's SAIFI performance. SAIFI, which calculates the average frequency of outages on a per customer basis, provides insight into the average customer's experience. Looking at the Minor Weather Day data for 2020, it appears that the SAIFI for Minor Weather Days accounted for 34% (or 0.497 occurrences) of the Northern Region's total SAIFI and 30% (or 0.308 occurrences) of the Central Region's total SAIFI.

Looking at the Minor Weather Day data for 2021, it appears that the SAIFI for Minor Weather Days accounted for 32% (or 0.169 occurrences) of the Northern Region's total SAIFI and 32% (or 0.233 occurrences) of the Central Region's total SAIFI. In the case of Northern Region, it represented a small improvement (*i.e.*, decrease) over the prior years' experience and in the case of Central Region it was small increase (or performance decline) over the prior years' experience.

In 2022, similar to what was discussed above as to SAIDI, Minor Weather Days impacted the Company's SAIFI performance accounting for 14% (or 0.120 occurrences) of the Northern Region's total SAIFI and 21% (or 0.131 occurrences) of the Central Region's total SAIFI. In the case of Northern Region, this represented a performance enhancement (*i.e.*, statistical decrease) over the prior years' experience and in the case of Central Region it was also a statistical decrease (or performance enhancement) over 2021.

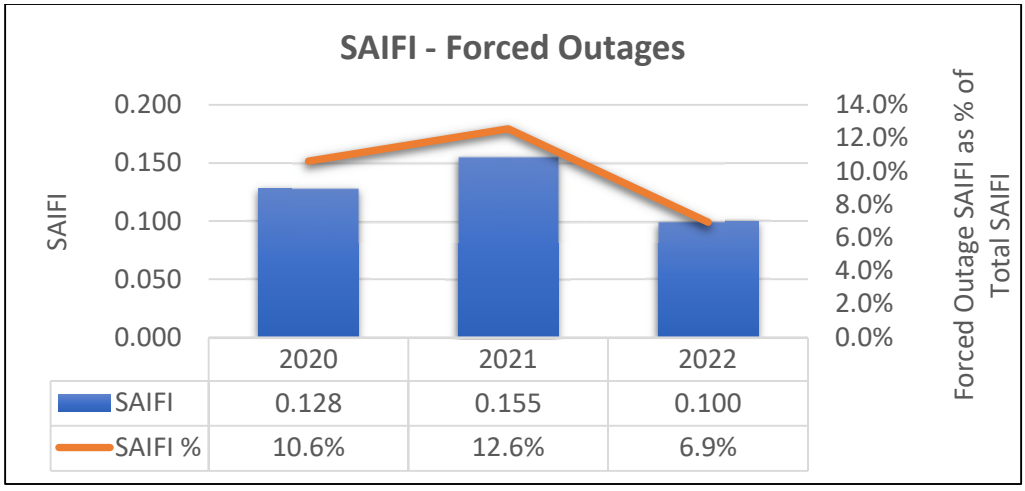
Q. What about the non-weather events described and discussed above?

A. In addition to the Minor Weather Day contribution, the non-weather-related events reviewed above, which we would view as atypical in our experience (due to the size and substance of the capital projects underway) have made a significant contribution to the portion of SAIFI performance exceeding minimum standards. Analyzing the significant reliability drivers for each region there are some items worth noting. In the Northern region service territory, there were nine events that if they had not occurred or their impacts had been excluded from the yearly statistics, the region's SAIFI would have been 1.31 which would have been below the minimum target of 1.35. These reliability drivers largely consisted of the customer-related failures noted above, as well as transmission interruptions due to capital project work, maintenance, lightning, and equipment failures. A similar situation can be noted in Central Region as well. Nine reliability driving events consisting of transmission-related interruptions due to project work and maintenance, equipment failures, lightning strikes, as well as a large distribution underground cable failure, all contributed to an increase of 0.19 SAIFI. If these CNJ events had not occurred or had been excluded from the yearly statistics, the minimum regional SAIFI target of 1.22 would have been achieved. The data informs the understanding of what actually occurred, the likelihood that it will continue to occur and the degree to which immediate experience (including ongoing and new transmission capital projects) may lead to longer-term performance enhancement. The data also provides insights that can be used to inform and strengthen planning, coordination, management and communications regarding such circumstances.

Q. Does the Company see any other changes that provide insight regarding its reliability performance?

A. Yes. JCP&L and all of FirstEnergy continue to prioritize safety above all else, that of its employees, its customers, and the general public. In this context, I think it is relevant to mention that JCP&L continues to see the number of forced outages taken to de-energize equipment before making repairs, thereby reducing contact exposure, is at a relatively consistent level, although in 2022 it was at its lowest level since 2015. As a matter of enhancing the focus of our employees on safe work practices, the Company has worked with its line and substation employees to provide a wider range of latitude within which to use their practical judgement in determining whether and when to work a line or substation condition in an energized or non-energized mode. JCP&L has subsequently noticed that this increased flexibility in favor of enhancing already-safe work practices has its own pronounced impact on SAIFI as shown in the following Table 19.

Table 19



Clearly, this step towards increased line and substation worker safety has a necessary, albeit adverse, impact on reliability performance. In addition, it is important to consider the potential or actual impact of the COVID pandemic on the Company's reliability performance, especially in the peak COVID years of 2020 and 2021 – even into 2022.

Q. Can you please elaborate on the Company's COVID-19 experience and its impact on reliability?

A. Let me begin with some background. In 2020, the Congressional Research Service projected, relative to reliability, that:

> **Electric Reliability**
>
> … the North American Electric Reliability Corporation (NERC) … noted increased reliability risks in [the] Spring 2020: potential workforce disruptions due to illness and quarantine, potential supply chain disruptions, and increased cybersecurity risks due to more teleworking employees. According to NERC, these elevated risks are likely to continue throughout the summer, and new risks may emerge. Potential new Summer 2020 risks include electricity supply disruptions caused by deferred maintenance … Additionally, pandemic protections might cause utilities to take longer to restore power following emergencies such as hurricanes (the Atlantic hurricane season began on June 1) or wildfires.[29]

Fortunately, many, if not most, of these concerns and sensitivities did not materialize, or fully manifest themselves, at significant levels during the pandemic. However, the measures taken to protect employees in accordance with CDC guidance did, in JCP&L's experience, result in minor impacts on reliability performance. For example,

[29] COVID-19: Potential Impacts on the Electric Power Sector, Updated June 12, 2020, Congressional Research Service (CRS). Available at: https://crsreports.congress.gov/product/pdf/IN/IN11300#:~:text=Potential%20impacts%20over%20the%20coming,or%20reduced%20industry%20investment%20activity.&text=Electricity%20demand%20is%20determined%20mainly%20by%20weather%20patterns%20and%20economic%20activity

JCP&L had its physical workforce work in pods. This means that employees worked in the same groups, during normal business hours and for callouts. In many cases, this meant calling out workers in groups instead of by opportunity list, which in some cases added time to the callout process. Also, during the height of the pandemic, JCP&L avoided teaming employees from different areas so, at times, this would add time while local employees were being called out as opposed to moving resources from one shop to another. In addition, JCP&L's measures were conservative to minimize COVID-19 exposure. If there was any risk of exposure, employees were sent home to ensure others in the workforce were not exposed. This safety measure, however, did reduce worker availability and, at the pandemic's worst, increased response times to outages in some instances. Fortunately, the Company has returned to pre-pandemic operations in terms of worker availability and work processes. While variants of the COVID-19 virus continue to impact our workforce, I believe that the mostly anecdotal COVID-related impacts on reliability should be much reduced if not eliminated as JCP&L moves into 2023.

Q. Is the Company planning any new projects that it expects will address and enhance reliability performance?

A. Yes, the Company would like to highlight two projects that, while they are transmission and sub-transmission projects, are expected over the next five years to positively impact JCP&L's distribution reliability performance. The first project will upgrade 295 34.5kV line terminals by replacing the existing single electro-mechanical relay scheme with standard Schweitzer SEL-421 dual protection solid-state relays with reclosing and breaker failure. This project will focus on lines currently without auto-reclosing, lines currently

without solid-state relays, and critical lines with earlier vintage technology relays that operate more frequently. Currently, when a 34.5 kV without auto-reclosing trips a transmission system operator must manually sectionalize the line. Because an outage less than 5 minutes is considered to be a "momentary outage", the time spent on this manual process often causes what would have been a momentary outage to become a sustained outage that has a greater impact on reliability performance. Since there is SCADA to the breakers, typically it is not necessary to dispatch a truck and crew, but it does take over five minutes for an experienced operator to sectionalize and restore the line. With the installation of auto reclosing, this work will be completed in approximately 90 seconds. The project is scheduled to be completed in 2029.

The second is the Central New Jersey Reliability Project ("CNJRP"), which I briefly mentioned earlier in my testimony, which, over the next five years, will add a 34.5 kV feed into seventeen substations between 2022 through 2026, focusing on Monmouth County. This will convert 52.4 miles of existing single circuit to double circuit lines, as well as add 2.1 miles of new 34.5 kV underground. The project is expected to address voltage drop and overloading and reduce the likelihood of loss of power or blackouts to the Monmouth County area. In addition to addressing the planning criteria violations, having additional 34.5 kV circuits will provide operational flexibility in and to a load-sensitive part of the Company's service territory. Until this work is substantially complete, the customers in this pocket of Monmouth County are sectionalized during the summer months to prevent cascading outages and a voltage collapse.

Q. Are there any other anticipated developments that may prove to impact the reliability picture discussed above?

A. Yes. During the period 2019-2022, reliability performance in both the Northern and Central regions continued to be measured by SAIFI and CAIDI standards that were last established by the BPU in August 2015. The SAIFI and CAIDI benchmark and minimum standards against which reliability performance has been evaluated since 2016 have been based on the Company's 2010-2014 actual average performance. The pre-determined period of prior actual performance, which has been updated from time-to-time by the Board, primarily, when its reliability regulations have been re-adopted, has been a relatively consistent approach since the Board's reliability regulations were initially promulgated and adopted. It is worth noting that the Board's latest rulemaking, most recently adopted on January 11, 2023, and published in the New Jersey Register (55 N.J.R. 312(b) February 21, 2023) makes adjustments in this approach effective upon publication. In this rulemaking, the Board readopted its regulations at N.J.A.C. 14:5 with some amendments and a new rule. While the amendments to the rules do not impact any of the discussion in my testimony for the years prior to 2023, going forward the changes in the definition of a Major Event and the change in the derivation of the CAIDI and SAIFI benchmarks and minimums from a set five years of past performance to a rolling five years, including the most recent prior year, are expected to impose new and significant challenges to reliability performance measures beginning with 2023. The Company had advocated in its comments for a "transition period" in the implementation of the new rules, an approach which the Board did not include in its revised rules.. The Company remains concerned that manner of

implementation may make it very difficult to compare future year performance to past reported performance based on comparatively different standards.

Q. Does JCP&L have plans to file an IIP?

A. I think it is important to expand upon a reference I made earlier in my testimony with respect to another IIP. With the announcement of its fourth quarter 2022 earnings, on February 14, 2023, FirstEnergy also announced that it plans to file an IIP in New Jersey in the second quarter of 2023 to address circuit resiliency and reliability, additional feeder sectionalizing and increasing system automation and substation upgrades. In this regard, the Company is planning to file a comprehensive plan that will make meaningful enhancements to its distribution as well as its substation infrastructure and will better position the Company to meet and address the various challenges mentioned above and throughout my testimony.

XI. PROPOSED CHANGES TO TARIFF APPENDIX A ("Tariff Appendix A")

Q. What is Tariff Appendix A?

A. Tariff Appendix A is a schedule (in Part II of the JCP&L Tariff for Service) of applicable material unit costs used for purposes of calculating the charges to customers or developers for underground construction of various types.

Q. Have you prepared schedules in connection with this aspect of your testimony?

A. Yes, I have. Schedule DLP-2 provides the proposed form of the revised Tariff Appendix A containing the proposed changes I will discuss herein. Schedule DLP-3 provides the current version of Tariff Appendix A as it currently appears in the Tariff. Schedule DLP-4 shows the man-hour and vehicle rate calculation for 2022. Schedule DLP-5 provides labor

and material overhead rates. Schedule DLP-6 contains a comparison of the current and proposed Tariff Appendix A pricing for an underground installation on a refundable and non-refundable basis.

Q. Please describe the changes that are proposed for Tariff Appendix A of the Tariff.

A. The Company is proposing to update certain charges to reflect current labor costs, material costs, and vehicle rates, with applicable overheads, and other modifications pertaining to Residential Electric Underground Extensions, also referred to as "URDs." In this regard, my testimony supplements and supports the testimony of Yongmei Peng submitted herewith (Exhibit JC-9). The proposed changes result in increased pricing for non-refundable URD installations ranging from 60%-82%, and a 10% increase for refundable installations.

Q. Please explain the basis for the Company's proposed modifications in Schedule DLP-2 related to Tariff Appendix A.

A. In Schedule DLP-2, all the charges are being updated to reflect the Company's current costs. The methodology used to develop the updated charges was the same as the methodology used in the Company's compliance filing pursuant to the Board of Public Utilities Rule Adoption, Docket No. AX12070601, effective December 21, 2015. Charges were developed for four average building lot categories by performing a regression analysis to derive the average charge for a building lot based on 26 sampled projects. Similar to prior filings, charges were also included for primary terminations, including the additional charge for "looping" primary cable in subdivisions with 25 or more single family homes, and the costs associated with installing fault indicators. The Base Charges for Single-Family Non-Refundable charges per lot mainly reflect the differential between

underground and overhead transformers, and the increases are driven by transformer costs and the costs of the secondary enclosure, which together have seen increases of approximately 67% on average over current customer charges for a range of front footage lengths. Wire and cable pricing increases also contributed to the Base Charge increase over current levels. For Base Charges in the case of Single-Family Refundable charges per lot where there is no underground/overhead differential charge, the materials-driven price increase resulted in a 10% increase over current charges.

Q. Please discuss the changes to labor and vehicle rates.

A. The updated charges also reflect the current labor and vehicle rates for JCP&L with applicable overheads. Schedule DLP-4 through Schedule DLP-6, which were prepared by the Engineering group under my supervision, demonstrate a significant increase in labor rates based on market rates over the course of the past three years. Over that time period, the direct average rate for a Line Construction & Maintenance Chief/1st class has increased by approximately 6%. This overall increase reflects annual increases based on the applicable collective bargaining agreement ("CBA"). The CBA provides two 3% increases in calendar year 2023 for the employees represented by Local 1289. The first increase is effective on May 1, 2023, and the second will be effective November 1, 2023. The two increases were based on negotiations which involved a 6-month deferral of wage increases for Local 1289 employees when the contract extension was negotiated. The vehicle rates have also been updated to use 2022 vehicle rate data, which reflects vehicle-related costs that have increased by about 27% since the last revision to Tariff Appendix A in connection with the 2020 Base Rate Filing.

Q. Please discuss the changes to material costs.

A. The updated material costs found in Schedule DLP-4 through Schedule DLP-5 (and mentioned above), are based upon FirstEnergy standards, which are used for construction at JCP&L in New Jersey. The costs in Schedule DLP-4 and Schedule DLP-5 are derived from base units known as Compatible Units ("CUs"). CUs represent discrete job elements of material and/or labor needed for the loading, unloading, transportation and installation of the materials. CUs are combined to form the series of tasks that are required to complete a particular job, such as the installation of an electric service in a URD, which, in turn, allows for the computation of the costs for that particular job.

There are several reasons for the increased material costs. Since 2020, there has been a significant cost increase in base material items. Copper, aluminum, steel, and products derived from oil (wire covering, insulating materials, and other plastic compounds) have all experienced an overall increase since 2020. In addition to the above mentioned, the past two years the world has experienced unprecedented levels of inflation and scarcities in material due to supply chain issues (*see*, for example, Footnote 17 above), and the COVID-19 pandemic. The pandemic has contributed to labor issues including shortages leading to manufacturing and transportation issues resulting in scarcities of materials that JCP&L and industry has not experienced in the past 30 years. As a result, the prices for essential materials that are available have risen in some cases by orders of magnitude.

Q. How did the Company calculate the new charges associated with updating man-hours?

A. The applicable man-hours associated with the various construction units have been updated since the Company's 2020 Base Rate Filing. The process of updating the construction units and their associated labor and material costs was started in November of 2022 using contractual labor rates. Updates were based on current FirstEnergy's Customer Request Work Scheduling System ("CREWS") software, which is discussed further below. Cost estimates are developed based on the design of the project after the appropriate CUs and/or macro units ("MUs") have been assigned to the particular line span and geographic points set forth on the work request ("WR"). I note that the amount of time to construct/install each item did not increase, just the labor costs for such work.

Q. What is meant by the terms: CUs, MUs and points and spans?

A. As mentioned earlier, the costs of a project are derived from base units known as CUs. The CUs represent discrete job elements of material and labor needed for the loading, unloading, transportation, and installation of the material product(s). The CUs are combined to form a series of tasks required to complete a job such as the installation of a transformer and service. In other words, a CU is a standardized assembly that represents the labor tasks, vehicle/equipment hours, and materials required for a construction, maintenance, or operations activity. It may also include facility attributes, accounting information, and unit-of-property information.

An MU, by comparison, is two or more CUs grouped into a logical design or construction. A point or span is the location where materials are installed, removed, or maintained and/or labor is performed as directed by a WR.

In addition, CREWS uses vouchers to identify additional costs associated with a WR, which may be condition sensitive (such as rocky sub-strata that requires special

efforts, or the need in a particular municipality for police traffic control) that cannot be determined based on the CU. The CUs, MUs and vouchers are put together on/in a point and span design in CREWS to develop an estimate of the costs for the project.

Q. What is CREWS?

A. CREWS is the scheduling system that JCP&L uses to develop cost estimates for construction projects. CREWS is a software tool used by designers to layout WRs and adds necessary vehicles, labor, and applicable overheads to provide project cost estimates.

Q. How are estimates of project costs developed in CREWS?

A. Points and spans, as described above, are used in CREWS designs to lay out the construction project. As the project design is developed an estimate of the costs of the project is also developed based on the CUs, MVs and vouchers.

Q. Does the Company propose to eliminate any component of Tariff Appendix A?

A. No.

XII. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

JERSEY CENTRAL POWER & LIGHT
DISTRIBUTION-OPERATIONS & MAINTENANCE EXPENSE
12 MONTHS ENDING JUNE 2023

Line Item	FERC Acct	FERC Acct Desc	AMOUNT	
O&M - Distribution	580	OpSupervision&Engrg	392,311	
	581	LoadDispatching	1,446,055	
	582	StationExp	609,126	
	583	OvhdLineExpenses	1,040,054	
	584	UndergroundLineExp	3,974,417	
	585	StreetLighting	-	
	586	MeterExpenses	3,863,627	
	588	MiscDistributionExp	22,995,565	
	589	Rents	3,791,923	
	590	MaintSupervsn&Engrg	3,029,283	
	591	MaintStructures	50,499	
	592	MaintStationEquip	11,973,912	
	593	MaintOverhdLines	84,228,604	
	594	MaintUndergroundLine	4,572,747	
	595	MaintLineTransformer	151,393	
	596	MtcStreetLght&SigSys	4,146,141	
	597	MaintMeters	4,075,777	
	598	MaintMiscDistribPlt	2,564,666	
			152,906,099	(a)
O&M - Customer Accounts	901	Supervision	42,924	

	902	MeterReadingExpense	15,227,521	
	903	CustRcrd&CollectExp	16,190,497	
	904	UncollectibleAccts	171,298	
	905	MiscCustAcctsExp	1,439,425	
			33,071,665	(b)
O&M - Customer Service	907	Supervision	46,097	
	908	CustAssistExp	2,080,009	
	909	Info&InstrctAdverts	2,645	
	910	MiscCustServ&InfoExp	8,351,286	
			10,480,037	(c)
O&M - Sales Expense	911	Supervision	4	
	913	Advertising Expense	-	
			4	(d)
TOTAL DISTRIBUTION O&M			196,457,805	(e)

(a) Reference schedule CAP-1, column 3, line 8.

(b) Reference schedule CAP-1, column 3, line 9.

(c) Reference schedule CAP-1, column 3, line 10.

(d) Reference schedule CAP-1, column 3, line 11.

(e) Distribution O&M is exclusive of expenses associated with reconcilable riders and A&G expenses.

JCP&L Northern Region 2022

Company-Wide Program	Equipment	Inspection Frequency	2022 Target (Number of Inspections)	Number of Inspections Completed	% of Target Completed
Distribution	Capacitor – Banks[(a)]	Annually	2,167	2,167	100%
	Recloser – Sites[(b)]	Annually	1,404	1,404	100%
Transmission	Aerial[(c)]	Twice / year	2	2	100%
Sub – Transmission	Ground Line Poles[(d)]	Ten-Year Cycle	1,956	1,956	100%
Substation	General	Monthly	1,812	1,812	100%
	Critical (NERC/RFC) Relay Schemes	Five-Year Cycle	52	52	100%
	Infrared Inspections	Annually	151	151	100%
	Battery	Annually	168	168	100%

(a) This table represents the total number of capacitor banks installed. For example, one bank can contain three components.
(b) Multiple reclosers on a single pole are counted as one installation site. Please note that because these numbers reflect annual site inspections, they do not include new additional reclosers installed during the latter half of 2022 for which inspections were not required in 2022.
(c) The entire JCP&L territory is patrolled twice annually.
(d) To account for poles in the current cycle that have been replaced or inspected in an off-cycle year, additional poles are included in the annual schedule to assure adequate inspections for the year, which is why the results may surpass 100%.
(e) Ten-year DC circuit maintenance scheme for 100kV and above BES schemes was added to inspection cycle in 2020.

JCP&L Central Region 2022

Company-Wide Program	Equipment	Inspection Frequency	2022 Target (Number of Inspections)	Number of Inspections Completed	% of Target Completed
Distribution	Capacitor – Banks[(a)]	Annually	2,753	2,753	100%
	Recloser – Sites[(b)]	Annually	991	991	100%
Transmission	Aerial[(c)]	Twice / year	2	2	100%
Sub – Transmission	Ground Line Poles[(d)]	Ten-Year Cycle	2,060	2,060	100%
Substation	General	Monthly	2,088	2,088	100%
	Critical (NERC/RFC) Relay Schemes	Five-Year Cycle	148	142	96%
	Infrared Inspections	Annually	174	174	100%
	Battery	Annually	179	179	100%

(a) This table represents the total number of capacitor banks installed. For example, one bank can contain three components.

(b) Multiple reclosers on a single pole are counted as one installation site. Please note that because these numbers reflect annual site inspections, they do not include new additional reclosers installed during the latter half of 2022 for which inspections were not required in 2022.

(c) The entire JCP&L territory is patrolled twice annually.

(d) To account for poles in the current cycle that have been replaced or inspected in an off-cycle year, additional poles are included in the annual schedule to assure adequate inspections for the year, which is why the results may surpass 100%.

(e) Ten-year DC circuit maintenance scheme for 100kV and above BES schemes was added to inspection cycle in 2020.

JCP&L Company-wide 2022

Company-Wide Program	Equipment	Inspection Frequency	2022 Target (Number of Inspections)	Number of Inspections Completed	% of Target Completed
Distribution	Capacitor – Banks[(a)]	Annually	4,920	4,920	100%
	Recloser – Sites[(b)]	Annually	2,395	2,395	100%
Transmission	Aerial[(c)]	Twice / year	2	2	100%
Sub – Transmission	Ground Line Poles[(d)]	Ten-Year Cycle	4,016	4,016	100%
Substation	General	Monthly	3,900	3,900	100%
	Critical (NERC/RFC) Relay Schemes	Five-Year Cycle	200	194[1]	97%
	Infrared Inspections	Annually	325	325	100%
	Battery	Annually	347	347	100%

(a) This table represents the total number of capacitor banks installed. For example, one bank can contain three components.
(b) Multiple reclosers on a single pole are counted as one installation site. Please note that because these numbers reflect annual site inspections, they do not include new additional reclosers installed during the latter half of 2022 for which inspections were not required in 2022.
(c) The entire JCP&L territory is patrolled twice annually.
(d) To account for poles in the current cycle that have been replaced or inspected in an off-cycle year, additional poles are included in the annual schedule to assure adequate inspections for the year, which is why the results may surpass 100%.
(e) Ten-year DC circuit maintenance scheme for 100kV and above BES schemes was added to inspection cycle in 2020.

[1] Six relay schemes scheduled for inspection were unable to be completed due to a delay in replacing other out of service relays. In order to provide a compliance buffer, relay scheme inspections are scheduled to be completed one year prior to their regulatory (NERC/RFC) deadline. Therefore, these six schemes will be inspected in 2023 and still meet the regulatory (NERC/RFC) deadline.

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. ~~13~~ 14 ELECTRIC - PART II Original Sheet No. 44

Appendix A - Unit Costs of Underground Construction Single Family Developments

Appendix A - Residential Electric Underground Extensions
The Applicant shall pay the Company the amount determined from the following table:

A. Base Charges	Average Front Footage Per Lot			
1. Single Family	<= 125 Ft	126-225 Ft	226-325 Ft	>= 326Ft
Nonrefundable charge per building lot				
• With Applicant providing all trenching and road crossing conduits	$ ~~361~~581.00		$ ~~428~~723.00	$ ~~495~~864.00
$ ~~881~~1,605.00				
Refundable deposit based on equivalent overhead construction	$ ~~828~~914.00		$1,~~656~~828.00	$2,~~484~~742.00
$4,~~140~~570.00				

2. Lots requiring 1Φ primary extension
   Without primary enclosure $~~1,532.00~~1,847.38
   With primary enclosure $~~4,236.44~~5,260.30

3. Duplex-family buildings, mobile homes, multiple occupancy buildings, three-phase high capacity extensions, lots requiring primary extensions thereon, excess transformer capacity above 8.5 KVA, etc. — Charge to be based on differential cost according to unit costs specified in Exhibits I through III

B. Additional Charges

1. Street Lights - SVL
   16 foot fiberglass pole with standard colonial post top luminaire ..... $ ~~365~~492.00
   16 foot fiberglass pole with ornate colonial post top luminaire ..... $1,~~026~~199.00
   30 foot fiberglass pole with cobra head luminaire on 6 foot bracket ..... $1,~~126~~268.00
   12 foot 9 inch ornate fiberglass pole with ornate colonial post top luminaire ..... $2,~~567~~666.00
   12 foot 9 inch ornate fiberglass pole with acorn style post top luminaire ..... $3,~~234~~098.00
   - LED
   16 foot Fiberglass pole with colonial post top luminaire..... $ ~~577~~678.00
   30 foot fiberglass pole with Cobra Head..... $1,~~164~~247.00
   12 foot 9 inch ornate fiberglass pole with acorn style post top luminaire..... $2,~~118~~145.00

2. Multi-Phase Construction $~~1.28~~1.11 per added phase per foot

3. Pavement cutting and restoration, rock removal, blasting, difficult digging, and special backfill — At actual low bid cost with option of Applicant to contract for as limited by NJAC

Note: All charges are subject to taxes as provided in Section 3.14.

Filed pursuant to Order of Board of Public Utilities
Docket Nos. ~~ER20020146 and PUC 04343-2020N~~ dated ~~October 28, 2020~~

Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. ~~13~~ 14 ELECTRIC - PART II **Original Sheet No. 45**

Appendix A - Exhibit I - Unit Costs of Underground Construction Single-Phase 15 kV

Item	Unit	Total Cost
1. Primary cable 1/0 aluminum	per foot	$ ~~3.86~~4.04
2. Secondary cable 3/0 aluminum	per foot	~~2.48~~3.29
350 MCM aluminum	per foot	~~5.02~~5.63
500 MCM aluminum	per foot	~~8.09~~7.17
750 MCM aluminum	per foot	~~11.04~~10.33
3. Service - 200 amp and below	per foot	~~2.48~~3.29
50 feet complete	each	~~614.14~~596.84
4. Primary termination - branch	each	~~1,372.50~~1,642.24
5. Primary junction enclosure - branch	each	~~2,703.80~~3,412.92
6. Secondary enclosure	each	~~646.61~~1,134.53
7. Conduit - 3 inch PVC	per foot	~~3.94~~8.09
Conduit - 4 inch PVC	per foot	~~4.75~~8.53
8. Street light cable - # 12 cu. duplex	per foot	~~2.93~~3.02
9. Transformers - including fiberglass pad		
25 kVa – single-phase	each	~~2,616.27~~3,291.68
50 kVa – single-phase	each	~~2,921.40~~3,688.43
75 kVa – single-phase	each	~~3,305.99~~4,865.17
100 kVa – single-phase	each	~~3,680.90~~4,395.02
167 kVa – single-phase	each	~~4,386.08~~5,552.27
25 kVa – single-phase Dual Voltage	each	~~3,035.23~~3,169.99
50 kVa – single-phase Dual Voltage	each	~~3,299.85~~3,397.93
75 kVa – single-phase Dual Voltage	each	~~4,093.62~~5,437.36
10. Street light poles		
16 foot post top fiberglass pole	each	~~576.58~~678.14
30 foot fiberglass pole	each	~~1,163.74~~1,246.67
12 foot 9 inch ornate fiberglass pole	each	~~2,117.95~~2,144.67
11. Street light luminaire – cobra head SVL	each	~~539.26~~567.88
12. Post top luminaire – SVL		
50, 70, 100 & 150 watt colonial style	each	~~365.76~~360.15
70 & 100 watt ornate colonial style	each	~~1,026.42~~1,067.86
70 & 100 watt ornate acorn style	each	~~1,693.36~~1,499.75
13. Primary splice – # 2 aluminum	each	~~188.84~~223.97

Note: All charges are subject to taxes as provided in Section 3.14.

Issued: ~~October 30, 2020~~ **Effective: ~~December 1, 2020~~**

Filed pursuant to Order of Board of Public Utilities
Docket No~~s~~. ~~ER20020146 and PUC 04343-2020N~~ dated ~~October 28, 2020~~

Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. ~~13~~ 14 ELECTRIC - PART II Original Sheet No. 46

Appendix A - Exhibit II - Unit Costs of Underground Construction Three-Phase 15 kV

	Item	Unit	Total Cost
1.	Primary cable – three-phase main feeder	per foot	$ ~~24.93~~22.24
2.	Secondary cable - 4-wire 350 MCM aluminum	per foot	~~8.60~~9.53
3.	Service cable - 4-wire 350 MCM aluminum	per foot	~~8.92~~10.75
4.	Primary termination - main		
	# 2 aluminum three-phase	each	~~3,365.54~~4,226.12
	1000 MCM aluminum three-phase	each	~~4,961.19~~5,682.50
5.	Primary junction - main	each	~~4,660.04~~5,339.66
6.	Primary switch - main		
	PMH-9	each	~~34,679.04~~31,712.74
	PMH-10	each	~~30,136.80~~27,685.16
	PMH-11	each	~~31,658.44~~28,702.93
	PMH-12	each	~~38,639.32~~34,269.87
7.	Conduit - 5 inch PVC	per foot	~~5.98~~13.75
	- 6 inch PVC	per foot	~~7.40~~12.82
8.	Transformers - including concrete pad		
	75 kVa three-phase	each	~~6,297.08~~7,872.26
	150 kVa three-phase	each	~~6,980.84~~9,297.18
	300 kVa three-phase	each	~~8,835.18~~15,199.18
	500 kVa three-phase	each	~~10,988.05~~14,704.84
9.	Primary splice – 15 kV three-phase cable	each	~~433.75~~432.37

Note: All charges are subject to taxes as provided in Section 3.14.

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300 Madison Avenue, Morristown, NJ 07962-1911

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. ~~13~~ 14 ELECTRIC - PART II **Original Sheet No. 47**

Appendix A - Exhibit III - Unit Costs of Overhead Construction Single and Three-Phase 15 kV

Item	Unit	Total Cost
1. Pole line (including 40 foot poles, anchors & guys)	per foot	$ ~~6.56~~6.94*
2. Primary wire		
Single-phase – branch	per foot	~~2.58~~2.93
Three-phase – main	per foot	~~12.08~~13.92
3. Primary wire - neutral	per foot	~~2.42~~2.74
4. Secondary cable		
Three-wire	per foot	~~5.16~~5.48
Four-wire	per foot	~~8.45~~7.77
5. Service		
Single-phase	each	~~244.60~~264.70
Single–phase - 200 amp and below	per foot	~~2.49~~2.72
Three-phase – up to 200 amp	per foot	~~4.02~~3.93
Three-phase – over 200 amp	per foot	~~6.67~~5.62
6. Transformers		
25 kVa – single-phase	each	~~1,453.17~~1,776.44
50 kVa – single-phase	each	~~1,763.05~~2,269.32
75 kVa – single-phase	each	~~2,273.13~~2,860.31
100 kVa – single-phase	each	~~2,635.99~~3,312.11
167 kVa – single-phase	each	~~3,073.14~~3,327.65
3- 25 kVa – three-phase	each	~~3,818.97~~4,943.29
3- 50 kVa – three-phase	each	~~4,748.61~~6,391.93
3- 75 kVa – three-phase	each	~~6,404.91~~8,421.13
3-100 kVa – three-phase	each	~~7,481.49~~9,776.53
3-167 kVa – three-phase	each	~~8,792.94~~9,823.15
7. Street light luminaire – cobra head SVL	each	~~577.38~~546.61

Pole line cost to be used = $~~6.56~~6.94 / 2 = $~~3.28~~3.47

Note: All charges are subject to taxes as provided in Section 3.14.

Issued: ~~October 30, 2020~~ **Effective: ~~December 1, 2020~~**

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300 Madison Avenue, Morristown, NJ 07962-1911

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. ~~13~~ 14 ELECTRIC - PART II Original Sheet No. 48

Appendix A - Exhibit III - Unit Costs of Overhead Construction Single and Three-Phase 15 kV

Item	Unit	Total Cost
8. Street light luminaire – LED – Contributions		
Monthly Contribution Fixture charge of $2.65		
30 W Cobra Head	each	$ 358.38
50 W Cobra Head	each	354.88
90 W Cobra Head	each	403.55
130 W Cobra Head	each	492.97
260 W Cobra Head	each	694.22
50 W Acorn	each	1,295.80
90 W Acorn	each	1,243.30
50 W Colonial	each	619.38
90 W Colonial	each	793.88
Monthly Contribution Fixture charge of $4.24		
30 W Cobra Head	each	209.20
50 W Cobra Head	each	205.70
90 W Cobra Head	each	254.37
130 W Cobra Head	each	343.79
260 W Cobra Head	each	545.04
50 W Acorn	each	1,146.62
90 W Acorn	each	1,094.12
50 W Colonial	each	470.20
90 W Colonial	each	644.70

Note: All charges are subject to taxes as provided in Section 3.14.

Issued: ~~October 30, 2020~~ **Effective:** ~~December 1, 2020~~

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JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 13 ELECTRIC - PART II Original Sheet No. 44

Appendix A - Unit Costs of Underground Construction
Single Family Developments

Appendix A - Residential Electric Underground Extensions
The Applicant shall pay the Company the amount determined from the following table:

A. Base Charges	Average Front Footage Per Lot			
1. Single Family	<= 125 Ft	126-225 Ft	226-325 Ft	>= 326Ft
Nonrefundable charge per building lot				
• With Applicant providing all trenching and road crossing conduits	$ 361.00	$ 428.00	$ 495.00	$ 881.00
Refundable deposit based on equivalent overhead construction	$ 828.00	$1,656.00	$2,484.00	$4,140.00

2. Lots requiring 1Φ primary extension
   Without primary enclosure $1,532.00
   With primary enclosure $4,236.44

3. Duplex-family buildings, mobile homes, multiple occupancy buildings, three-phase high capacity extensions, lots requiring primary extensions thereon, excess transformer capacity above 8.5 KVA, etc. — Charge to be based on differential cost according to unit costs specified in Exhibits I through III

B. Additional Charges

1. Street Lights - SVL
   16 foot fiberglass pole with standard colonial post top luminaire ..... $ 365.00
   16 foot fiberglass pole with ornate colonial post top luminaire $1,026.00
   30 foot fiberglass pole with cobra head luminaire on 6 foot bracket $1,126.00
   12 foot 9 inch ornate fiberglass pole with ornate colonial post top luminaire $2,567.00
   12 foot 9 inch ornate fiberglass pole with acorn style post top luminaire - LED $3,234.00
   16 foot Fiberglass pole with colonial post top luminaire……$ 577.00
   30 foot fiberglass pole with Cobra Head……$1,164.00
   12 foot 9 inch ornate fiberglass pole with acorn style post top luminaire……$2,118.00

2. Multi-Phase Construction $1.28 per added phase per foot

3. Pavement cutting and restoration, rock removal, blasting, difficult digging, and special backfill — At actual low bid cost with option of Applicant to contract for as limited by NJAC

Note: All charges are subject to taxes as provided in Section 3.14.

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 13 ELECTRIC - PART II Original Sheet No. 45

Appendix A - Exhibit I - Unit Costs of Underground Construction Single-Phase 15 kV

Item	Unit	Total Cost
1. Primary cable 1/0 aluminum	per foot	$ 3.86
2. Secondary cable 3/0 aluminum	per foot	2.48
350 MCM aluminum	per foot	5.02
500 MCM aluminum	per foot	8.09
750 MCM aluminum	per foot	11.04
3. Service - 200 amp and below	per foot	2.48
50 feet complete	each	614.14
4. Primary termination - branch	each	1,372.50
5. Primary junction enclosure - branch	each	2,703.80
6. Secondary enclosure	each	646.61
7. Conduit - 3 inch PVC	per foot	3.94
Conduit - 4 inch PVC	per foot	4.75
8. Street light cable - # 12 cu. duplex	per foot	2.93
9. Transformers - including fiberglass pad		
25 kVa – single-phase	each	2,616.27
50 kVa – single-phase	each	2,921.40
75 kVa – single-phase	each	3,305.99
100 kVa – single-phase	each	3,680.90
167 kVa – single-phase	each	4,386.08
25 kVa – single-phase Dual Voltage	each	3,035.23
50 kVa – single-phase Dual Voltage	each	3,299.85
75 kVa – single-phase Dual Voltage	each	4,093.62
10. Street light poles		
16 foot post top fiberglass pole	each	576.58
30 foot fiberglass pole	each	1,163.74
12 foot 9 inch ornate fiberglass pole	each	2,117.95
11. Street light luminaire – cobra head SVL	each	539.26
12. Post top luminaire – SVL		
50, 70, 100 & 150 watt colonial style	each	365.76
70 & 100 watt ornate colonial style	each	1,026.42
70 & 100 watt ornate acorn style	each	1,693.36
13. Primary splice – # 2 aluminum	each	188.84

Note: All charges are subject to taxes as provided in Section 3.14.

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 13 ELECTRIC - PART II Original Sheet No. 46

Appendix A - Exhibit II - Unit Costs of Underground Construction Three-Phase 15 kV

	Item	Unit	Total Cost
1.	Primary cable – three-phase main feeder	per foot	$ 24.93
2.	Secondary cable - 4-wire 350 MCM aluminum	per foot	8.60
3.	Service cable - 4-wire 350 MCM aluminum	per foot	8.92
4.	Primary termination - main		
	# 2 aluminum three-phase	each	3,365.54
	1000 MCM aluminum three-phase	each	4,961.19
5.	Primary junction - main	each	4,660.04
6.	Primary switch - main		
	PMH-9	each	34,679.04
	PMH-10	each	30,136.80
	PMH-11	each	31,658.44
	PMH-12	each	38,639.32
7.	Conduit - 5 inch PVC	per foot	5.98
	- 6 inch PVC	per foot	7.40
8.	Transformers - including concrete pad		
	75 kVa three-phase	each	6,297.08
	150 kVa three-phase	each	6,980.84
	300 kVa three-phase	each	8,835.18
	500 kVa three-phase	each	10,988.05
9.	Primary splice – 15 kV three-phase cable	each	433.75

Note: All charges are subject to taxes as provided in Section 3.14.

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 13 ELECTRIC - PART II Original Sheet No. 47

Appendix A - Exhibit III - Unit Costs of Overhead Construction Single and Three-Phase 15 kV

	Item	Unit	Total Cost
1.	Pole line (including 40 foot poles, anchors & guys)	per foot	$ 6.56*
2.	Primary wire		
	Single-phase – branch	per foot	2.58
	Three-phase – main	per foot	12.08
3.	Primary wire - neutral	per foot	2.42
4.	Secondary cable		
	Three-wire	per foot	5.16
	Four-wire	per foot	8.45
5.	Service		
	Single-phase	each	244.60
	Single–phase - 200 amp and below	per foot	2.49
	Three-phase – up to 200 amp	per foot	4.02
	Three-phase – over 200 amp	per foot	6.67
6.	Transformers		
	25 kVa – single-phase	each	1,453.17
	50 kVa – single-phase	each	1,763.05
	75 kVa – single-phase	each	2,273.13
	100 kVa – single-phase	each	2,635.99
	167 kVa – single-phase	each	3,073.14
	3- 25 kVa – three-phase	each	3,818.97
	3- 50 kVa – three-phase	each	4,748.61
	3- 75 kVa – three-phase	each	6,404.91
	3-100 kVa – three-phase	each	7,481.49
	3-167 kVa – three-phase	each	8,792.94
7.	Street light luminaire – cobra head SVL	each	577.38

Pole line cost to be used = $6.56 / 2 = $3.28

Note: All charges are subject to taxes as provided in Section 3.14.

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 13 ELECTRIC - PART II Original Sheet No. 48

Appendix A - Exhibit III - Unit Costs of Overhead Construction Single and Three-Phase 15 kV

Item	Unit	Total Cost
8. Street light luminaire – LED – Contributions		
Monthly Contribution Fixture charge of $2.65		
30 W Cobra Head	each	$ 358.38
50 W Cobra Head	each	354.88
90 W Cobra Head	each	403.55
130 W Cobra Head	each	492.97
260 W Cobra Head	each	694.22
50 W Acorn	each	1,295.80
90 W Acorn	each	1,243.30
50 W Colonial	each	619.38
90 W Colonial	each	793.88
Monthly Contribution Fixture charge of $4.24		
30 W Cobra Head	each	209.20
50 W Cobra Head	each	205.70
90 W Cobra Head	each	254.37
130 W Cobra Head	each	343.79
260 W Cobra Head	each	545.04
50 W Acorn	each	1,146.62
90 W Acorn	each	1,094.12
50 W Colonial	each	470.20
90 W Colonial	each	644.70

Note: All charges are subject to taxes as provided in Section 3.14.

Jersey Central Power & Light
A FirstEnergy Company

EXHIBIT A

STANDARD MAN-HOUR RATE CALCULATION

2022 NEW JERSEY LINEMEN

Job # 221	Line Construction & Maintenance – Chief "B"	$ 56.01/ hr
Job # 226	Line Construction & Maintenance – 1st Class	$ 53.69/ hr
		$109.70/ hr

Standard Rate per Man-Hour = $109.70 / 2 = ... $ 54.85/ man-hr

Line Crew Supervisor ..... $ 8.41/ man-hr

Total Rate per Man-hour ..... $ 63.26/ man-hr

Total Direct Labor Rate per Man-Hour..... $ 63.26/man-hr

Line Construction & Maintenance Rates are based upon actual averages for the current work force in New Jersey. These rates are slightly higher than the labor contract rates because of some personalized rates.

Line Crew Supervisor Rate is derived from JCP&L/FE's "market rate" base wage for this job

classification. The "market rate" for this job is $ 140,000/year; based on 2080 hours available for work per year, this rate equals $67.31 per hour. A Line Crew Supervisor is responsible for four two-man crews, so one eighth of this rate, which is $8.41, is applied per man-hour.

VEHICLE RATES

Line Truck (WKTRK) Includes Class 4, Class 5, and Dump Truck..... $ 34.88/hour

WKTRK Rate per Man-Hour (2 man crew) = 34.88 ÷ 2..... $ 17.44/man-hr

Jersey Central Power & Light
A FirstEnergy Company

EXHIBIT B

LABOR OVERHEAD RATE- 2022 NEW JERSEY LINEMEN

LC&M Chief "B"		LC&M
BASE HOURLY WAGES	**$ 56.01**	**$ 53.69**

ACTIVITY LABOR RATES

PENSION SERVICES	22.44%
OPEB SERVICES	2.08%

TOTAL ACTIVITY LABOR RATE 24.52%

BENEFITS & TAXES

FRINGE BENEFITS	24.96%
PAYROLL TAXES	8.24%

INCENTIVE COMPENSATION 6.00%

TOTAL BENEFITS & TAXES 39.20%

TOTAL LABOR OVERHEAD RATE.....63.72%

MATERIAL OVERHEAD RATE

STORE HANDLING.....39.80%

EXHIBIT C

Schedule DLP-6

COMPARISON OF UPDATED APPENDIX A TARIFF CHARGES

Type Of Installation	Charges per Building Lot – Average Front Footage per Lot			
	< = 125 Ft	126 – 225 Ft	226 – 325 Ft	> = 326 Ft
Installation with Customer Providing All Trenching				
Non-Refundable Charges per Building Lot				
Current Charges	$361	$428	$495	$881
Revised Charges	$581	$723	$864	$1,605

Refundable Charges per Building Lot				
Current Charges	$828	$1,656	$2,484	$4,140
Revised Charges	$914	$1,828	$2,742	$4,570

EXHIBIT JC-6

BEFORE THE

NEW JERSEY BOARD OF PUBLIC UTILITIES

In the Matter of the Verified Petition of Jersey Central Power & Light Company for Review and Approval of Increases in and Other Adjustments to Its Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith

Direct Testimony

of

Bill Wang

Re: Capital Structure and Cost of Capital

I. INTRODUCTION AND BACKGROUND

Q. Please state your name and business address.

A. My name is Bill Wang. My business address is 76 South Main Street, Akron, OH 44308.

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

A. I am employed by FirstEnergy Service Company ("FESC"). My title is Assistant Treasurer. I am also the Treasurer for Jersey Central Power & Light Company ("JCP&L" or the "Company").

Q. **What are your current responsibilities?**

A. I am responsible for managing the FirstEnergy Corp. ("FirstEnergy") family's pension and other post-retirement plan investments and supporting finance-related activities including budgeting, forecasting, and financial planning. I have served as the Treasurer of JCP&L since 2012. As Treasurer of JCP&L, I am responsible for treasury activities including capital markets, liquidity management, derivatives, investment management, and debt compliance.

Q. **Have you previously testified in proceedings before the New Jersey Board of Public Utilities ("Board" or "BPU")?**

A. I have not filed written testimony with the BPU. However, I have appeared before the BPU at a public hearing in BPU Docket No. EF20110702.

Q. Please describe your educational background and professional experience.

A. I joined Corning Incorporated ("Corning") as a Senior Financial Analyst in May 2001 after I received my MBA from the Business School of University of Maryland in College Park. At Corning, I was part of the Treasury team, and participated in its capital structure management including various capital market transactions and banking relationship management. In July 2005, I joined Allegheny Energy, Inc. which was purchased by FirstEnergy in 2011. I was elected to Assistant Treasurer in 2016. Prior to that, I served in various Treasury positions such as Director, Treasury Integration and Director, Investment Management, managing the company's capital structure, asset investments related to the company's pension, savings and other post-retirement plans.

Q. What is the purpose of your direct testimony?

A. My testimony will describe and explain: (1) JCP&L's capital structure; (2) JCP&L's embedded cost of long-term debt; (3) JCP&L's overall weighted average cost of capital; and (4) the impact of timely recovery on JCP&L's credit metrics.

Q. Please identify and describe the schedules to your testimony.

A. I have attached to my testimony five Schedules, identified as follows:

Schedule BW-1 Capital Structures of FirstEnergy Corp. and JCP&L
Schedule BW-2 Recommended Capital Structure for JCP&L
Schedule BW-3 Embedded Cost of JCP&L's Long-Term Debt
Schedule BW-4 JCP&L's Weighted Average Cost of Capital
Schedule BW-5 Standard & Poor's October 19, 2021 Research Update

II. CAPITAL STRUCTURE

Q. Why have you presented the capital structures both for JCP&L and FirstEnergy?

A. I have included the capital structures for both FirstEnergy and JCP&L in Schedule BW-1 because it is a requirement contained in the Stipulation entered into by several parties including JCP&L, the Division of the Ratepayer Advocate (now the Division of Rate Counsel) and Board Staff in connection with the merger between FirstEnergy and JCP&L's former parent company, GPU, Inc., which was approved in the Board's Order dated October 9, 2001 in Docket No. EM00110870. The relevant provision of the Stipulation states as follows:

> JCP&L further agrees to file, in all future base rate cases, its case using two alternative capital structures. One of the alternatives will be a consolidated capital structure based on the capital structure that is maintained by FirstEnergy (the holding company). The second alternative will be a stand-alone JCP&L capital structure. The parties to future base rate cases will be free to argue for the benefits of using either capital structure for ratemaking purposes or another alternative.

I recommend, however, that JCP&L's capital structure be used in this case, rather than that of FirstEnergy.

Q. Why should JCP&L's capital structure be used in this case?

A. The purpose of this rate proceeding is to determine the appropriate rates for the regulated entity, JCP&L. Those rates should be based on JCP&L's rate base, revenues, and expenses, and should provide a fair rate of return that reflects the risk-return profile of JCP&L, and not FirstEnergy. FirstEnergy is a non-regulated entity, and its assets and liabilities, revenues and expenses are not being evaluated in this proceeding, nor is there any assessment in this proceeding of FirstEnergy's unique risk-return profile, which is separate and distinct from that of JCP&L. In addition, it is my understanding that the Board's long-standing practice is to use the utility's own capital structure for ratemaking purposes.

Q. Please describe what the projected actual capital structure of JCP&L will be on September 30, 2023.

A. JCP&L's projected capital structure of 34.2% debt and 65.8% equity on September 30, 2023 is shown in Schedule BW-1. This calculation includes JCP&L's goodwill balance. Total debt for purposes of the capital structure to be utilized in this proceeding does not include the balances of short-term debt. Short-term borrowings are sources of liquidity and are not utilized to finance long-lived assets, such as those included in JCP&L's rate base. Furthermore, it is the Board's practice to exclude short-term debt from a utility's capital structure in the context of base rate cases.

Q. Why are you proposing a capital structure at September 30, 2023, rather than at the end of the test year?

A. The Board's long-standing practice regarding post-test year adjustments to capital structure is based on its decision in *In re Elizabethtown Water Company*, Dkt. No WR8504330 (Order dated May 23, 1985), at 2 ("*Elizabethtown Water*"). According to the Board's *Elizabethtown Water* precedent, where rate case filings include some historical and some forecast data, utilities are generally permitted to include in base rate requests known and measurable adjustments to the capital structure three months beyond the test year for rate base. In the application of *Elizabethtown Water* in this case, the capital structure at September 30, 2023 only differs from the end of the test year, at June 30, 2023, by the forecasted retained earnings.

Q. Are you proposing an adjusted JCP&L capital structure?

A. Yes. JCP&L recognizes that its projected capital structure at September 30, 2023 has an equity percentage that is outside the range typically approved for ratemaking purposes in New Jersey. JCP&L is proposing to lower its equity percentage by subtracting out its goodwill balance. This adjustment was utilized in the capital structure calculation in JCP&L's 2020 base rate case.[1] Therefore, JCP&L is proposing an adjusted hypothetical capital structure of 48.1% debt and 51.9% equity, as reflected in Schedule BW-2, instead of its actual capital structure.

Q. Are there any other comments you would like to make with regard to capital structure?

A. Yes. I believe that it is vital that JCP&L maintains access to the capital markets on favorable terms. Setting a rate of return which is based on a capital structure that warrants solid investment grade ratings is necessary because it allows JCP&L to access the capital markets on favorable terms, to maintain its financial integrity and financial flexibility, and fund investments in its distribution system that are necessary for safe, proper and adequate service. Customers, in turn, benefit from JCP&L incurring lower debt costs as a result.

[1] The Stipulation of Settlement, dated October 15, 2020, was approved by the New Jersey Board of Public Utilities on October 28, 2020 (BPU Docket No. ER20020146, OAL Docket No. PUC 04343-2020N). Paragraph 10: *The Parties further agree that the revenue increase is based on a post-tax rate of return of 7.40%, with a capital structure consisting of 51.44% common equity with a cost rate of 9.60%, and 48.56% long term debt with a cost rate of 5.083%.*

III. COST OF CAPITAL

Q. Please describe the calculation of JCP&L's overall embedded cost of long-term debt.

A. Schedule BW-3 contains the embedded cost schedules for JCP&L's long-term debt. The long-term debt schedule details each series of debt, the date of issuance, maturity, original amount issued and current amount outstanding. The issuance expenses (column 4) represent legal, underwriting, and other miscellaneous costs associated with the issuance. The original amount issued plus any premium or minus any discount, reduced by any issuance expenses, results in the net proceeds. The embedded cost rate (column 7) is calculated by taking the net proceeds at the time of issuance and calculating the internal rate of return based on the coupon and the years to maturity. After the embedded rate is calculated for each individual series, the rates are weighted by taking the embedded rate multiplied by the adjusted amount outstanding (amount outstanding multiplied by the net proceeds ratio) and divided by the total adjusted amount of long-term debt outstanding. The embedded cost (column 8) is the embedded rate multiplied by the adjusted amount outstanding, which is calculated by multiplying the net proceeds ratio by the current amount outstanding. As shown on Schedule BW-3, these calculations produce an overall embedded long-term debt cost rate of 4.572%.

Q. How does the current long-term debt cost rate of 4.572% compare to the long-term debt cost rate approved in the Company's last rate case?

A. The long-term debt cost rate approved by the Board in JCP&L's last base rate case and currently reflected in base rates is 5.083%. The effect of the $500 million

issuance in June 2021 resulted in a decrease of 51.1 basis points in the long-term debt cost rate.

Q. Please describe the calculation of the weighted average cost of capital.

A. I have calculated JCP&L's weighted average cost of capital to be 7.60%. The calculation of the weighted average cost of capital is shown on Schedule BW-4. The calculation weights the cost of common equity and embedded cost of long-term debt by the adjusted ratemaking capitalization ratios. The cost of common equity is supported by the testimony of Dylan D'Ascendis in this filing (Exhibit JC-7). The adjusted ratemaking capitalization ratios are sourced from Schedule BW-2 and have been described earlier in my testimony. The embedded cost of long-term debt is sourced from Schedule BW-3 and has been described earlier in my testimony.

IV. NEAR-TERM IMPACTS OF CASH REQUIREMENTS ON JCP&L CREDIT RATINGS

Q. Why is it important for an electric utility to have strong credit ratings?

A. The electric utility industry is engaged in the development of electric infrastructure, which makes it a highly capital-intensive industry. To fund investments in electric infrastructure, electric utilities must be able to effectively and efficiently access the capital markets to ensure adequate liquidity to support construction, maintenance and operation of the transmission and distribution systems. A utility's credit ratings impact the cost to the utility to raise capital. As the cost of capital is a component of the utility's cost of service and is recovered through electric service charges, the utility's credit ratings ultimately affect costs paid by customers for electric service.

Q. What are the current credit ratings for FirstEnergy and JCP&L from the three nationally recognized statistical ratings organizations ("NRSRO")?

A. The current credit ratings from Standard & Poor's ("S&P"), Moody's Investor Service ("Moody's") and Fitch Ratings ("Fitch"), as of March 15, 2023, are listed in the table below.

	Issuer/Corporate Family			Senior Unsecured Debt		
	S&P	Moody's	Fitch	S&P	Moody's	Fitch
FirstEnergy	BBB-	Ba1	BBB-	BB+	Ba1	BBB-
JCP&L	BBB	A3	BBB	BBB	A3	BBB+

Q. Do credit ratings of the parent company such as FirstEnergy affect the ratings of the subsidiaries in a corporate group or holding company?

A. Yes. Rating agencies consider the linkages between parent companies and subsidiaries when establishing credit ratings. The manner and extent to which these linkages are considered for ratings purposes are different for each rating agency, based on each agency's respective ratings methodology. As a result, the credit profile of the parent and subsidiaries within the corporate group or holding company may affect the credit ratings of a subsidiary, based on, and including but not limited to, the business risk and financial risk of the business activities of the parent and other subsidiaries, and the extent to which the parent and subsidiaries are financially interdependent.

However, corporate groups and holding companies can take measures to insulate a subsidiary from other subsidiaries and the parent for the purpose of protecting a subsidiary from the consequences of financial events (e.g., bankruptcy)

at the parent or other subsidiaries within the corporate group or holding company. Such measures or practices are referred to as "ring-fencing." Effective ring-fencing may enable higher credit ratings for a subsidiary within a comparably weaker corporate group or holding company. This is the case for JCP&L, as ring-fencing measures in place enable JCP&L to have higher credit ratings than its parent from all three major ratings agencies. In fact, JCP&L's Issuer and Senior Unsecured credit ratings are four notches higher than FirstEnergy at Moody's, and JCP&L's Senior Unsecured Debt is rated two notches higher by S&P and Fitch.

Q. What are some of the actions taken following the downgrades of FirstEnergy and its subsidiaries by S&P and Fitch in the fall of 2020 to support improvement of those ratings?

A. Regarding JCP&L, in October 2021, FirstEnergy established six individual revolving credit facilities, including one which is JCP&L-specific. FirstEnergy previously had in place two separate revolving credit facilities providing for aggregate commitments of $3.5 billion, a $2.5 billion commitment for FirstEnergy and its regulated subsidiaries (including JCP&L) and a $1 billion commitment for FirstEnergy's transmission subsidiaries. Each revolving credit facility had individual sub-limits for each participant. JCP&L now has its own revolving credit facility, with a commitment of $500 million that is equal to its Federal Energy Regulatory Commission authorized short-term borrowing authority. The purpose of this step was to provide for further ring-fencing for JCP&L by diminishing the financial linkages between JCP&L, its parent, and FirstEnergy's other subsidiaries.

Meanwhile, FirstEnergy made significant progress in 2022 to improve its balance sheet and strengthen its credit profile. Using the proceeds from several equity transactions, approximately $2.6 billion of FirstEnergy holding company debt was eliminated. This includes the early retirement of an $850 million note in January, a $500 million note in June, and the repurchase of approximately $1.25 billion in high-coupon notes through a combination of tender offers and open-market repurchases. On a generally accepted accounting principles or "GAAP" basis, these accomplishments surpass the original plan for holding company debt reduction and brings FirstEnergy debt as percentage of total debt to 26% at the end of 2022 as compared to 33% at the end of 2021. Based on Moody's methodology, FirstEnergy had Cash Flow From Operations Before Changes To Working Capital to Debt ("CFO pre-WC to Debt Ratio") of just under 11% in 2022 and expects to be above Moody's CFO pre-WC to Debt Ratio upgrade threshold (at or above 11%) in 2023.

On February 2, 2023, FirstEnergy agreed to sell an incremental 30% equity interest in FirstEnergy Transmission, LLC for a purchase price of $3.5 billion. The transaction is expected to close in the first quarter of 2024, subject to regulatory approvals. FirstEnergy intends to deploy the proceeds with a priority on further strengthening the balance sheet while also providing capital for higher levels of future regulated investments.

Q. With respect to JCP&L, was the creation of a standalone credit facility effective in diminishing the financial linkage with FirstEnergy?

A. Yes. The day following FirstEnergy's completion of establishing six individual credit facilities, S&P raised the Issuer Credit Rating to BB+ from BB and the Senior Unsecured Credit Ratings from BB+ to BBB- for JCP&L and others.[2] Relative to JCP&L and other affiliates, on page 2 of its October 19, 2021 Research Update, as rationale for its ratings upgrade, S&P stated: "The new credit facility agreements supplement the existing separateness and insulating measures already in place. As such, we assess the cumulative ring-fencing measures as sufficient to rate the utilities one notch above the GCP [Group Credit Profile]" (See Schedule BW-5).

Q. What financial metrics do the NRSROs review to assign credit ratings?

A. Each NRSRO has its own ratings methodology that considers several financial metrics in determining an entity's credit rating. The financial metrics reviewed may include: EBIT (Earnings Before Income Taxes) Interest Coverage; Return on Capital; and some measure of cash flow from operations as a ratio to debt, such as CFO pre-WC to Debt Ratio. The cash flow from operations as a ratio of debt metric is an important metric commonly relied upon as a basis to establish credit ratings. In addition to these key financial metrics, there are other qualitative factors or ratings qualifiers that are then applied to determine the credit rating. These qualifiers may include regulatory environment, operating performance and efficiency, corporate governance, and industry and/or company specific risks.

Q. Please explain the CFO pre-WC to Debt Ratio referenced above.

[2] https://disclosure.spglobal.com/ratings/en/regulatory/article/-/view/type/HTML/id/2740605

A. CFO pre-WC to Debt Ratio is a metric used by Moody's. Generally, the CFO pre-WC to Debt ratio is a measure of cash flow from operations as compared to the total short-term and long-term debt outstanding, expressed as a percentage. This methodology calls for certain adjustments to both cash flows from operations and debt in the calculation of this ratio. For purposes of my testimony, I will use the CFO pre-WC to Debt Ratio to discuss the impacts of large expenditures and the associated rate recovery on JCP&L's CFO pre-WC to Debt Ratio.

Q. Given that JCP&L's recent and forecasted performance with respect to the CFO pre-WC to Debt Ratio is below the threshold of 19% for an A3 rating, is there potential for any ratings changes at JCP&L?

A. Not without improvements to cost recovery. Moody's has recently cited storm costs in 2020 and regulatory lag associated with cost recovery in 2020 and 2021 as pressuring JCP&L's credit metrics. Going forward, the funding and recovery of JCP&L's large, deferred storm cost balance, advanced metering infrastructure deployment (AMI, i.e., smart meters) and electric vehicle (EV) programs through base rate deferral mechanisms also pressure JCP&L's CFO pre-WC to Debt Ratio. Based on the Company's financial forecast for 2023 – 2025, JCP&L likely will not be able to attain and maintain a CFO pre-WC to Debt Ratio above the 19% necessary to support Moody's current rating of A3. In fact, without improvements to cash flows to support JCP&L's credit metrics, a negative credit action by Moody's may occur.

Q. How does the $310 million[3] deferred storm balance negatively impact credit ratings?

A. The deferred storm balance impacts JCP&L's credit metrics in two ways. First, a major storm is an anomalous event and the cost of extensive restoration efforts often outstrip available "cash on hand." In such circumstances, JCP&L borrows on a short-term basis, generally first from the FirstEnergy Regulated Money Pool, to fund the cash cost of storm restoration, including both capital and operation and maintenance ("O&M") costs. The increased debt to fund storm restoration increases the denominator in the calculation of the CFO pre-WC to Debt Ratio. A higher denominator lowers the resulting ratio. Second, JCP&L receives no current recovery of carrying costs on its deferred storm balance, which lowers the numerator. A lower numerator in the calculation of the CFO pre-WC to Debt Ratio metric lowers the resulting ratio. Including and recovering a carrying charge on the deferred storm balance and/or simply increasing recovery of the deferred storm balance in base rates would increase the resulting CFO pre-WC to Debt Ratio and be more credit supportive for JCP&L.

Q. To the extent JCP&L finances storm restoration costs with short-term debt, why would it impact the CFO pre-WC to Debt Ratio?

A. For regulatory purposes, "debt" usually refers to borrowing to provide for long-term capitalization of rate base. For purposes of establishing credit ratings, the rating agency methodologies include both short-term and long-term debt as "debt", and for Moody's, the CFO pre-WC to Debt Ratio. Therefore, deferred storm costs,

[3] As of December 31, 2022.

to the extent they are funded by short-term and/or long-term debt, adversely impact the CFO pre-WC to Debt Ratio.

Q. What determines how JCP&L finances its deferred storm balance?

A. JCP&L does not issue debt or assign tranches of debt specifically to finance storm costs. JCP&L uses a combination of short-term and long-term debt to meet the cash requirements for operations, capital investments and general business purposes of JCP&L, including funding storm restoration. As storm events occur, JCP&L generally first uses cash on hand to fund the restoration efforts. To the extent that additional funding is required, JCP&L relies on short-term debt, generally first sourced from the FirstEnergy Regulated Money Pool, which is JCP&L's least expensive source of liquidity. As discussed, JCP&L has its own $500 million revolving credit facility. JCP&L's short-term debt authority is currently $500 million total, so borrowing from the money pool and the revolving credit facility, in combination, cannot exceed $500 million. Should JCP&L approach its short-term debt limit, JCP&L would petition the BPU for authority to issue long-term debt and convert such outstanding short-term debt to long-term debt, thus restoring its short-term borrowing capacity. Therefore, depending on the cost of an event, the period of time that JCP&L carries the deferred storm costs on its books and the timing of its long-term debt issuance, some or all of the costs of major storm events may be financed with long-term debt.

Q. How do the AMI and EV Program investments and the associated rate recovery affect JCP&L's credit ratings?

A. When JCP&L can finance its capital investments with cash generated from operations, it can operate with no additional debt requirements. However, to the extent that there are cash requirements that cause JCP&L to be cash flow negative, JCP&L will need to raise capital. Therefore, to the extent that debt financing is used, there will be impacts on the CFO pre-WC to Debt Ratio, depending on the magnitude of these incremental cash requirements and the timeliness of the rate recovery associated with these incremental cash expenditures.

During the 2023 - 2025 forecast horizon, JCP&L has significant cash requirements to fund its AMI and EV Programs. JCP&L has also announced its plans to file an infrastructure investment program ("IIP") later this year. Recovery of AMI and EV Program costs is through deferral mechanisms that delay recovery to future base rate cases. As these costs are in addition to JCP&L's base capital and O&M budgets, JCP&L will need to raise capital to fund these programs as well. Higher levels of investment require increased borrowings at JCP&L and with substantial recovery being deferred until a future base rate case, the CFO pre-WC to Debt Ratio will be negatively impacted.

With respect to AMI deployment, the cash requirement includes $390 million for plant in service, $73.3 million for O&M, and $30.8 million in Cost of Removal, for a total of $494.1 million. The Deployment Phase of JCP&L's AMI Plan is to occur over a three-year period from 2023 - 2025. As a result, there are

significant cash requirements at JCP&L from 2023 - 2025, which pressure JCP&L's CFO pre-WC to Debt Ratio from this effort alone.

With respect to its Light Duty EV Program, JCP&L's cash requirements from July 2022 through June 2026 are budgeted to be $39.9 million. The cash requirements and the impacts to CFO pre-WC to Debt Ratio as a result of the Light Duty EV Program itself are not significant. However, cash requirements for this program are additive to cash requirements during a time period where there are very significant cash requirements to finance deferred storm costs and other required capital investments, such as AMI deployment, a second IIP, and the medium and heavy-duty EV program anticipated to be undertaken by JCP&L.

Q. Does JCP&L's request in the instant filing include recovery of the AMI and Light Duty EV Program costs?

A. Yes, it does. JCP&L is requesting recovery of its AMI Investment and O&M deferred regulatory assets based on a 10-year amortization, which results in a $1.8 million test year adjustment (See testimony of Carol Pittavino, Schedule CAP-2, Adjustment 11). Also, JCP&L is requesting recovery of the EV deferred regulatory assets based on a five-year amortization, which results in a $445,552 test year adjustment (See testimony of Carol Pittavino, Schedule CAP-2, Adjustment 9).

Q. What is JCP&L requesting of the BPU to further support JCP&L's current credit ratings?

A. Setting aside the Company's general rate increase request, JCP&L is asking that the BPU recognize in its deliberations that the lag in recovery that is present for

capital intensive, and in some cases accelerated, investments such as those described above are not only impactful to JCP&L's cash flows, but also drive negative and very real downstream impacts to its credit metrics and, ultimately, debt costs paid by customers. In the instant case, granting the Company's requests for recovery of the AMI and Light Duty EV Program amortizations, as well as the requested increase in storm cost recovery, as proposed, would be a credit supportive step for JCP&L. Further, an increase in storm amortization would enable JCP&L to use the cash from deferred storm cost recovery to fund these required capital investments, in turn reducing the level of forecasted borrowings and, thereby, pressure on its credit ratings.

Q. Does this conclude your direct testimony?

A. Yes.

Schedule BW-1

FirstEnergy Corp.
Capitalization

(in millions)	Pro Forma 9/30/2023	%
Total Equity	11,036	32.4%
Long-term Debt	21,726	63.9%
Securitized Debt	400	1.2%
Short-term Borrowings	862	2.5%
Total Capitalization	**$ 34,024**	**100.0%**

JCP&L
Capitalization

(in millions)	Pro Forma 9/30/2023	As Adjusted	Adjusted as of 9/30/2023	%
Short-Term Borrowings	299	(299)	-	0%
			-	0%
Total Equity	4,128	-	4,128	65.8%
Long-term Debt	2,150	-	2,150	34.2%
Total Capitalization	**$ 6,577**	**$ (299)**	**$ 6,278**	**100%**

Schedule BW-2

JCP&L
Capitalization

(in millions)	Adjusted as of 9/30/2023	Exclude Goodwill	Adjusted as of 9/30/2023	%
Total Equity	4,128	(1,811)	2,318	51.9%
Long-term Debt	2,150		2,150	48.1%
Total Capitalization	**$ 6,278**	**$ (1,811)**	**$ 4,467**	**100.0%**

Schedule BW-3

JCP&L
Computation of Long Term Debt Embedded Cost
9/30/2023

Debt Issue	Date of Issue	Date of Maturity	(1) Original Principal Amount	(2) Amount Outstanding	(3) Premium or (Discount) at Issuance	(4) Issuance Expenses	(5) Net Proceeds (1)+(3)-(4)	(6) Net Proceeds Ratio (5)/(1)	(7) Embedded Rate	(8) Embedded Cost (7)*(9)	(9) Adjusted Amount Outstanding (2)*(6)
6.40% Senior Notes	5/12/2006	5/15/2036	200,000,000	200,000,000	(1,216,000)	2,346,872	196,437,128	98.2186	6.536%	12,839,410	196,437,128
6.15% Uns Notes	5/16/2007	6/1/2037	300,000,000	300,000,000	(3,693,000)	327,220	295,979,780	98.6599	6.249%	18,496,143	295,979,780
4.70% Uns Notes	8/21/2013	4/1/2024	500,000,000	500,000,000	(2,595,000)	4,207,350	493,197,650	98.6395	4.865%	23,994,383	493,197,650
4.30% Senior Notes	8/18/2015	1/15/2026	250,000,000	250,000,000	(800,000)	2,113,488	247,086,512	98.8346	4.441%	10,972,171	247,086,512
4.30% Senior Notes	2/8/2019	1/15/2026	400,000,000	400,000,000	5,884,000	3,018,783	402,865,217	100.7163	4.180%	16,837,972	402,865,217
2.75% Senior Notes	6/10/2021	3/1/2032	500,000,000	500,000,000	(1,370,000)	4,509,046	494,120,954	98.8242	2.878%	14,220,488	494,120,954
Sub - Totals				**$2,150,000,000**						**$ 97,360,567**	**$ 2,129,687,240**

Weighted Cost (8) / (9)

Weighted Cost of Long-Term Debt **4.572%**

Schedule BW-4

JCP&L
Weighted Average Cost of Capital

	Ratios	Embedded Cost	Weighted Average Cost of Capital
Total Equity	51.9%	10.40%	5.40%
Long-term Debt	48.1%	4.57%	2.20%
Total Capitalization	100.0%		7.60%

S&P Global
Ratings

Research

Research Update:

FirstEnergy Corp. Subsidiary Ratings Raised; On CreditWatch Positive

October 19, 2021

Rating Action Overview

- On Oct. 18, 2021, FirstEnergy Corp. (FE) created six distinct five-year senior unsecured committed credit facilities to replace the company's two previous credit facilities maturing December 2022.
- S&P Global Ratings believes this measure supplements the existing insulating measures in place. Cumulatively, we view the structural protections and the strength of each operating subsidiaries' stand-alone credit profiles as sufficient to rate FE's regulated utilities up to one notch higher than FE's group credit profile (GCP).
- We are raising our issuer credit ratings (ICRs) to 'BB+' from 'BB' on American Transmission Systems Inc. (ATSI), Cleveland Electric Illuminating Co. (CEI), Jersey Central Power & Light Co. (JCP&L), Mid-Atlantic Interstate Transmission LLC (MAIT), Metropolitan Edison Co. (MetEd), Monongahela Power Co. (MonPower), Ohio Edison Co. (OE), Potomac Edison Co. (PE), Pennsylvania Electric Co. (Penelec), Pennsylvania Power Co. (Penn Power), Toledo Edison Co. (TE), Trans-Allegheny Interstate Line Co. (TrAIL), and West Penn Power Co. (WPP).
- We are affirming all ratings at FE and FirstEnergy Transmission LLC (FET), including the 'BB' ICR, the 'BB' senior unsecured debt ratings, and the 'B+' preferred stock issue-level ratings at FE.
- We are raising the senior secured issue-level ratings at CEI, OE, TE, Penn Power, WPP, PE and MonPower to 'BBB+' from 'BBB', reflecting a '1+' recovery rating. We are also raising the senior unsecured ratings to 'BBB-' from 'BB+' at CEI, OE, MetEd, Penelec, JCP&L, MonPower, ATSI, MAIT, and TrAIL.
- The ratings on FE and its subsidiaries remain on CreditWatch with positive implications, which reflects the probability that we could raise the rating by one or more notches in the coming months based on today's announcement and if the company identifies its long-term funding for its potential penalties and fines or it resolves the remaining investigations and lawsuits against the company, without weakening credit quality.

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Rating Action Rationale

We are upgrading ATSI, CEI, JCP&L, MAIT, MetEd, MonPower, OE, PE, Penelec, Penn Power, TE, TrAIL, and WPP, to 'BB+' from 'BB'. The new credit facility agreements supplement the existing separateness and insulating measures already in place. As such, we assess the cumulative ring-fencing measures as sufficient to rate the utilities one notch above the GCP. Key insulating measures include:

- Each utility is a separate stand-alone legal entity that functions independently (both financially and operationally), files its own rate cases, and is independently regulated.
- Each utility has its own records and books, including stand-alone audited financial statements;
- Each utility has its own funding arrangements, issues its own long-term debt, and has a distinct sublimit under its committed credit facility for its short-term funding needs;
- While the utilities can borrow from FE or FET, neither of the holding companies can borrow from any of the regulated utilities;
- We believe there is a strong economic basis for FE to preserve the entities' credit strength, which reflects the utilities' low-risk, profitable, regulated nature, and that they constitute the majority of FE's operations; and
- There are no cross-default provisions between the utilities and FE or FET that could directly lead to a default at the entities.

There are no changes to our recovery ratings. The senior unsecured debt ratings at FE and FET are based on our '3' recovery ratings, indicating our expectation of meaningful (50%-70%; rounded estimate: 65%) recovery in the event of a payment default. The recovery rating on this debt is capped at '3', consistent with our approach for assigning recovery ratings to unsecured debt issued by 'BB' category corporate entities because recovery prospects are highly vulnerable to impairment before default by additional debt issuance.

The recovery rating for CEI, OE, TE, and MonPower's senior secured first-mortgage bonds is '1+'. Key analytical factors include:

- Our '1+' recovery rating on the senior secured first-mortgage bonds reflects that the value of its regulated utility assets is sufficiently larger than the value of its secured debt.
- The recovery rating indicates our highest expectation for full recovery and results in an issue-level rating three notches above our issuer credit rating. It also reflects the bonds' collateral coverage in excess of 150%, which is consistent with our criteria for recovery ratings on debt issued by regulated utilities and secured by key utility assets.
- A default could occur due to sudden liquidity pressures amid an unpredictable weather, cost, or market event outside the company's control, which is consistent with the conditions of past utility defaults. Furthermore, it could reflect significant future litigation exposure pending the outcomes of the multiple ongoing investigations, criminal allegations, and civil lawsuits at parent FE.
- We expect the entities would continue to operate and reorganize after defaulting given the essential nature of its services. We also assume the value of the utility's assets will be preserved. We use the net value of its regulated fixed assets as a proxy for its enterprise value. We calculate FE's regulated asset value as roughly $33 billion.

The recovery rating on the ATSI, CEI, JCP&L, MAIT, MetEd, MonPower, OE, Penelec, and TrAIL senior unsecured issues is '2'. This is indicative of our expectation of substantial (70%-90%; rounded estimate: 85%) recovery in the event of a payment default. The recovery rating on this debt is capped at '2', consistent with our approach for assigning recovery ratings to unsecured debt issued by 'BB' category regulated utilities because recovery prospects are somewhat vulnerable to impairment before default by additional debt issuance.

CreditWatch

We expect to resolve the CreditWatch placement in the coming months if the company identifies its long-term funding for its potential penalties and fines or it resolves the remaining investigations and lawsuits without weakening credit quality. We expect the company will continue to improve its internal controls and demonstrate improved governance and culture. Effective management of these issues could likely result in an upgrade of one or more notches.

Although unlikely, we could remove the ratings from CreditWatch with positive implications and affirm the ratings if business risk increases, such as a weakening of the company's ability to consistently manage regulatory risk, or if questions remain about the funding of potential penalties and fines, or if financial measures weaken reflecting funds from operations consistently below 9%.

Ratings Score Snapshot

FirstEnergy Corp.

Issuer credit rating: BB/Watch Pos/--

Business risk: Excellent

- Country risk: Very low
- Industry risk: Very low
- Competitive position: Strong

Financial risk: Aggressive

- Cash flow/leverage: Aggressive

Anchor: bbb

Modifiers:

- Diversification/portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Financial policy: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Management and governance: Weak (-2 notches)
- Comparable rating analysis: Negative (-1 notch)

Stand-alone credit profile: bb

- Group credit profile: bb

FirstEnergy Transmission LLC

Issuer Credit Rating: BB/Watch Pos/--

Business risk: Excellent

- Country risk: Very low
- Industry risk: Very low
- Competitive position: Strong

Financial risk: Intermediate

- Cash flow/leverage: Intermediate

Anchor: a+

Modifiers:

- Diversification/portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Financial policy: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Management and governance: Weak (-2 notches)
- Comparable rating analysis: Negative (-1 notch)

Stand-alone credit profile: bbb+

- Group credit profile: bb
- Entity status within group: Core (-4 notches from SACP)

American Transmission Systems Inc.

Issuer Credit Rating: BB+/Watch Pos/--

Business risk: Excellent

- Country risk: Very low
- Industry risk: Very low
- Competitive position: Strong

Financial risk: Intermediate

- Cash flow/leverage: Intermediate

Anchor: a+

Modifiers:

- Diversification/portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Financial policy: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Management and governance: Weak (-2 notches)
- Comparable rating analysis: Neutral (no impact)

Stand-alone credit profile: a-

- Group credit profile: bb
- Entity status within group: Insulated

Cleveland Electric Illuminating Co.

Issuer Credit Rating: BB+/Watch Pos/--

Business risk: Excellent

- Country risk: Very low
- Industry risk: Very low
- Competitive position: Strong

Financial risk: Significant

- Cash flow/leverage: Significant

Anchor: a-

Modifiers:

- Diversification/portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Financial policy: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Management and governance: Weak (-2 notches)
- Comparable rating analysis: Neutral (no impact)

Stand-alone credit profile: bbb

- Group credit profile: bb
- Entity status within group: Insulated

Jersey Central Power & Light Co.

Issuer Credit Rating: BB+/Watch Pos/NR

Business risk: Strong

- Country risk: Very low
- Industry risk: Very low
- Competitive position: Satisfactory

Financial risk: Significant

- Cash flow/leverage: Significant

Anchor: bbb

Modifiers:

- Diversification/portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Financial policy: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Management and governance: Weak (-2 notches)
- Comparable rating analysis: Neutral (no impact)

Stand-alone credit profile: bb+

- Group credit profile: bb
- Entity status within group: Insulated

Metropolitan Edison Co.

Issuer Credit Rating: BB+/Watch Pos/NR

Business risk: Excellent

- Country risk: Very low
- Industry risk: Very low
- Competitive position: Strong

Financial risk: Significant

- Cash flow/leverage: Significant

Anchor: a-

Modifiers:

- Diversification/portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Financial policy: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Management and governance: Weak (-2 notches)

- Comparable rating analysis: Neutral (no impact)

Stand-alone credit profile: bbb

- Group credit profile: bb
- Entity status within group: Insulated

Mid-Atlantic Interstate Transmission LLC

Issuer Credit Rating: BB+/Watch Pos/--

Business risk: Excellent

- Country risk: Very low
- Industry risk: Very low
- Competitive position: Excellent

Financial risk: Intermediate

- Cash flow/leverage: Intermediate

Anchor: a+

Modifiers:

- Diversification/portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Financial policy: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Management and governance: Weak (-2 notches)
- Comparable rating analysis: Neutral (no impact)

Stand-alone credit profile: a-

- Group credit profile: bb
- Entity status within group: Insulated

Monongahela Power Co.

Issuer Credit Rating: BB+/Watch Pos/NR

Business risk: Strong

- Country risk: Very low
- Industry risk: Very low
- Competitive position: Satisfactory

Financial risk: Significant

- Cash flow/leverage: Significant

Anchor: bbb

Modifiers:

- Diversification/portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Financial policy: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Management and governance: Weak (-2 notches)
- Comparable rating analysis: Neutral (no impact)

Stand-alone credit profile: bb+

- Group credit profile: bb
- Entity status within group: Insulated

Ohio Edison Co.

Issuer Credit Rating: BB+/Watch Pos/B

Business risk: Excellent

- Country risk: Very low
- Industry risk: Very low
- Competitive position: Strong

Financial risk: Modest

- Cash flow/leverage: Modest

Anchor: aa

Modifiers:

- Diversification/portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Financial policy: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Management and governance: Weak (-2 notches)
- Comparable rating analysis: Negative (-1 notch)

Stand-alone credit profile: a

- Group credit profile: bb
- Entity status within group: Insulated

Pennsylvania Electric Co.

Issuer Credit Rating: BB+/Watch Pos/NR

Business risk: Excellent

- Country risk: Very low
- Industry risk: Very low
- Competitive position: Strong

Financial risk: Significant

- Cash flow/leverage: Significant

Anchor: a-

Modifiers:

- Diversification/portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Financial policy: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Management and governance: Weak (-2 notches)
- Comparable rating analysis: Neutral (no impact)

Stand-alone credit profile: bbb

- Group credit profile: bb
- Entity status within group: Insulated

Pennsylvania Power Co.

Issuer Credit Rating: BB+/Watch Pos/--

Business risk: Excellent

- Country risk: Very low
- Industry risk: Very low
- Competitive position: Strong

Financial risk: Intermediate

- Cash flow/leverage: Intermediate

Anchor: a+

Modifiers:

- Diversification/portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)

- Financial policy: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Management and governance: Weak (-2 notches)
- Comparable rating analysis: Neutral (no impact)

Stand-alone credit profile: a-

- Group credit profile: bb
- Entity status within group: Insulated

Potomac Edison Co.

Issuer Credit Rating: BB+/Watch Pos/NR

Business risk: Strong

- Country risk: Very low
- Industry risk: Very low
- Competitive position: Satisfactory

Financial risk: Significant

- Cash flow/leverage: Significant

Anchor: bbb

Modifiers:

- Diversification/portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Financial policy: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Management and governance: Weak (-2 notches)
- Comparable rating analysis: Neutral (no impact)

Stand-alone credit profile: bb+

- Group credit profile: bb
- Entity status within group: Insulated

Toledo Edison Co.

Issuer Credit Rating: BB+/Watch Pos/--

Business risk: Excellent

- Country risk: Very low
- Industry risk: Very low

- Competitive position: Strong

Financial risk: Significant

- Cash flow/leverage: Significant

Anchor: a-

Modifiers:

- Diversification/portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Financial policy: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Management and governance: Weak (-2 notches)
- Comparable rating analysis: Neutral (no impact)

Stand-alone credit profile: bbb

- Group credit profile: bb
- Entity status within group: Insulated

Trans-Allegheny Interstate Line Co.

Issuer Credit Rating: BB+/Watch Pos/--

Business risk: Excellent

- Country risk: Very low
- Industry risk: Very low
- Competitive position: Excellent

Financial risk: Modest

- Cash flow/leverage: Modest

Anchor: aa

Modifiers:

- Diversification/portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Financial policy: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Management and governance: Weak (-2 notches)
- Comparable rating analysis: Neutral (no impact)

Stand-alone credit profile: a+

- Group credit profile: bb
- Entity status within group: Insulated

West Penn Power Co.

Issuer Credit Rating: BB+/Watch Pos/--

Business risk: Excellent

- Country risk: Very low
- Industry risk: Very low
- Competitive position: Strong

Financial risk: Intermediate

- Cash flow/leverage: Intermediate

Anchor: a+

Modifiers:

- Diversification/portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Financial policy: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Management and governance: Weak (-2 notches)
- Comparable rating analysis: Negative (-1 notch)

Stand-alone credit profile: bbb+

- Group credit profile: bb
- Entity status within group: Insulated

Related Criteria

- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10, 2021
- General Criteria: Group Rating Methodology, July 1, 2019
- General Criteria: Hybrid Capital: Methodology And Assumptions, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- General Criteria: Methodology For Linking Long-Term And Short-Term Ratings, April 7, 2017
- Criteria | Corporates | General: Recovery Rating Criteria For Speculative-Grade Corporate Issuers, Dec. 7, 2016
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014

- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- Criteria | Corporates | General: Corporate Methodology, Nov. 19, 2013
- Criteria | Corporates | Utilities: Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- General Criteria: Methodology: Management And Governance Credit Factors For Corporate Entities, Nov. 13, 2012
- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

Related Research

- "Research Update: FirstEnergy Corp. And Subsidiaries Ratings On CreditWatch Positive Following Deferred Prosecution Agreement," July 23, 2021

Ratings List

Ratings Affirmed		
FirstEnergy Corp.		
FirstEnergy Transmission LLC		
Issuer Credit Rating	BB/Watch Pos/--	
Ratings Upgraded		
	To	**From**
American Transmission Systems Inc.		
Trans-Allegheny Interstate Line Co.		
Toledo Edison Co.		
Pennsylvania Power Co.		
Mid-Atlantic Interstate Transmission LLC		
Cleveland Electric Illuminating Co.		
Jersey Central Power & Light Co.		
West Penn Power Co.		
Potomac Edison Co.		
Pennsylvania Electric Co.		
Monongahela Power Co.		
Metropolitan Edison Co.		
Issuer Credit Rating	BB+/Watch Pos/--	BB/Watch Pos/--
Ohio Edison Co.		
Issuer Credit Rating	BB+/Watch Pos/B	BB/Watch Pos/B

Issue-Level Ratings Affirmed; Recovery Ratings Unchanged		
FirstEnergy Corp.		
Senior Unsecured	BB/Watch Pos	
Recovery Rating	3(65%)	
Preferred Stock	B+/Watch Pos	
FirstEnergy Transmission LLC		
Senior Unsecured	BB/Watch Pos	
Recovery Rating	3(65%)	
Issue-Level Ratings Raised; Recovery Ratings Unchanged		
American Transmission Systems Inc.		
Senior Unsecured	BBB-/Watch Pos	BB+/Watch Pos
Recovery Rating	2(85%)	2(85%)
Cleveland Electric Illuminating Co.		
Senior Secured	BBB+/Watch Pos	BBB/Watch Pos
Recovery Rating	1+	1+
Senior Unsecured	BBB-/Watch Pos	BB+/Watch Pos
Recovery Rating	2(85%)	2(85%)
Jersey Central Power & Light Co.		
Senior Unsecured	BBB-/Watch Pos	BB+/Watch Pos
Recovery Rating	2(85%)	2(85%)
Metropolitan Edison Co.		
Senior Unsecured	BBB-/Watch Pos	BB+/Watch Pos
Recovery Rating	2(85%)	2(85%)
Mid-Atlantic Interstate Transmission LLC		
Senior Unsecured	BBB-/Watch Pos	BB+/Watch Pos
Recovery Rating	2(85%)	2(85%)
Monongahela Power Co.		
Senior Secured	BBB+/Watch Pos	BBB/Watch Pos
Recovery Rating	1+	1+
Ohio Edison Co.		
Senior Secured	BBB+/Watch Pos	BBB/Watch Pos
Recovery Rating	1+	1+
Senior Unsecured	BBB-/Watch Pos	BB+/Watch Pos
Recovery Rating	2(85%)	2(85%)
Pennsylvania Electric Co.		
Senior Unsecured	BBB-/Watch Pos	BB+/Watch Pos
Recovery Rating	2(85%)	2(85%)
Pennsylvania Power Co.		
Senior Secured	BBB+/Watch Pos	BBB/Watch Pos

Recovery Rating	1+	1+
Potomac Edison Co.		
Senior Secured	BBB+/Watch Pos	BBB/Watch Pos
Recovery Rating	1+	1+
Toledo Edison Co.		
Senior Secured	BBB+/Watch Pos	BBB/Watch Pos
Recovery Rating	1+	1+
Trans-Allegheny Interstate Line Co.		
Senior Unsecured	BBB-/Watch Pos	BB+/Watch Pos
Recovery Rating	2(85%)	2(85%)
West Penn Power Co.		
Senior Secured	BBB+/Watch Pos	BBB/Watch Pos
Recovery Rating	1+	1+

Certain terms used in this report, particularly certain adjectives used to express our view on rating relevant factors, have specific meanings ascribed to them in our criteria, and should therefore be read in conjunction with such criteria. Please see Ratings Criteria at www.standardandpoors.com for further information. Complete ratings information is available to subscribers of RatingsDirect at www.capitaliq.com. All ratings affected by this rating action can be found on S&P Global Ratings' public website at www.standardandpoors.com. Use the Ratings search box located in the left column.

EXHIBIT JC-7

BEFORE THE
NEW JERSEY BOARD OF PUBLIC UTILITIES

In the Matter of the Verified Petition of Jersey Central Power & Light Company for Review and Approval of Increases in, and Other Adjustments to, Its Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith

Direct Testimony

of

Dylan W. D'Ascendis, CRRA, CVA
Partner, ScottMadden, Inc.

Re:
Return On Common Equity

TABLE OF CONTENTS

I. INTRODUCTION AND BACKGROUND

A. Witness Identification

Q. Please state your name and business address.

A. My name is Dylan W. D'Ascendis. My business address is 3000 Atrium Way, Suite 200, Mount Laurel, New Jersey 08054.

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

A. I am a Partner at ScottMadden, Inc.

Q. Have you previously testified in Board of Public Utilities ("BPU") proceedings?

A. Yes, I have.

Q. Please summarize your professional experience and educational background.

A. I have offered expert testimony on behalf of investor-owned utilities before over 35 state regulatory commissions in the United States, the Federal Energy Regulatory Commission, the Alberta Utility Commission, an American Arbitration Association panel, and the Superior Court of Rhode Island on issues including, but not limited to, common equity cost rate, rate of return, valuation, capital structure, class cost of service, and rate design.

On behalf of the American Gas Association ("AGA"), I calculate the AGA Gas Index, which serves as the benchmark against which the performance of the American Gas Index Fund ("AGIF") is measured on a monthly basis. The AGA Gas Index and AGIF are a market capitalization weighted index and mutual fund,

respectively, comprised of the common stocks of the publicly traded corporate members of the AGA.

I am a member of the Society of Utility and Regulatory Financial Analysts ("SURFA"). In 2011, I was awarded the professional designation "Certified Rate of Return Analyst" by SURFA, which is based on education, experience, and the successful completion of a comprehensive written examination.

I am also a member of the National Association of Certified Valuation Analysts ("NACVA") and was awarded the professional designation "Certified Valuation Analyst" by NACVA in 2015.

I am a graduate of the University of Pennsylvania, where I received a Bachelor of Arts degree in Economic History. I have also received a Master of Business Administration with high honors and concentrations in Finance and International Business from Rutgers University.

The details of my educational background and expert witness appearances are shown in Appendix A.

Q. Please describe the purpose of your testimony.

A. The purpose of my testimony is to present evidence on behalf of Jersey Central Power & Light Company ("JCP&L" or the "Company") and recommend an allowed rate of return on common equity ("ROE") for its New Jersey jurisdictional rate base.

Q. Have you prepared schedules in support of your recommendation?

A. Yes. I have prepared Schedules DWD-1 through DWD-8, which were prepared by me or under my direction.

Q. What is your recommended ROE for JCP&L?

A. I recommend that the New Jersey Board of Public Utilities (the "Board") authorize JCP&L the opportunity to earn an ROE of 10.40% on its jurisdictional rate base. The ratemaking capital structure and cost of long-term debt is sponsored by Company Witness Bill Wang. The overall rate of return is summarized on page 1 of Schedule DWD-1 and in Table 1 below:

Table 1: Summary of Recommended Weighted Average Cost of Capital

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	48.10%	4.572%	2.20%
Common Equity	51.90%	10.40%	5.40%
Total	100.00%		7.60%

II. SUMMARY

Q. Please summarize your recommended common equity cost rate.

A. My recommended common equity cost rate of 10.40% is summarized on page 2 of Schedule DWD-1. I have assessed the market-based common equity cost rates of companies of relatively similar, but not necessarily identical, risk to JCP&L. Using companies of relatively comparable risk as proxies is consistent with the principles of fair rate of return established in the *Hope*[1] and *Bluefield*[2] decisions. No proxy group can be identical in risk to any single company. Consequently, there must be an evaluation of relative risk between the company and the proxy group to determine if it is appropriate to adjust the proxy group's indicated rate of return.

My recommendation results from applying several cost of common equity models, specifically the Discounted Cash Flow ("DCF") model, the Risk Premium

[1] *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("Hope").
[2] *Bluefield Water Works Improvement Co. v. Public Serv. Comm'n*, 262 U.S. 679 (1922) ("Bluefield").

Model ("RPM"), and the Capital Asset Pricing Model ("CAPM"), to the market data of a proxy group of 13 electric utilities ("Utility Proxy Group") whose selection criteria will be discussed below. In addition, I applied the DCF model, RPM, and CAPM to a proxy group of 50 domestic, non-price regulated companies comparable in total risk to the Utility Proxy Group ("Non-Price Regulated Proxy Group"). The results derived from each are as follows:

Table 2: Summary of Common Equity Cost Rates

Discounted Cash Flow Model	9.29%
Risk Premium Model	11.64%
Capital Asset Pricing Model	11.79%
Cost of Equity Models Applied to Comparable Risk, Non-Price Regulated Companies	12.58%
Indicated Range of Common Equity Cost Rates Before Adjustments	10.04% - 11.04%
Size Adjustment	0.15%
Credit Risk Adjustment	-0.10%
Flotation Cost Adjustment	0.19%
Indicated Cost of Common Equity Cost Rates After Adjustment	10.28% - 11.28%
Recommended Cost of Common Equity	10.40%

The indicated common equity cost rates across these models is from 10.04% to 11.04% before any Company-specific adjustments.[3] I then adjusted the indicated common equity cost rate upward by 0.15% to reflect the Company's smaller relative size and downward by 0.10% to reflect the Company's less risky bond rating, as compared to the Utility Proxy Group companies, and upward by 0.19% for flotation

[3] My indicated range of common equity cost rates are 50 basis points above and below the midpoint of my four model results.

costs. These adjustments resulted in a Company-specific range of indicated common equity cost rates between 10.28% and 11.28%. From this range, I recommend that the Board authorize an ROE of 10.40% for the Company.

Q. How is the remainder of your direct testimony organized?

A. The remainder of my Direct Testimony is organized as follows:

- *Section III* – Provides a summary of financial theory and regulatory principles pertinent to the development of the Cost of Capital;
- *Section IV* – Explains my selection of the Utility Proxy Group used to develop my analytical results;
- *Section V* – Describes the analyses on which my recommendation is based;
- *Section VI* – Summarizes my common equity cost rate before adjustments to reflect Company-specific factors;
- *Section VII* – Explains my adjustments to my common equity cost rate to reflect the Company-specific factors; and
- *Section VIII* – Presents my conclusions.

III. GENERAL PRINCIPLES

Q. What general principles have you considered in arriving at your recommended common equity cost rate?

A. In unregulated industries, marketplace competition is the principal determinant of the price of products or services. For regulated public utilities, regulation must act as a substitute for marketplace competition. Assuring that the utility can fulfill its obligations to the public, while providing safe and reliable service, requires a level of earnings sufficient to maintain the integrity of presently invested capital.

Sufficient earnings also permit the attraction of needed new capital at a reasonable cost, for which the utility must compete with other firms of comparable risk, consistent with the fair rate of return standards established by the U.S. Supreme Court in the previously cited *Hope* and *Bluefield* cases.

The U.S. Supreme Court affirmed the fair rate of return standards in *Hope*, when it stated:

> The rate-making process under the Act, i.e., the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests. Thus we stated in the Natural Gas Pipeline Co. case that 'regulation does not insure that the business shall produce net revenues.' 315 U.S. at page 590, 62 S.Ct. at page 745. But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. 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. Cf. Chicago & Grand Trunk R. Co. v. Wellman, 143 U.S. 339, 345, 346 12 S.Ct. 400, 402. 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.[4]

In summary, the U.S. Supreme Court has found a fair rate of return is one that is adequate to attract capital at reasonable terms and enables the utility to provide service while maintaining its financial integrity. As discussed above, and in keeping with established regulatory standards, that return should be commensurate with the returns expected elsewhere for investments of equivalent risk. The Board's decision in this proceeding, therefore, should provide the Company with the opportunity to earn a return that is: (1) adequate to attract capital

[4] *Hope*, 320 U.S. 591, 603 (1944).

at reasonable cost and terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises having corresponding risks.

Lastly, the required return for a regulated public utility is established on a stand-alone basis, i.e., for the utility operating company at issue in a rate case. Parent entities, like other investors, have capital constraints and must look at the attractiveness of the expected risk-adjusted return of each investment alternative in their capital budgeting process. That is, utility holding companies that own many utility operating companies have choices as to where they will invest their capital within the holding company family. Therefore, the opportunity cost concept applies regardless of whether the funding source is public or corporate.

When funding is provided by a parent entity, the return still must be sufficient to provide an incentive to allocate equity capital to the subsidiary or business unit rather than other internal or external investment opportunities. That is, the regulated subsidiary must compete for capital with all the parent company's affiliates, and with other similar risk companies, which may include non-utilities. In that regard, investors value corporate entities on a sum-of-the-parts basis and expect each division within the parent company to provide an appropriate risk-adjusted return.

It therefore is important that the authorized ROE for the Company reflects the risks and prospects of its operations and supports its financial integrity from a stand-alone perspective. Consequently, the ROE authorized in this proceeding should be sufficient to support the operational (i.e., business risk) and financing

(i.e., financial risk) of the Company's utility operations on a stand-alone basis. In unregulated industries, the competition of the marketplace is the principal determinant of the price of products or services. For regulated public utilities, regulation must act as a substitute for marketplace competition. Assuring that the utility can fulfill its obligations to the public, while providing safe and reliable service, requires a level of earnings sufficient to maintain the integrity of presently invested capital. Sufficient earnings also permit the attraction of needed new capital at a reasonable cost, for which the utility must compete with other firms of comparable risk, consistent with the fair rate of return standards established by the U.S. Supreme Court in the previously cited *Hope* and *Bluefield* decisions. Consequently, marketplace data must be relied on in assessing a common equity cost rate appropriate for ratemaking purposes. Just as the use of the market data for the proxy group adds reliability to the informed expert's judgment used in arriving at a recommended common equity cost rate, the use of multiple, generally accepted common equity cost rate models also adds reliability and accuracy when arriving at a recommended common equity cost rate.

Q. Within that broad framework, how is the cost of capital estimated in regulatory proceedings?

A. Regulated utilities primarily use common stock and long-term debt to finance their permanent property, plant, and equipment (i.e., rate base). The fair rate of return for a regulated utility is based on its weighted average cost of capital, in which, as noted earlier, the costs of the individual sources of capital are weighted by their respective book values.

The cost of capital is the return investors require to make an investment in a firm. Investors will provide funds to a firm only if the return that they *expect* is equal to, or greater than, the return that they *require* to accept the risk of providing funds to the firm.

The cost of capital (that is, the combination of the costs of debt and equity) is based on the economic principle of "opportunity costs." The principle of opportunity costs recognizes that investing in any asset (whether debt or equity securities) represents a forgone opportunity to invest in alternative assets. For any investment to be sensible, its expected return must be at least equal to the return expected on alternative investment opportunities with comparable risks. Because investments with like risks should offer similar returns, the opportunity cost of an investment should equal the return available on an investment of comparable risk.

The cost of debt is contractually defined and can be directly observed as the interest rate or yield on debt securities. However, the cost of equity is not directly observable and must be estimated based on market data and various financial models. Because the cost of equity is premised on opportunity costs, the models used to determine it are typically applied to a group of "comparable" or "proxy" companies.

In the end, the estimated cost of capital should reflect the return that investors require in light of the subject company's business and financial risks, and the returns available on comparable investments.

A. Business Risk

Q. Please define business risk and explain why it is important for determining a fair rate of return.

A. The investor-required return on common equity reflects investors' assessment of the total investment risk of the subject firm. Total investment risk is often discussed in the context of business and financial risk.

Business risk reflects the uncertainty associated with owning a company's common stock without the company's use of debt and/or preferred stock financing. One way of considering the distinction between business and financial risk is to view the former as the uncertainty of the expected earned return on common equity, assuming the firm is financed with no debt.

Examples of business risks generally faced by utilities include, but are not limited to, the regulatory environment, mandatory environmental compliance requirements, customer mix and concentration of customers, service territory economic growth, market demand, operations, capital intensity, size, the degree of operating leverage, emerging technologies including distributed energy resources, the vagaries of weather, and the like, all of which have a direct bearing on earnings.

Although analysts, including rating agencies, may categorize business risks individually, as a practical matter, such risks are interrelated and not wholly distinct from one another. When determining an appropriate return on common equity, the relevant issue is where investors see the subject company in relation to other similarly situated utility companies (i.e., the Utility Proxy Group). To the extent

investors view a company as being exposed to higher risk, the required return will increase, and vice versa.

For regulated utilities, business risks are both long-term and near-term in nature. Whereas near-term business risks are reflected in year-to-year variability in earnings and cash flow brought about by economic or regulatory factors, long-term business risks reflect the prospect of an impaired ability of investors to obtain both a fair rate of return on, and return of, their capital. Moreover, because utilities accept the obligation to provide safe, adequate and reliable service (in exchange for a reasonable opportunity to earn a fair return on their investment), they generally do not have the option to delay, defer, or reject capital investments. Because those investments are capital-intensive, utilities generally do not have the option to avoid raising external funds. The obligation to serve and the corresponding need to access capital is even more acute during periods of capital market distress.

Because utilities invest in long-lived assets, long-term business risks are of paramount concern to equity investors. That is, the risk of not recovering the return on their investment extends far into the future. The timing and nature of events that may lead to losses, however, also are uncertain and, consequently, those risks and their implications for the required return on equity tend to be difficult to quantify. Regulatory commissions (like investors who commit their capital) must review a variety of quantitative and qualitative data and apply their reasoned judgment to determine how long-term risks weigh in their assessment of the market-required return on common equity.

B. Financial Risk

Q. Please define financial risk and explain why it is important in determining a fair rate of return.

A. Financial risk is the additional risk created by the introduction of debt and preferred stock into the capital structure. The higher the proportion of debt and preferred stock in the capital structure, the higher the financial risk to common equity owners (i.e., failure to receive dividends due to default or other covenants). Therefore, consistent with the basic financial principle of risk and return, common equity investors require higher returns as compensation for bearing higher financial risk.

Q. Can bond and credit ratings be a proxy for a firm's combined business and financial risks to equity owners (i.e., investment risk)?

A. Yes, similar bond ratings/issuer credit ratings reflect, and are representative of, similar combined business and financial risks (i.e., total risk) faced by bond investors.[5] Although specific business or financial risks may differ between companies, the same bond/credit rating indicates that the combined risks are roughly similar from a debtholder perspective. The caveat is that these debtholder risk measures do not translate directly to risks for common equity.

[5] Risk distinctions within S&P's bond rating categories are recognized by a plus or minus, e.g., within the A category, an S&P rating can by at A+, A, or A-. Similarly, risk distinction for Moody's ratings are distinguished by numerical rating gradations, e.g., within the A category, a Moody's rating can be A1, A2 and A3.

IV. JCP&L AND THE UTILITY PROXY GROUP

Q. Why is it necessary to develop a proxy group when estimating the ROE for JCP&L?

A. Because JCP&L is not publicly traded and does not have publicly traded equity securities, it is necessary to develop groups of publicly traded, comparable companies to serve as "proxies" for the Company. In addition to the analytical necessity of doing so, the use of proxy companies is consistent with the *Hope* and *Bluefield* comparable risk standards, as discussed above. I have selected two proxy groups that, in my view, are fundamentally risk-comparable to the Company: a Utility Proxy Group and a Non-Price Regulated Proxy Group, which is comparable in total risk to the Utility Proxy Group.[6]

Even when proxy groups are carefully selected, it is common for analytical results to vary from company to company. Despite the care taken to ensure comparability, because no two companies are identical, market expectations regarding future risks and prospects will vary within the proxy group. It, therefore, is common for analytical results to reflect a seemingly wide range, even for a group of similarly situated companies. At issue is how to estimate the ROE from within that range. That determination will be best informed by employing a variety of sound analyses and necessarily must consider the sort of quantitative and qualitative information discussed throughout my Direct Testimony. Additionally, a relative risk analysis between the Company and the Utility Proxy Group must be made to

[6] The development of the Non-Price Regulated Proxy Group is explained in more detail in Section V, part D.

determine whether or not explicit Company-specific adjustments need to be made to the Utility Proxy Group indicated results.

My analyses are based on the Utility Proxy Group, containing U.S. electric utilities. As discussed earlier, utilities must compete for capital with other companies with commensurate risk (including non-utilities) and, to do so, must be provided the opportunity to earn a fair and reasonable return. Consequently, it is appropriate to consider the Utility Proxy Group's market data in determining the Company's ROE.

Q. Are you familiar with JCP&L's operations?

A. Yes. JCP&L serves approximately 1.1 million customers in 13 counties within northern, western, and east central New Jersey. JCP&L is not publicly-traded as it is an operating subsidiary of FirstEnergy Corp. ("FE" or the "Parent"), which operates in six states[7], serves approximately six million customers, and is publicly-traded under symbol FE.

Q. In its order in *In The Matter of the Business Combination of FirstEnergy Corp., Parent Company of Jersey Central Power & Light Company, and Allegheny Energy, Inc.*, the BPU directed that JCP&L, in future rate proceedings, "to the extent reasonable . . . include in the 'comparables' group 'distribution only' utilities or utilities with the majority of their assets under regulation, but may include other types of 'comparables' as deemed appropriate by its expert ROE

[7] FirstEnergy Corp., 2021 SEC Form 10-K, at 1, In addition to New Jersey, FE also serves customers in Ohio, Pennsylvania, West Virginia, Maryland, and New York.

witness." Did you make an attempt to include "distribution only" utilities in the electric proxy group?

A. Yes. The electric and combination electric and gas utility industries are characterized by large holding company corporate structures, with many mergers and acquisitions having occurred since the deregulation of the late 1990s. Hence, most vertically integrated holding companies retained their generation operations in affiliated subsidiaries, separate and distinct from the "distribution only" regulated utility, when they restructured. As a consequence, most of the electric and combination electric and gas holding companies currently have both "distribution only" and "vertically integrated" subsidiaries. Therefore, there are currently too few publicly traded electric or combination electric and gas companies which are "distribution only" meeting my selection criteria, making it impossible to select a proxy group of comparable utilities which are "distribution only."

Since it was not possible to select a group of publicly traded electric or combination electric and gas companies comparable to JCP&L which are entirely "distribution only" companies, I applied the selection criteria described below to choose the Electric Proxy Group.

Q. Please explain how you chose the companies in the utility proxy group.

A. Because the cost of equity is a comparative exercise, my objective in developing a proxy group was to select companies that are comparable to the Company. Because the Company is a 100% rate-regulated, transmission and distribution electric utility, I applied the following criteria to select my Utility Proxy Group:

(i) They were included in the Eastern, Central, or Western Electric Utility Group of *Value Line Investment Survey* (Standard Edition)(*"Value Line"*);

(ii) They have 70% or greater of fiscal year 2021 total operating income derived from, and 70% or greater of fiscal year 2021 total assets attributable to, regulated electric distribution operations;

(iii) At the time of preparation of this testimony, they had not publicly announced that they were involved in any major merger or acquisition activity (i.e., one publicly-traded utility merging with or acquiring another) or any other major development;

(iv) They have not cut or omitted their common dividends during the five years ending 2021 or through the time of preparation of this testimony;

(v) They have *Value Line* and Bloomberg Professional Services ("Bloomberg") adjusted Beta coefficients ("beta");

(vi) They have positive *Value Line* five-year dividends per share ("DPS") growth rate projections; and

(vii) They have *Value Line*, Zacks, or Yahoo! Finance consensus five-year earnings per share ("EPS") growth rate projections.

The following 13 companies met these criteria:

Table 3: Utility Proxy Group Companies

Company Name	Ticker Symbol
Alliant Energy Corporation	LNT
Ameren Corporation	AEE
American Electric Power Corporation	AEP
Duke Energy Corporation	DUK
Edison International	EIX
Entergy Corporation	ETR
Evergy, Inc.	EVRG
Eversource Energy	ES
IDACORP, Inc.	IDA
NorthWestern Corporation	NWE
OGE Energy Corporation	OGE
Portland General Electric Company	POR
Xcel Energy Inc.	XEL

V. COMMON EQUITY COST RATE MODELS

Q. Is it important that cost of common equity models be market-based?

A. Yes. As previously discussed, regulated public utilities, like the Company, must compete for equity in capital markets along with all other companies with commensurate risk, including non-utilities. The cost of common equity is thus determined based on equity market expectations for the returns of those companies. If an individual investor is choosing to invest their capital among companies with comparable risk, they will choose the company providing a higher return over a company providing a lower return.

Q. Are the cost of common equity models you use market-based models?

A. Yes. The DCF model is market-based in that market prices are used in developing the dividend yield component of the model. The RPM and CAPM are also market-based in that the bond/issuer ratings and expected bond yields/risk-free rate used in the application of the RPM and CAPM reflect the market's assessment of bond/credit risk. In addition, the use of beta to determine the equity risk premium

also reflects the market's assessment of market/systematic risk, as betas are derived from regression analyses of market prices. Moreover, market prices are used in the development of the monthly returns and equity risk premiums used in the Predictive Risk Premium Model ("PRPM"), which is a component of the RPM. Selection criteria for the Non-Price Regulated Proxy Group are based on regression analyses of market prices and reflect the market's assessment of total risk.

Q. What analytical approaches did you use to determine the company's ROE?

A. As discussed earlier, I have relied on the DCF model, the RPM, and the CAPM, which I apply to the Utility Proxy Group described above. I also applied these same models to a Non-Price Regulated Proxy Group described later in this section.

I rely on multiple models because reasonable investors use a variety of tools and do not rely exclusively on a single source of information or single model. Moreover, the specific models on which I rely focus on different aspects of return requirements and provide different insights into investors' views of risk and return. The DCF model, for example, estimates the investor-required return assuming a constant expected dividend yield and growth rate in perpetuity, while Risk Premium-based methods (i.e., the RPM and CAPM approaches) provide the ability to reflect investors' views of risk, future market returns, and the relationship between interest rates and the ROE. Just as the use of market data for the Utility Proxy Group adds the reliability necessary to inform expert judgment in arriving at a recommended common equity cost rate, the use of multiple generally accepted common equity cost rate models also adds reliability and accuracy when arriving at a recommended common equity cost rate.

A. Discounted Cash Flow Model

Q. Please describe the DCF model, generally.

A. The theory underlying the DCF model is that the present value of an expected future stream of net cash flows during the investment holding period can be determined by discounting those cash flows at the cost of capital, or the investors' capitalization rate. DCF theory indicates that an investor buys a stock for an expected total return rate, which is derived from the cash flows received from dividends and market price appreciation. Mathematically, the dividend yield on market price plus a growth rate equals the capitalization rate; i.e., the total common equity return rate expected by investors, as shown in Equation [1] below:

$$K_e = (D_0 (1+g))/P + g$$

where:

K_e = the required Return on Equity;

D_0 = the annualized Dividend Per Share;

P = the current stock price; and

g = the growth rate.

Q. Which version of the DCF model do you use?

A. I used the single-stage constant growth DCF model.

Q. Please describe the dividend yield you used in applying the constant growth DCF model.

A. The unadjusted dividend yields are based on the proxy companies' dividends as of December 30, 2022, divided by the average closing market price for the 60 trading days ended December 30, 2022.[8]

Q. Please explain your adjustment to the dividend yield.

A. Because dividends are paid periodically (e.g., quarterly), as opposed to continuously (daily), an adjustment must be made to the dividend yield. This is often referred to as the discrete, or the Gordon Periodic, version of the DCF model.

DCF theory calls for using the full growth rate, or D_1, in calculating the model's dividend yield component. Since the companies in the Utility Proxy Group increase their quarterly dividends at various times during the year, a reasonable assumption is to reflect one-half the annual dividend growth rate in the dividend yield component, or $D_{1/2}$. Because the dividend should be representative of the next 12-month period, this adjustment is a conservative approach that does not overstate the dividend yield. Therefore, the actual average dividend yields in Column 1, page 1 of Schedule DWD-2 have been adjusted upward to reflect one-half the average projected growth rate shown in Column 5.

[8] *See*, Column 1, page 1 of Schedule DWD-2.

Q. Please explain the basis for the growth rates you apply to the utility proxy group in your constant growth DCF model.

A. Investors with more limited resources than institutional investors are likely to rely on widely available financial information services, such as *Value Line*, Zacks, and Yahoo! Finance. Investors realize that analysts have significant insight into the dynamics of the industries and individual companies they analyze, as well as companies' abilities to effectively manage the effects of changing laws and regulations, and ever-changing economic and market conditions. For these reasons, I used analysts' five-year forecasts of EPS growth in my DCF analysis.

Over the long run, there can be no growth in DPS without growth in EPS. Security analysts' earnings expectations have a more significant influence on market prices than dividend expectations. Thus, using earnings growth rates in a DCF analysis provides a better match between investors' market price appreciation expectations and the growth rate component of the DCF.

Q. Please summarize the constant growth DCF model results.

A. As shown on page 1 of Schedule DWD-2, the application of the Constant Growth DCF model to the Utility Proxy Group results in a wide range of indicated ROEs from 6.70% to 12.65%. The mean of those results is 9.24%, the median result is 9.34%, and the average of the mean and median result is 9.29%. In arriving at a conclusion for the constant growth DCF-indicated common equity cost rate for the Utility Proxy Group, I relied on an average of the mean and the median results (i.e., 9.29%) of the DCF. By doing so, I have considered the DCF results for each company without giving undue weight to outliers on either the high or low side.

The DCF results should be viewed with caution, however, as the DCF model is currently understating the investor-required return.

Q. As shown on table 2 above, the DCF results appear significantly lower compared to the rest of your model results. Are there any specific weaknesses of the DCF model necessitating the use of multiple common equity cost rate models?

A. Yes. The DCF model presumes that market-to-book ("M/B") ratios are at unity or 1.00. However, that is rarely the case. Morin states:

> The third and perhaps most important reason for caution and skepticism is that application of the DCF model produces estimates of common equity cost that are consistent with investors' expected return only when stock price and book value are reasonably similar, that is, when the M/B is close to unity. As shown below, application of the standard DCF model to utility stocks understates the investor's expected return when the M/B ratio of a given stock exceeds unity. This was particularly relevant in the capital market environment of the early 2020s when utility stocks are trading at M/B ratios well above unity and have been for nearly two decades. The converse is also true, that is, the DCF model overstates the investor's return when the stock's M/B ratio is less than unity. The reason for the distortion is that the DCF market return is applied to a book value rate base by the regulator, that is, a utility's earnings are limited to earnings on a book value rate base.[9]

Since the "simplified" DCF model traditionally used in rate regulation assumes a M/B ratio of 1.00, it understates/overstates investors' required return rate when market value exceeds or is less than book value. It does so because utility investors evaluate and receive their returns on the market value of a utility's equity, whereas regulators authorize returns on book common equity. This means the

[9] Roger A. Morin, Modern Regulatory Finance, Public Utility Reports, Inc., 2021, at 481-482. ("Morin")

market-based DCF model will produce the total annual dollar return expected by investors only when market and book values are equal, which is, again, a rare and unlikely situation.

Market values can diverge from book values for a myriad of reasons including, but not limited to, EPS and DPS expectations, merger/acquisition expectations, the rising interest rate environment, etc. As noted by Phillips:

> Many question the assumption that market price should equal book value, believing that "the earnings of utilities should be sufficiently high to achieve market-to-book ratios which are consistent with those prevailing for stocks of unregulated companies."[10]

In addition, Bonbright states:

> In the first place, commissions cannot forecast, except within wide limits, the effect their rate orders will have on the market prices of the stocks of the companies they regulate. In the second place, *whatever the initial market prices may be, they are sure to change not only with the changing prospects for earnings, but with the changing outlook of an inherently volatile stock market.* In short, market prices are beyond the control, though not beyond the influence of rate regulation. Moreover, even if a commission did possess the power of control, any attempt to exercise it ... would result in harmful, uneconomic shifts in public utility rate levels. (italics added)[11]

Q. Can the under- or overstatement of investors' required rate of return by the DCF model be demonstrated mathematically?

A. Yes. The under- or overstatement of the investor required rate of return on the market by the DCF model is demonstrated mathematically in a hypothetical example on page 2 of Schedule DWD-2. Column [1] represents a M/B ratio of

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[10] Charles F. Phillips, The Regulation of Public Utilities, Public Utilities Reports, Inc., 1993, at 395.

[11] James C. Bonbright, Albert L. Danielsen and David R. Kamerschen, Principles of Public Utility Rates, Public Utilities Reports, Inc., 1988, at 334.

100% (market and book value of equity is $30.00 per share). The DCF cost rate of 10.00% is comprised of a 3.00% dividend yield and 7.00% growth rate. The total return expected by investors is $3.00 ($0.90 dividends, $2.10 capital appreciation). When M/B ratios are not equal to 100%, the DCF model mis-specifies the investor expected return. As shown in Column [2], Line No. 7, using the same market value as Column [1] ($30.00) and a book value per share of $15.00 (a M/B ratio of 200%), the investor would only receive a return on book value of $1.50 ($15.00 * 10.00% investor-expected return). The $1.50 is broken down into $0.90 in dividends ($30.00 market price * 3.00% dividend yield) and $0.60 in capital appreciation. Since investor's expectations are based on market values, the capital appreciation return is 2.00% ($0.60 / $30.00), which is 5.00% less than the investor-expected return of 7.00% (the growth term in the DCF model). Conversely, as shown in Column [3], using the same market value of $30.00 and a book value per share of $37.50 (a M/B ratio of 80%), the investor would receive a return on book value of $3.75 ($37.50 * 10.00% investor-expected return) The $3.75 is broken down into $0.90 in dividends ($30.00 market price * 3.00% dividend yield) and $2.85 in capital appreciation. Since investor's expectations are based on market values, the capital appreciation return is 9.50% ($2.85 / $30.00), which is 2.50% more than the investor-expected return of 7.00% (the growth term in the DCF model).

Stated simply, the DCF model either understates or overstates investors' required cost of common equity capital when market values exceed or are less than their underlying book values. In this instance, the DCF model results for the Utility Proxy Group is a clear outlier compared to my other cost of common equity model

results. Because of this, multiple cost of common equity models must be used for one to derive a more reliable estimate of the cost of common equity for a company.

B. The Risk Premium Model

Q. Please describe the theoretical basis of the RPM.

A. The RPM is based on the fundamental financial principle of risk and return; namely, that investors require greater returns for bearing greater risk. The RPM recognizes that common equity capital has greater investment risk than debt capital, as common equity shareholders are behind debt holders in any claim on a company's assets and earnings. As a result, investors require higher returns from common stocks than from bonds to compensate them for bearing the additional risk.

While it is possible to directly observe bond returns and yields, investors' required common equity returns cannot be directly determined or observed. According to RPM theory, one can estimate a common equity risk premium over bonds (either historically or prospectively), and use that premium to derive a cost rate of common equity. The cost of common equity equals the expected cost rate for long-term debt capital, plus a risk premium over that cost rate, to compensate common shareholders for the added risk of being unsecured and last-in-line for any claim on the corporation's assets and earnings upon liquidation.

Q. Please explain how you derived your indicated cost of common equity based on the RPM.

A. To derive my indicated cost of common equity under the RPM, I used two risk premium methods. The first method was the Predictive Risk Premium Model ("PRPM") and the second method was a risk premium model using a total market

approach. The PRPM estimates the risk-return relationship directly, while the total market approach indirectly derives a risk premium by using known metrics as a proxy for risk.

1. Predictive Risk Premium Model

Q. Please explain the PRPM.

A. The PRPM, published in the *Journal of Regulatory Economics,*[12] was developed from the work of Robert F. Engle, who shared the Nobel Prize in Economics in 2003 "for methods of analyzing economic time series with time-varying volatility" or ARCH.[13] Engle found that volatility changes over time and is related from one period to the next, especially in financial markets. Engle discovered that volatility of prices and returns clusters over time and is therefore highly predictable and can be used to predict future levels of risk and risk premiums. That is, historical volatility can be used to predict future volatility, which then can be translated to a predicted equity risk premium.

Q. How does the PRPM estimate the investor required return?

A. The PRPM estimates the risk-return relationship directly, as the predicted equity risk premium is generated by predicting volatility or risk. The PRPM is not based on an estimate of investor behavior, but rather on an evaluation of the results of that behavior (i.e., the variance of historical equity risk premiums).

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[12] Pauline M. Ahern, Frank J. Hanley and Richard A. Michelfelder, Ph.D. "A New Approach for Estimating the Equity Risk Premium for Public Utilities", The Journal of Regulatory Economics (December 2011), 40:261-278.

[13] Autoregressive conditional heteroscedasticity; *See also,* www.nobelprize.org.

Q. Please explain your application of the PRPM.

A. The inputs to the model are the historical returns on the common shares of each Utility Proxy Group company minus the historical monthly yield on long-term U.S. Treasury securities through December 2022. Using a generalized form of ARCH, known as GARCH, I calculated each Utility Proxy Group company's projected equity risk premium using Eviews© statistical software. When the GARCH model is applied to the historical return data, it produces a predicted GARCH variance series[14] and a GARCH coefficient[15]. Multiplying the predicted monthly variance by the GARCH coefficient and then annualizing it[16] produces the predicted annual equity risk premium. I then added the forecasted 30-year U.S. Treasury bond yield of 3.91%[17] to each company's PRPM-derived equity risk premium to arrive at an indicated cost of common equity. The 30-year U.S. Treasury bond yield is a consensus forecast derived from *Blue Chip*.[18]

Q. What are the results of the PRPM as applied to the utility proxy group?

A. The mean PRPM indicated common equity cost rate for the Utility Proxy Group is 11.99%, the median is 11.90%, and the average of the two is 11.95%. Consistent with my reliance on the average of the median and mean results of the DCF models, I relied on the average of the mean and median results of the Utility Proxy Group PRPM to calculate a cost of common equity rate of 11.95%.

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14 Illustrated on Columns 1 and 2, page 2 of Schedule DWD-3.
15 Illustrated on Column 4, page 2 of Schedule DWD-3.
16 Annualized Return = (1 + Monthly Return) ^12 - 1
17 *See*, Column 6, page 2 of Schedule DWD-3.
18 *Blue Chip Financial Forecasts ("Blue Chip")*, January 1, 2023 at 2, and December 2, 2022 at 14.

Q. Please describe your selection of a risk-free rate of return.

A. As shown in Schedules DWD-3 and DWD-4, the risk-free rate adopted for applications of the RPM and CAPM is 3.91%. This risk-free rate is based on the average of the *Blue Chip* consensus forecast of the expected yields on 30-year U.S. Treasury bonds for the six quarters ending with the second calendar quarter of 2024, and long-term projections for the years 2024 to 2028 and 2029 to 2033.

Q. Why do you use the projected 30-year treasury yield in your analyses?

A. The yield on long-term U.S. Treasury bonds is almost risk-free and its term is consistent with the long-term cost of capital to public utilities measured by the yields on Moody's A2-rated public utility bonds; the long-term investment horizon inherent in utilities' common stocks; and the long-term life of the jurisdictional rate base to which the allowed fair rate of return (i.e., cost of capital) will be applied. In contrast, short-term U.S. Treasury yields are more volatile and largely a function of Federal Reserve monetary policy.

More specifically, the term of the risk-free rate used for cost of capital purposes should match the life (or duration) of the underlying investment (i.e., perpetuity). As noted by Morningstar:

> The traditional thinking regarding the time horizon of the chosen Treasury security is that it should match the time horizon of whatever is being valued. When valuing a business that is being treated as a going concern, the appropriate Treasury yield should be that of a long-term Treasury bond. Note that the horizon is a function of the investment, not the investor. If an investor plans to hold stock in a company for only five years, the yield on a five-year Treasury note would not be appropriate since the company will continue to exist beyond those five years.[19]

[19] Morningstar, Inc., 2013 Ibbotson Stocks, Bonds, Bills and Inflation Valuation Yearbook, at 44.

Morin also confirms this when he states:

> [b]ecause common stock is a long-term investment and because the cash flows to investors in the form of dividends last indefinitely, the yield on very long-term government bonds, namely, the yield on 30-year Treasury bonds, is the best measure of the risk-free rate for use in the CAPM and Risk Premium methods (footnote omitted)… The expected common stock return is based on long-term cash flows, regardless of an individual's holding time period.[20]

Pratt and Grabowski recommend a similar approach to selecting the risk-free rate: "[i]n theory, when determining the risk-free rate and the matching ERP you should be matching the risk-free security and the ERP with the period in which the investment cash flows are expected."[21]

As a practical matter, equity securities represent a perpetual claim on cash flows; 30-year Treasury bonds are the longest-maturity securities available to approximate that perpetual claim. Thus, the use of a 30-year Treasury bond yield is a more appropriate risk-free rate as it more accurately reflects the life of the assets it finances.

2. Total Market Approach Risk Premium Model

Q. Please explain the total market approach RPM.

A. The total market approach RPM adds a prospective public utility bond yield to an average of: (1) an equity risk premium that is derived from a beta-adjusted total market equity risk premium, (2) an equity risk premium based on the S&P Utilities Index, and (3) an equity risk premium based on authorized ROEs for electric utilities.

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[20] Morin, at 169.

[21] Shannon Pratt and Roger Grabowski, Cost of Capital: Applications and Examples, 3rd Ed. (Hoboken, NJ: John Wiley & Sons, Inc., 2008), at 92. "ERP" is the Equity Risk Premium.

Q. Please explain how you determined the expected bond yield applicable to the utility proxy group.

A. The first step in the total market approach RPM analysis is to determine the expected bond yield. Because both ratemaking and the cost of capital, including the common equity cost rate, are prospective in nature, a prospective yield on similarly-rated long-term debt is essential. Because I am unaware of any publication that provides forecasted public utility bond yields, I relied on a consensus forecast of about 50 economists of the expected yield on Aaa-rated corporate bonds for the six calendar quarters ending with the second calendar quarter of 2024, and *Blue Chip's* long-term projections for 2024 to 2028, and 2029 to 2033. As shown on line 1, page 3 of Schedule DWD-3, the average expected yield on Moody's Aaa-rated corporate bonds is 5.05%.

Because that 5.05% estimate represents a corporate bond yield and not a utility specific bond yield, I adjusted the expected Aaa-rated corporate bond yield to an equivalent A2-rated public utility bond yield. That resulted in an upward adjustment of 0.83%, which represents a recent spread between Aaa-rated corporate bonds and A2-rated public utility bonds.[22] Adding that recent 0.83% spread to the expected Aaa-rated corporate bond yield of 5.05% results in an expected A2-rated public utility bond yield of 5.88%.

I then reviewed the average credit rating for the Utility Proxy Group from Moody's to determine if an adjustment to the estimated A2-rated public utility bond was necessary. Since the Utility Proxy Group's average Moody's long-term issuer

[22] As shown on line 2 and explained in note 2, page 3 of Schedule DWD-3.

rating is Baa1, another adjustment to the expected A2-rated public utility bond is needed to reflect the difference in bond ratings. An upward adjustment of 0.20%, which represents two-thirds of a recent spread between A2-rated and Baa2-rated public utility bond yields, is necessary to make the A2-rated prospective bond yield applicable to an Baa1-rated public utility bond.[23] Adding the 0.20% to the 5.88% prospective A2-rated public utility bond yield results in a 6.08% expected bond yield applicable to the Utility Proxy Group.

Table 4: Summary of the Calculation of the Utility Proxy Group Projected Bond Yield[24]

Prospective Yield on Moody's Aaa-Rated Corporate Bonds (*Blue Chip)*	5.05%
Adjustment to Reflect Yield Spread Between Moody's Aaa-Rated Corporate Bonds and Moody's A2-Rated Utility Bonds	0.83%
Adjustment to Reflect the Utility Proxy Group's Average Moody's Bond Rating of Baa1	0.20%
Prospective Bond Yield Applicable to the Utility Proxy Group	6.08%

To develop the total market approach RPM estimate of the appropriate return on equity, this prospective bond yield is then added to the average of the three different equity risk premiums, which I now discuss, in turn.

a. Beta-Derived Equity Risk Premium

Q. Please explain how the beta-derived equity risk premium is determined.

A. The components of the beta-derived risk premium model are: (1) an expected market equity risk premium over corporate bonds, and (2) the beta. The derivation of the beta-derived equity risk premium that I applied to the Utility Proxy Group is

[23] As shown on line 4 and explained in note 3, page 3 of Schedule DWD-3.
[24] As shown on page 3 of Schedule DWD-3.

shown on lines 1 through 9, page 8 of Schedule DWD-3. The total beta-derived equity risk premium I applied is based on an average of three historical market data-based equity risk premiums, two *Value Line*-based equity risk premiums and a Bloomberg-based equity risk premium. Each of these is described below.

Q. How did you derive a market equity risk premium based on long-term historical data?

A. To derive a historical market equity risk premium, I used the most recent holding period returns for the large company common stocks from the Stocks, Bonds, Bills, and Inflation ("SBBI") Yearbook 2022 ("SBBI - 2022")[25] less the average historical yield on Moody's Aaa/Aa2-rated corporate bonds for the period 1928 to 2021. Using holding period returns over a very long time is appropriate because it is consistent with the long-term investment horizon presumed by investing in a going concern, i.e., a company expected to operate in perpetuity.

SBBI's long-term arithmetic mean monthly total return rate on large company common stocks was 12.11% and the long-term arithmetic mean monthly yield on Moody's Aaa/Aa2-rated corporate bonds was 5.98%.[26] As shown on line 1, page 8 of Schedule DWD-3, subtracting the mean monthly bond yield from the total return on large company stocks results in a long-term historical equity risk premium of 6.13%.

I used the arithmetic mean monthly total return rates for the large company stocks and yields (income returns) for the Moody's Aaa/Aa2 corporate bonds,

[25] *See*, SBBI-2022 Appendix A Tables: Morningstar Stocks, Bonds, Bills, & Inflation 1926-2021.
[26] As explained in note 1, page 9 of Schedule DWD-3.

because they are appropriate for the purpose of estimating the cost of capital as noted in SBBI - 2022.[27] Using the arithmetic mean return rates and yields is appropriate because historical total returns and equity risk premiums provide insight into the variance and standard deviation of returns needed by investors in estimating future risk when making a current investment. If investors relied on the geometric mean of historical equity risk premiums, they would have no insight into the potential variance of future returns, because the geometric mean relates the change over many periods to a constant rate of change, thereby obviating the year-to-year fluctuations, or variance, which is critical to risk analysis.

Q. Please explain the derivation of the regression-based market equity risk premium.

A. To derive the regression-based market equity risk premium of 7.26% shown on line 2, page 8 of Schedule DWD-3, I used the same monthly annualized total returns on large company common stocks relative to the monthly annualized yields on Moody's Aaa/Aa2-rated corporate bonds as mentioned above. I modeled the relationship between interest rates and the market equity risk premium using the observed monthly market equity risk premium as the dependent variable, and the monthly yield on Moody's Aaa/Aa2-rated corporate bonds as the independent variable. I then used a linear Ordinary Least Squares ("OLS") regression, in which the market equity risk premium is expressed as a function of the Moody's Aaa/Aa2-rated corporate bonds yield:

$$RP = \alpha + \beta\ (R_{Aaa/Aa2})$$

[27] SBBI - 2022, at page 201.

Q. Please explain the derivation of the PRPM equity risk premium.

A. I used the same PRPM approach described above to the PRPM equity risk premium. The inputs to the model are the historical monthly returns on large company common stocks minus the monthly yields on Moody's Aaa/Aa2-rated corporate bonds during the period from January 1928 through December 2022.[28] Using the previously discussed generalized form of ARCH, known as GARCH, the projected equity risk premium is determined using Eviews© statistical software. The resulting PRPM predicted a market equity risk premium of 9.76%.[29]

Q. Please explain the derivation of a projected equity risk premium based on *value line* data for your rpm analysis.

A. As noted above, because both ratemaking and the cost of capital are prospective, a prospective market equity risk premium is needed. The derivation of the forecasted or prospective market equity risk premium can be found in note 4, page 8 of Schedule DWD-3. Consistent with my calculation of the dividend yield component in my DCF analysis, this prospective market equity risk premium is derived from an average of the three- to five-year median market price appreciation potential by *Value Line* for the 13 weeks ended December 30, 2022, plus an average of the median estimated dividend yield for the common stocks of the 1,700 firms covered in *Value Line*'s Standard Edition.[30]

[28] Data from January 1926 to December 2021 is from SBBI - 2022. Data from January 2022 to December 2022 is from Bloomberg.

[29] Shown on line 3, page 8 of Schedule DWD-3.

[30] As explained in detail in note 1, page 2 of Schedule DWD-3.

The average median expected price appreciation is 71%, which translates to a 14.35% annual appreciation, and, when added to the average of *Value Line's* median expected dividend yields of 2.23%, equates to a forecasted annual total return rate on the market of 16.58%. The forecasted Moody's Aaa-rated corporate bond yield of 5.05% is deducted from the total market return of 16.58%, resulting in an equity risk premium of 11.53%, as shown on line 4, page 8 of Schedule DWD-3.

Q. Please explain the derivation of an equity risk premium based on the S&P 500 companies.

A. Using data from *Value Line*, I calculated an expected total return on the S&P 500 companies using expected dividend yields and long-term growth estimates as a proxy for capital appreciation. The expected total return for the S&P 500 is 15.67%. Subtracting the prospective yield on Moody's Aaa-rated corporate bonds of 5.05% results in a 10.62% projected equity risk premium.

Q. Please explain the derivation of an equity risk premium based on Bloomberg data.

A. Using data from Bloomberg, I calculated an expected total return on the S&P 500 using expected dividend yields and long-term growth estimates as a proxy for capital appreciation, identical to the method described above. The expected total return for the S&P 500 is 11.06%. Subtracting the prospective yield on Moody's Aaa-rated corporate bonds of 5.05% results in a 6.01% projected equity risk premium.

Q. What is your conclusion of a beta-derived equity risk premium for use in your RPM analysis?

A. I gave equal weight to all six equity risk premiums based on each source - historical, *Value Line*, and Bloomberg - in arriving at an 8.55% equity risk premium.

Table 5: Summary of the Calculation of the Equity Risk Premium Using Total Market Returns[31]

Historical Spread Between Total Returns of Large Stocks and Aaa and Aa2-Rated Corporate Bond Yields (1928 – 2021)	6.13%
Regression Analysis on Historical Data	7.26%
PRPM Analysis on Historical Data	9.76%
Prospective Equity Risk Premium using Total Market Returns from *Value Line* Summary & Index less Projected Aaa Corporate Bond Yields	11.53%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from *Value Line* for the S&P 500 less Projected Aaa Corporate Bond Yields	10.62%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from Bloomberg Professional Services for the S&P 500 less Projected Aaa Corporate Bond Yields	6.01%
Average	8.55%

After calculating the average market equity risk premium of 8.55%, I adjusted it by beta to account for the risk of the Utility Proxy Group. As discussed below, beta is a meaningful measure of prospective relative risk to the market as a whole, and is a logical way to allocate a company's, or proxy group's, share of the market's total equity risk premium relative to corporate bond yields. As shown on page 1 of Schedule DWD-4, the average of the mean and median beta for the Utility Proxy Group is 0.78. Multiplying the 0.78 average beta by the market equity risk

[31] As shown on page 8 of Schedule DWD-3.

premium of 8.55% results in a beta-adjusted equity risk premium for the Utility Proxy Group of 6.67%.

b. S&P Utility Index Derived Equity Risk Premium

Q. How did you derive the equity risk premium based on the S&P Utility Index and Moody's a2-rated public utility bonds?

A. I estimated three equity risk premiums based on S&P Utility Index holding period returns, and two equity risk premiums based on the expected returns of the S&P Utilities Index, using *Value Line* and Bloomberg data, respectively. Turning first to the S&P Utility Index holding period returns, I derived a long-term monthly arithmetic mean equity risk premium between the S&P Utility Index total returns of 10.74% and monthly Moody's A2-rated public utility bond yields of 6.46% from 1928 to 2021 to arrive at an equity risk premium of 4.28%.[32] I then used the same historical data to derive an equity risk premium of 4.80% based on a regression of the monthly equity risk premiums. The final S&P Utility Index holding period equity risk premium involved applying the PRPM using the historical monthly equity risk premiums from January 1928 to December 2022 to arrive at a PRPM-derived equity risk premium of 5.56% for the S&P Utility Index.

I then derived expected total returns on the S&P Utilities Index of 9.50% and 9.20% using data from *Value Line* and Bloomberg, respectively, and subtracted the prospective Moody's A2-rated public utility bond yield of 5.88%[33], which resulted in equity risk premiums of 3.62% and 3.32%, respectively. As with the market equity risk premiums, I averaged each risk premium based on each source

[32] As shown on line 1, page 12 of Schedule DWD-3.
[33] Derived on line 3, page 3 of Schedule DWD-3.

(i.e., historical, *Value Line*, and Bloomberg) to arrive at my utility-specific equity risk premium of 4.32%.

Table 6: Summary of the Calculation of the Equity Risk Premium Using S&P Utility Index Holding Returns[34]

Historical Spread Between Total Returns of the S&P Utilities Index and A2-Rated Utility Bond Yields (1928 – 2021)	4.28%
Regression Analysis on Historical Data	4.80%
PRPM Analysis on Historical Data	5.56%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from *Value Line* for the S&P Utilities Index less Projected A2 Utility Bond Yields	3.62%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from Bloomberg Professional Services for the S&P Utilities Index less Projected A2 Utility Bond Yields	3.32%
Average	4.32%

c. Authorized Return Derived Equity Risk Premium

Q. How do you derive an equity risk premium of 4.77% based on authorized ROEs for electric utilities?

A. The equity risk premium of 4.77% shown on page 13 of Schedule DWD-3 is the result of a regression analysis based on regulatory awarded ROEs related to the yields on Moody's A2-rated public utility bonds. Page 13 of Schedule DWD-3 contains the graphical results of a regression analysis of 1,207 rate cases for electric utilities which were fully litigated during the period from January 1, 1980 through December 30, 2022. It shows the implicit equity risk premium relative to the yields on A2-rated public utility bonds immediately prior to the issuance of each regulatory decision.

[34] As shown on page 12 of Schedule DWD-3.

It is readily discernible that there is an inverse relationship between the yield on A2-rated public utility bonds and equity risk premiums. In other words, as interest rates decline, the equity risk premium rises and vice versa, a result consistent with financial literature on the subject.[35] I used the regression results to estimate the equity risk premium applicable to the projected yield on Moody's A2-rated public utility bonds. Given the expected A2-rated utility bond yield of 5.88%, it can be calculated that the indicated equity risk premium applicable to that bond yield is 4.77%, which is shown on line 3, page 7 of Schedule DWD-3.

Q. What is your conclusion of an equity risk premium for use in your total market approach RPM analysis?

A. The equity risk premium I apply to the Utility Proxy Group is 5.25%, which is the average of the beta-adjusted equity risk premium for the Utility Proxy Group, the S&P Utilities Index, and the authorized return utility equity risk premiums of 6.67%, 4.32%, and 4.77%, respectively.[36]

Q. What is the indicated RPM common equity cost rate based on the total market approach?

A. As shown on line 7, page 3 of Schedule DWD-3 and shown on Table 7, below, I calculated a common equity cost rate of 11.33% for the Utility Proxy Group based on the total market approach RPM.

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[35] *See*, e.g., Robert S. Harris and Felicia C. Marston, *The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts*, Journal of Applied Finance, Vol. 11, No. 1, 2001, at pages 11 to 12; Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management, Spring 1985, at pages 33 to 45.

[36] As shown on page 7 of Schedule DWD-3.

Table 7: Summary of the Total Market Return Risk Premium Model[37]

Prospective Moody's Baa1-Rated Utility Bond Applicable to the Utility Proxy Group	6.08%
Prospective Equity Risk Premium	5.25%
Indicated Cost of Common Equity	11.33%

Q. What are the results of your application of the PRPM and the total market approach RPM?

A. As shown on page 1 of Schedule DWD-3, the indicated RPM-derived common equity cost rate is 11.64%, which gives equal weight to the PRPM (11.95%) and the adjusted-market approach results (11.33%).

C. The Capital Asset Pricing Model

Q. Please explain the theoretical basis of the CAPM.

A. CAPM theory defines risk as the co-variability of a security's returns with the market's returns as measured by beta (β). A beta less than 1.0 indicates lower variability than the market as a whole, while a beta greater than 1.0 indicates greater variability than the market.

The CAPM assumes that all non-market or unsystematic risk can be eliminated through diversification. The risk that cannot be eliminated through diversification is called market, or systematic, risk. In addition, the CAPM presumes that investors only require compensation for systematic risk, which is the result of macroeconomic and other events that affect the returns on all assets. The model is applied by adding a risk-free rate of return to a market risk premium, which is adjusted proportionately to reflect the systematic risk of the individual security

[37] As shown on page 3 of Schedule DWD-3.

relative to the total market as measured by the beta. The traditional CAPM model is expressed as:

$$R_s = R_f + \beta (R_m - R_f)$$

Where:
- R_s = Return rate on the common stock
- R_f = Risk-free rate of return
- R_m = Return rate on the market as a whole
- β = Adjusted beta (volatility of the security relative to the market as a whole)

Numerous tests of the CAPM have measured the extent to which security returns and beta are related as predicted by the CAPM, confirming its validity. The empirical CAPM ("ECAPM") reflects the reality that while the results of these tests support the notion that the beta is related to security returns, the empirical Security Market Line ("SML") described by the CAPM formula is not as steeply sloped as the predicted SML.[38]

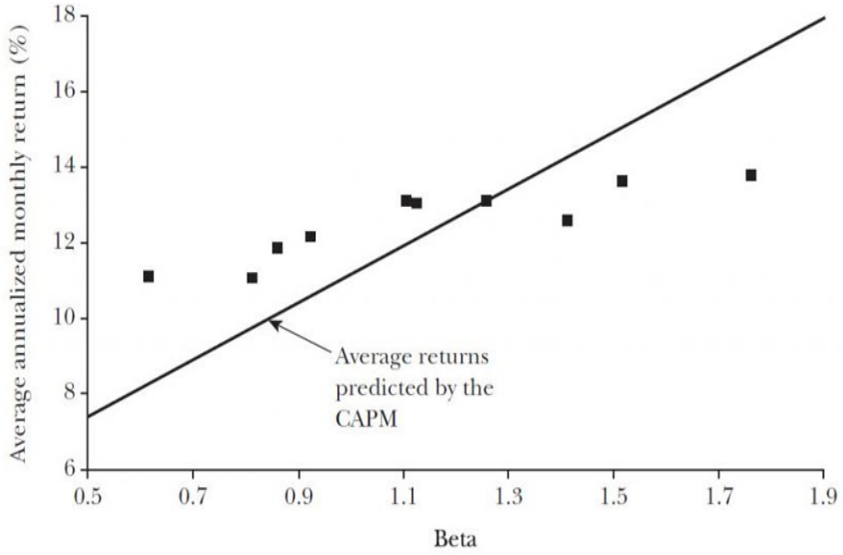
The ECAPM reflects this empirical reality. Fama and French clearly state regarding Figure 2, below, that "[t]he returns on the low beta portfolios are too high, and the returns on the high beta portfolios are too low."[39]

[38] Morin, at page 220.

[39] Eugene F. Fama and Kenneth R. French, "The Capital Asset Pricing Model: Theory and Evidence", *Journal of Economic Perspectives*, Vol. 18, No. 3, Summer 2004 at 33 "Fama & French".

Figure 2 http://pubs.aeaweb.org/doi/pdfplus/10.1257/0895330042162430

Average Annualized Monthly Return versus Beta for Value Weight Portfolios Formed on Prior Beta, 1928–2003



In addition, Morin observes that while the results of these tests support the notion that beta is related to security returns, the empirical SML described by the CAPM formula is not as steeply sloped as the predicted SML. Morin states:

> With few exceptions, the empirical studies agree that … low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted.[40]
>
> * * *
>
> Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:
>
> $$K = R_F + x\,\beta(R_M - R_F) + (1-x)\,\beta(R_M - R_F)$$
>
> where x is a fraction to be determined empirically. The value of x that best explains the observed relationship [is] Return = 0.0829 + 0.0520 β is between 0.25 and 0.30. If x = 0.25, the equation becomes:
>
> $$K = R_F + 0.25(R_M - R_F) + 0.75\,\beta(R_M - R_F)$$[41]

[40] Morin, at 207.

[41] Morin, at 221.

Fama and French provide similar support for the ECAPM when they state:

> The early tests firmly reject the Sharpe-Lintner version of the CAPM. There is a positive relation between beta and average return, but it is too 'flat.'… The regressions consistently find that the intercept is greater than the average risk-free rate… and the coefficient on beta is less than the average excess market return… This is true in the early tests… as well as in more recent cross-section regressions tests, like Fama and French (1992).[42]

Finally, Fama and French further note:

> Confirming earlier evidence, the relation between beta and average return for the ten portfolios is much flatter than the Sharpe-Linter CAPM predicts. The returns on low beta portfolios are too high, and the returns on the high beta portfolios are too low. For example, the predicted return on the portfolio with the lowest beta is 8.3 percent per year; the actual return as 11.1 percent. The predicted return on the portfolio with the t beta is 16.8 percent per year; the actual is 13.7 percent.[43]

Clearly, the justification from Morin, Fama, and French, along with their reviews of other academic research on the CAPM, validate the use of the ECAPM. In view of theory and practical research, I have applied both the traditional CAPM and the ECAPM to the companies in the Utility Proxy Group and averaged the results.

Q. What beta coefficients did you use in your CAPM analysis?

A. For the beta in my CAPM analysis, I considered two sources: *Value Line* and Bloomberg Professional Services. While both of those services adjust their calculated (or "raw") betas to reflect the tendency of beta to regress to the market mean of 1.00, *Value Line* calculates beta over a five-year period, while Bloomberg calculates it over a two-year period.

[42] Fama & French, at 32.
[43] Fama & French, at 33.

Q. Please describe your selection of a risk-free rate of return.

A. As described previously, the risk-free rate adopted for both applications of the CAPM is 3.91%. This risk-free rate is based on the average of the *Blue Chip* consensus forecast of the expected yields on 30-year U.S. Treasury bonds for the six quarters ending with the second calendar quarter of 2024, and long-term projections for the years 2024 to 2028 and 2029 to 2033.

Q. Please explain the estimation of the expected risk premium for the market used in your CAPM analyses.

A. The basis of the market risk premium is explained in detail in note 1 on Schedule DWD-4. As discussed above, the market risk premium is derived from an average of three historical data-based market risk premiums, two *Value Line* data-based market risk premiums, and one Bloomberg data-based market risk premium.

The long-term income return on U.S. Government securities of 5.02% was deducted from the SBBI - 2022 monthly historical total market return of 12.37%, which results in an historical market equity risk premium of 7.35%.[44] I applied a linear OLS regression to the monthly annualized historical returns on the S&P 500 relative to historical yields on long-term U.S. Government securities from SBBI - 2022. That regression analysis yielded a market equity risk premium of 8.71%. The PRPM market equity risk premium is 10.86% and is derived using the PRPM relative to the yields on long-term U.S. Treasury securities from January 1926 through December 2022.

[44] SBBI - 2022, at Appendix A-1 (1) through A-1 (3) and Appendix A-7 (19) through A-7 (21).

The *Value Line*-derived forecasted total market equity risk premium is derived by deducting the forecasted risk-free rate of 3.91%, discussed above, from the *Value Line* projected total annual market return of 16.58%, resulting in a forecasted total market equity risk premium of 12.67%. The S&P 500 projected market equity risk premium using *Value Line* data is derived by subtracting the projected risk-free rate of 3.91% from the projected total return of the S&P 500 of 15.67%. The resulting market equity risk premium is 11.76%.

The S&P 500 projected market equity risk premium using Bloomberg data is derived by subtracting the projected risk-free rate of 3.91% from the projected total return of the S&P 500 of 11.06%. The resulting market equity risk premium is 7.15%. These six measures, when averaged, result in an average total market equity risk premium of 9.75%.

Table 8: Summary of the Calculation of the Market Risk Premium for Use in the CAPM[45]

Historical Spread Between Total Returns of Large Stocks and Long-Term Government Bond Yields (1926 – 2021)	7.35%
Regression Analysis on Historical Data	8.71%
PRPM Analysis on Historical Data	10.86%
Prospective Equity Risk Premium using Total Market Returns from *Value Line* Summary & Index less Projected 30-Year Treasury Bond Yields	12.67%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from *Value Line* for the S&P 500 less Projected 30-Year Treasury Bond Yields	11.76%
Prospective Equity Risk Premium using Measures of Capital Appreciation and Income Returns from Bloomberg Professional Services for the S&P 500 less Projected 30-Year Treasury Bond Yields	7.15%
Average	9.75%

[45] As shown on page 2 of Schedule DWD-4.

Q. What are the results of your application of the traditional and empirical CAPM to the utility proxy group?

A. As shown on page 1 of Schedule DWD-4, the mean result of my CAPM/ECAPM analyses is 11.80%, the median is 11.78%, and the average of the two is 11.79%. Consistent with my reliance on the average of mean and median DCF results discussed above, the indicated common equity cost rate using the CAPM/ECAPM is 11.79%.

D. Common Equity Cost Rates for a Proxy Group of Domestic, Non-Price Regulated Companies Based on the DCF, RPM, and CAPM

Q. Why do you also consider a proxy group of domestic, non-price regulated companies?

A. Although I am not an attorney, my interpretation of the *Hope* and *Bluefield* cases is that they did not specify that comparable risk companies had to be utilities. Since the purpose of rate regulation is to be a substitute for marketplace competition, non-price regulated firms operating in the competitive marketplace make an excellent proxy if they are comparable in total risk to the Utility Proxy Group being used to estimate the cost of common equity. The selection of such domestic, non-price regulated competitive firms theoretically and empirically results in a proxy group which is comparable in total risk to the Utility Proxy Group, since all of these companies compete for capital in the exact same markets.

Q. How did you select non-price regulated companies that are comparable in total risk to the utility proxy group?

A. In order to select a proxy group of domestic, non-price regulated companies similar in total risk to the Utility Proxy Group, I relied on the betas and related statistics

derived from *Value Line* regression analyses of weekly market prices over the most recent 260 weeks (i.e., five years). These selection criteria resulted in a proxy group of 50 domestic, non-price regulated firms comparable in total risk to the Utility Proxy Group. Total risk is the sum of non-diversifiable market risk and diversifiable company-specific risks. The criteria used in selecting the domestic, non-price regulated firms was:

(i) They must be covered by *Value Line Investment Survey* (Standard Edition);

(ii) They must be domestic, non-price regulated companies, i.e., not utilities;

(iii) Their betas must lie within plus or minus two standard deviations of the average unadjusted betas of the Utility Proxy Group; and

(iv) The residual standard errors of the *Value Line* regressions which gave rise to the unadjusted betas must lie within plus or minus two standard deviations of the average residual standard error of the Utility Proxy Group.

Betas measure market, or systematic, risk, which is not diversifiable. The residual standard errors of the regressions measure each firm's company-specific, diversifiable risk. Companies that have similar betas and similar residual standard errors resulting from the same regression analyses have similar total investment risk.

Q. Have you prepared a schedule which shows the data from which you selected the 50 domestic, non-price regulated companies that are comparable in total risk to the utility proxy group?

A. Yes, the basis of my selection and both proxy groups' regression statistics are shown in Schedule DWD-5.

Q. Did you calculate common equity cost rates using the DCF model, RPM, and CAPM for the non-price regulated proxy group?

A. Yes. Because the DCF model, RPM, and CAPM have been applied in an identical manner as described above, I will not repeat the details of the rationale and application of each model. One exception is in the application of the RPM, where I did not use public utility-specific equity risk premiums, nor did I apply the PRPM to the individual non-price regulated companies.

Page 2 of Schedule DWD-6 derives the Constant Growth DCF model common equity cost rate. As shown, the indicated common equity cost rate is 11.72%.

Pages 3 through 5 of Schedule DWD-6 contain the data and calculations that support the 13.40% RPM common equity cost rate. As shown on line 1, page 3 of Schedule DWD-6, the consensus prospective yield on Moody's Baa-rated corporate bonds for the six quarters ending in the second quarter of 2024, and for the years 2024 to 2028 and 2029 to 2033, is 6.05%.[46] Since the Non-Price Regulated Proxy Group has an average Moody's long-term issuer rating of Baa1, a downward adjustment of 0.17% to the projected Baa2-rated corporate bond yield is necessary to reflect a difference in ratings which results in a projected Baa1-rated corporate bond yield of 5.88% for the Non-Regulated Proxy group.

When the beta-adjusted risk premium of 7.52%[47] relative to the Non-Price Regulated Proxy Group is added to the prospective Baa1-rated corporate bond yield of 5.88%, the indicated RPM common equity cost rate is 13.40%.

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[46] *Blue Chip Financial Forecasts*, January 1, 2023, at 2 and December 2, 2022 at.

[47] Derived on page 5 of Schedule DWD-6.

Page 6 of Schedule DWD-6 contains the inputs and calculations that support my indicated CAPM/ECAPM common equity cost rate of 12.59%.

Q. How is the cost rate of common equity based on the non-price regulated proxy group comparable in total risk to the utility proxy group?

A. As shown on page 1 of Schedule DWD-6, the results of the common equity models applied to the Non-Price Regulated Proxy Group -- which group is comparable in total risk to the Utility Proxy Group -- are as follows: 11.72% (DCF), 13.40% (RPM), and 12.59% (CAPM). The average of the mean and median of these models is 12.58%, which I used as the indicated common equity cost rates for the Non-Price Regulated Proxy Group.

VI. CONCLUSION OF COMMON EQUITY COST RATE BEFORE ADJUSTMENTS

Q. What is the indicated common equity cost rate before adjustments?

A. By applying multiple cost of common equity models to the Utility Proxy Group and the Non-Price Regulated Proxy Group, the indicated range of common equity cost rates attributable to the Utility Proxy Group before any relative risk adjustments is between 10.04% and 11.04%. I used multiple cost of common equity models as primary tools in arriving at my recommended common equity cost rate, because each of these models is theoretically sound and available to investors, and because no single model is so inherently precise that it can be relied on to the exclusion of other theoretically sound models. Using multiple models adds reliability to the estimated common equity cost rate, with the prudence of using multiple cost of

common equity models supported in both the financial literature and regulatory precedent.

Based on these common equity cost rate results, I conclude that a range of common equity cost rates between 10.04% and 11.04% is reasonable and appropriate before any adjustments for relative risk differences between JCP&L and the Utility Proxy Group are made.

VII. ADJUSTMENTS TO THE COMMON EQUITY COST RATE

A. Size Adjustment

Q. Does JCP&L's smaller size relative to the utility proxy group companies increase its business risk?

A. Yes. JCP&L's smaller size relative to the Utility Proxy Group companies indicates greater relative business risk for the Company because, all else being equal, size has a material bearing on risk.

Size affects business risk because smaller companies generally are less able to cope with significant events that affect sales, revenues, and earnings. For example, smaller companies face more risk exposure to business cycles and economic conditions, both nationally and locally. Additionally, the loss of revenues from a few larger customers would have a greater effect on a small company than on a bigger company with a larger, more diverse, customer base. This is true for utilities, as well as for non-regulated companies.

As further evidence that smaller firms are riskier, investors generally demand greater returns from smaller firms to compensate for less marketability and liquidity of their securities. Kroll's Cost of Capital Navigator: U.S. Cost of Capital

Module ("Kroll") discusses the nature of the small-size phenomenon, providing an indication of the magnitude of the size premium based on several measures of size. In discussing "Size as a Predictor of Equity Premiums," Kroll states:

> The size effect is based on the empirical observation that companies of smaller size are associated with greater risk and, therefore, have greater cost of capital [sic]. The "size" of a company is one of the most important risk elements to consider when developing cost of equity capital estimates for use in valuing a business simply because size has been shown to be a *predictor* of equity returns. In other words, there is a significant (negative) relationship between size and historical equity returns - as size *decreases*, returns tend to *increase*, and vice versa. (footnote omitted) (emphasis in original)[48]

Furthermore, in "The Capital Asset Pricing Model: Theory and Evidence," Fama and French note size is indeed a risk factor which must be reflected when estimating the cost of common equity. On page 14, they note:

> . . . the higher average returns on small stocks and high book-to-market stocks reflect unidentified state variables that produce undiversifiable risks (covariances) in returns not captured in the market return and are priced separately from market betas.[49]

Based on this evidence, Fama and French proposed their three-factor model which includes a size variable in recognition of the effect size has on the cost of common equity.

Also, it is a basic financial principle that the use of funds invested, and not the source of funds, is what gives rise to the risk of any investment.[50] Eugene Brigham, a well-known authority, states:

> A number of researchers have observed that portfolios of small-firms (sic) have earned consistently higher average returns than those of large-firm stocks; this is called the "small-firm effect." On

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[48] Kroll, Cost of Capital Navigator: U.S. Cost of Capital Module, Size as a Predictor of Equity Returns, at 1.

[49] Fama & French, at 25-43.

[50] Brealey, Richard A. and Myers, Stewart C., Principles of Corporate Finance (McGraw-Hill Book Company, 1996), at 204-205, 229.

> the surface, it would seem to be advantageous to the small firms to provide average returns in a stock market that are higher than those of larger firms. In reality, it is bad news for the small firm; **what the small-firm effect means is that the capital market demands higher returns on stocks of small firms than on otherwise similar stocks of the large firms**. (emphasis added)[51]

Consistent with the financial principle of risk and return discussed above, increased relative risk due to small size must be considered in the allowed rate of return on common equity. Therefore, the Board's authorization of a cost rate of common equity in this proceeding must appropriately reflect the unique risks of JCP&L, including its small relative size, which is justified and supported above by evidence in the financial literature.

Q. Earlier you explained that credit ratings can act as a proxy for a firm's combined business and financial risks to equity owners. Do rating agencies account for company size in their bond ratings?

A. No. Neither S&P nor Moody's have minimum company size requirements for any given rating level. This means, all else equal, a relative size analysis must be conducted for equity investments in companies with similar bond ratings.

Q. Is there a way to quantify a relative risk adjustment due to JCP&L's small size when compared to the utility proxy group?

A. Yes. JCP&L has greater relative risk than the average utility in the Utility Proxy Group because of its smaller size, as measured by an estimated market capitalization of common equity for JCP&L.

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[51] Brigham, Eugene F., Fundamentals of Financial Management, Fifth Edition (The Dryden Press, 1989), at 623.

Table 9: Size as Measured by Market Capitalization for JCP&L and the Utility Proxy Group

	Market Capitalization* ($ Millions)	Times Greater than The Company
JCP&L	$3,037	
Utility Proxy Group	$22,798	7.5x
*From page 1 of Schedule DWD-7.		

JCP&L's estimated market capitalization was $3 billion as of December 30, 2022, compared with the market capitalization of the average company in the Utility Proxy Group of $23 billion as of December 30, 2022. The average company in the Utility Proxy Group has a market capitalization 7.5 times the size of JCP&L's estimated market capitalization.

As a result, it is necessary to upwardly adjust the indicated range of common equity cost rates attributable to the Utility Proxy Group to reflect the Company's greater risk due to their smaller relative size. The determination is based on the size premiums for portfolios of New York Stock Exchange, American Stock Exchange, and NASDAQ listed companies ranked by deciles for the 1926 to 2021 period.[52] The average size premium for the Utility Proxy Group with a market capitalization of $23 billion falls in the 2nd decile, while the Company's estimated market capitalization of $3 billion places it in the 6th decile. The size premium spread between the 2nd decile and the 6th decile is 0.75%. Even though a 0.75% upward size adjustment is indicated, I applied a size premium of 0.15% to the Company's indicated common equity cost rate in order to be conservative.

[52] Source: Kroll, Cost of Capital Navigator.

Q. Since JCP&L is part of a larger company, why is the size of the total company not more appropriate to use when determining the size adjustment?

A. As discussed previously, rates are set using the stand-alone principle, which maintains that the utility operations of a diversified firm should be regulated as though they were independent (i.e., without the impact of affiliated companies). Because of this, the return derived in this proceeding will not apply to FE's operations as a whole, but only JCP&L's. FE is the sum of its constituent parts, including those constituent parts' ROEs. Potential investors in the parent company are aware that it is a combination of operations in each state, and that each state's operations experience the operating risks specific to their jurisdiction. The market's expectation of FE's return is commensurate with the realities of the Company's composite operations in each of the states in which it operates.

B. Credit Risk Adjustment

Q. Please discuss your proposed credit risk adjustment.

A. JCP&L's Moody's long-term issuer rating is A3, which is one credit rating notch better than the average Moody's long-term issuer rating for the Utility Proxy Group of Baa1.[53] Hence, a downward credit risk adjustment is necessary to reflect the lower credit rating, i.e., A3, of JCP&L relative to the Baa1 average Moody's bond rating of the Utility Proxy Group.[54]

An indication of the magnitude of the necessary downward adjustment to reflect the lower credit risk inherent in an A3 bond rating is one-third of a recent

[53] Source of Information: S&P Global Market Intelligence.
[54] As shown on page 5 of Schedule DWD-3.

three-month average spread between Moody's A2 and Baa2-rated public utility bond yields of 0.30%, shown on page 4 of Schedule DWD-3, or 0.10%.[55]

C. Flotation Cost Adjustment

Q. What are flotation costs?

A. Flotation costs are those costs associated with the sale of new issuances of common stock. They include market pressure and the mandatory unavoidable costs of issuance (e.g., underwriting fees and out-of-pocket costs for printing, legal, registration, etc.). For every dollar raised through debt or equity offerings, the Company receives less than one full dollar in financing.

Q. Why is it important to recognize flotation costs in the allowed common equity cost rate?

A. It is important because there is no other mechanism in the ratemaking paradigm through which such costs can be recognized and recovered. Because these costs are real, necessary, and legitimate, recovery of these costs should be permitted. As noted by Morin:

> The costs of issuing these securities are just as real as operating and maintenance expenses or costs incurred to build utility plants, and fair regulatory treatment must permit recovery of these costs….
>
> The simple fact of the matter is that common equity capital is not free…[Flotation costs] must be recovered through a rate of return adjustment.[56]

[55] 0.10% = 0.30% * (1/3).
[56] Morin, at 329.

Q. Should flotation costs be recognized only if there was an issuance during the test year or there is an imminent post-test year issuance of additional common stock?

A. No. As noted above, there is no mechanism to recapture such costs in the ratemaking paradigm other than an adjustment to the allowed common equity cost rate. Flotation costs are charged to capital accounts and are not expensed on a utility's income statement. As such, flotation costs are analogous to capital investments, albeit negative, reflected on the balance sheet. Recovery of capital investments relates to the expected useful lives of the investment. Since common equity has a very long and indefinite life (assumed to be infinity in the standard regulatory DCF model), flotation costs should be recovered through an adjustment to common equity cost rate, even when there has not been an issuance during the test year, or in the absence of an expected imminent issuance of additional shares of common stock.

Historical flotation costs are a permanent loss of investment to the utility and should be accounted for. When any company, including a utility, issues common stock, flotation costs are incurred for legal, accounting, printing fees and the like. For each dollar of issuing market price, a small percentage is expensed and is permanently unavailable for investment in utility rate base. Since these expenses are charged to capital accounts and not expensed on the income statement, the only way to restore the full value of that dollar of issuing price with an assumed investor required return of 10% is for the net investment, $0.95, to earn more than 10% to net back to the investor a fair return on that dollar. In other words, if a

company issues stock at $1.00 with 5% in flotation costs, it will net $0.95 in investment. Assuming the investor in that stock requires a 10% return on their invested $1.00 (i.e., a return of $0.10), the company needs to earn approximately 10.5% on its invested $0.95 to receive a $0.10 return.

Q. Do the common equity cost rate models you have used already reflect investors' anticipation of flotation costs?

A. No. All of these models assume no transaction costs. The literature is quite clear that these costs are not reflected in the market prices paid for common stocks. For example, Brigham and Daves confirm this and provide the methodology utilized to calculate the flotation adjustment.[57] In addition, Morin confirms the need for such an adjustment even when no new equity issuance is imminent.[58] Consequently, it is proper to include a flotation cost adjustment when using cost of common equity models to estimate the common equity cost rate.

Q. How did you calculate the flotation cost allowance?

A. I modified the DCF calculation to provide a dividend yield that would reimburse investors for issuance costs in accordance with the method cited in literature by Brigham and Daves, as well as by Morin. The flotation cost adjustment recognizes the actual costs of issuing equity that were incurred by FE. Based on the issuance costs shown on page 1 of Schedule DWD-8, an adjustment of 0.19% is required to reflect the flotation costs applicable to the Utility Proxy Group.

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[57] Eugene F. Brigham and Phillip R. Daves, Intermediate Financial Management, 9th Edition, Thomson/Southwestern, at p. 342.

[58] Morin, at 342.

Q. What is the indicated cost of common equity after your company-specific adjustments?

A. Applying the 0.15% size adjustment, the negative 0.10% credit risk adjustment, and the 0.19% flotation cost adjustment to the indicated range of common equity cost rates between 10.04% and 11.04% results in a range of common equity cost rates between 10.28% and 11.28%.

VIII. CONCLUSION

Q. What is your recommended roe for JCP&L?

A. Given the discussion above and the results from the analyses in this testimony, I recommend that an ROE of 10.40%, within a range between 10.28% and 11.28%, is appropriate for the Company at this time.

Q. In your opinion, is your proposed ROE of 10.40% fair and reasonable to JCP&L and its customers?

A. Yes, it is.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Table of Contents
to Exhibit JC-7

Jersey Central Power & Light Company
Recommended Capital Structure and Cost Rates
for Ratemaking Purposes

Type Of Capital	Ratios (1)	Cost Rate		Weighted Cost Rate
Long-Term Debt	48.10%	4.572%	(1)	2.20%
Common Equity	51.90%	10.40%	(2)	5.40%
Total	100.00%			7.60%

Notes:

(1) Company-provided.
(2) From page 2 of this Schedule.

Jersey Central Power & Light Company
Brief Summary of Common Equity Cost Rate

Line No.	Principal Methods	Proxy Group of Thirteen Electric Utilities
1.	Discounted Cash Flow Model (DCF) (1)	9.29%
2.	Risk Premium Model (RPM) (2)	11.64%
3.	Capital Asset Pricing Model (CAPM) (3)	11.79%
4.	Market Models Applied to Comparable Risk, Non-Price Regulated Companies (4)	12.58%
5.	Indicated Common Equity Cost Rate before Adjustment for Unique Risk	10.04% - 11.04%
6.	Business Risk Adjustment (5)	0.15%
7.	Credit Risk Adjustment (6)	-0.10%
8.	Flotation Costs (7)	0.19%
9.	Indicated Common Equity Cost Rate after Adjustment	10.28% - 11.28%
10.	Recommended Common Equity Cost Rate	10.40%

Notes:
(1) From Schedule DWD-2.
(2) From page 1 of Schedule DWD-3.
(3) From page 1 of Schedule DWD-4.
(4) From page 1 of Schedule DWD-6.
(5) Business risk adjustment to reflect Jersey Central Power & Light Company's unique risk compared to the Utility Proxy Group as detailed in the accompanying direct testimony.
(6) Credit risk adjustment to reflect the Company's Moody's credit rating of A3 as compared to the Baa1 average credit rating of the Utility Proxy Group.
(7) From page 1 of Schedule DWD-8.

Jersey Central Power & Light Company
Indicated Common Equity Cost Rate Using the Discounted Cash Flow Model for the
Proxy Group of Thirteen Electric Utilities

Proxy Group of Thirteen Electric Utilities	[1] Average Dividend Yield (1)	[2] Value Line Projected Five Year Growth in EPS (2)	[3] Zack's Five Year Projected Growth Rate in EPS	[4] Yahoo! Finance Projected Five Year Growth in EPS	[5] Average Projected Five Year Growth in EPS (3)	[6] Adjusted Dividend Yield (4)	[7] Indicated Common Equity Cost Rate (5)
Alliant Energy Corporation	3.20 %	6.00 %	5.90 %	5.53 %	5.81 %	3.29 %	9.10 %
Ameren Corporation	2.81	6.50	6.90	5.91	6.44	2.90	9.34
American Electric Power Corporation	3.64	6.50	6.10	6.18	6.26	3.75	10.01
Duke Energy Corporation	4.19	5.00	5.50	6.15	5.55	4.31	9.86
Edison International	4.80	16.00	2.60	4.40	7.67	4.98	12.65
Entergy Corporation	3.90	4.00	6.80	6.19	5.66	4.01	9.67
Evergy, Inc.	4.08	7.50	5.30	2.43	5.08	4.18	9.26
Eversource Energy	3.22	6.50	6.50	6.42	6.47	3.32	9.79
IDACORP, Inc.	3.05	4.00	3.40	3.40	3.60	3.10	6.70
NorthWestern Corporation	4.61	2.50	1.70	4.50	2.90	4.68	7.58
OGE Energy Corporation	4.37	6.50	5.00	1.90	4.47	4.47	8.94
Portland General Electric Company	3.90	4.50	5.30	1.39	3.73	3.97	7.70
Xcel Energy Inc.	2.93	6.00	6.50	6.80	6.43	3.02	9.45
						Average	9.24 %
						Median	9.34 %
					Average of Mean and Median		9.29 %

Notes:

(1) Indicated dividend at 12/30/2022 divided by the average closing price of the last 60 trading days ending 12/30/2022 for each company.
(2) From pages 3 through 15 of this Schedule.
(3) Average of columns 2 through 4 excluding negative growth rates.
(4) This reflects a growth rate component equal to one-half the conclusion of growth rate (from column 6) x column 1 to reflect the periodic payment of dividends (Gordon Model) as opposed to the continuous payment. Thus, for Alliant Energy Corporation, 3.20% x (1+(1/2 x 5.81%)) = 3.29%.
(5) Column 6 + column 7.

Source of Information:

Value Line Investment Survey
www.zacks.com Downloaded on 12/30/2022
www.yahoo.com Downloaded on 12/30/2022

Jersey Central Power & Light Company
Hypothetical Example of the Inadequacy of
A DCF Return Rate Related to Book Value
When Market Value is Greater / Less than Book Value

Line No.		[1] Market Value	[2] Book Value with Market to Book Ratio of 200%	[3] Book Value with Market to Book Ratio of 80%
1.	Per Share	$ 30.00	$ 15.00	$ 37.50
2.	DCF Cost Rate (1)	10.00%	10.00%	10.00%
3.	Return in Dollars	$ 3.000	$ 1.500	$ 3.750
4.	Dividends (2)	$ 0.900	$ 0.900	$ 0.900
5.	Growth in Dollars	$ 2.100	$ 0.600	$ 2.850
6.	Return on Market Value	10.00%	5.00% (3)	12.50% (4)
7.	Rate of Growth on Market Value	7.00% (5)	2.00% (6)	9.50% (7)

Notes:
(1) Comprised of 3.0% dividend yield and 6.0% growth.
(2) $30.00 * 3.0% yield = $0.900.
(3) $1.50 / $30.00 market value = 5.00%.
(4) $3.75 / $30.00 market value = 12.50%.
(5) Expected rate of growth per market based DCF model.
(6) Actual rate of growth when DCF cost rate is applied to book value ($1.500 possible earnings - $0.900 dividends = $0.600 for growth / $30.00 market value = 2.00%).
(7) Actual rate of growth when DCF cost rate is applied to book value ($3.750 possible earnings - $0.900 dividends = $2.850 for growth / $30.00 market value = 9.50%).

ALLIANT ENERGY NDQ-LNT

RECENT PRICE **55.78** | P/E RATIO **20.3** (Trailing: 21.0 Median: 20.0) | RELATIVE P/E RATIO **1.25** | DIV'D YLD **3.2%** | **VALUE LINE**

TIMELINESS 4 Lowered 11/18/22
SAFETY 2 Raised 9/28/07
TECHNICAL 4 Lowered 12/9/22
BETA .85 (1.00 = Market)

18-Month Target Price Range

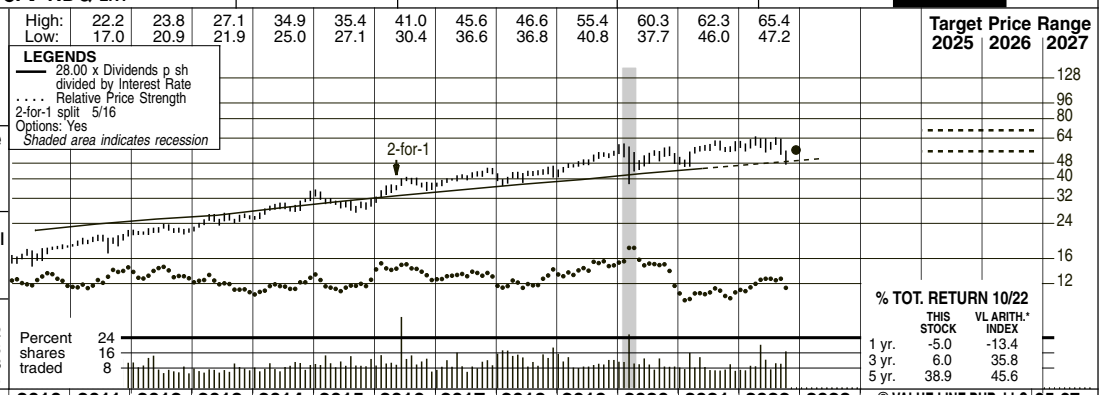
Low-High	Midpoint (% to Mid)
$45-$80	$63 (10%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+25%)	*9%*
Low	55	(Nil)	*3%*

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	265	314	278
to Sell	259	232	263
Hld's(000)	195423	188290	192005



% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-5.0	-13.4
3 yr.	6.0	35.8
5 yr.	38.9	45.6

2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
14.46	15.57	16.67	15.51	15.40	16.51	13.94	14.77	15.10	14.34	14.58	14.62	14.97	14.89	13.67	14.65	*16.35*	*16.90*	Revenues per sh	*18.50*
2.16	2.56	2.28	2.10	2.60	2.75	2.95	3.34	3.49	3.45	3.43	3.97	4.32	4.59	4.92	5.25	*5.50*	*5.75*	"Cash Flow" per sh	*6.75*
1.03	1.35	1.27	.95	1.38	1.38	1.53	1.65	1.74	1.69	1.65	1.99	2.19	2.33	2.47	2.63	*2.70*	*2.95*	Earnings per sh A	*3.50*
.58	.64	.70	.75	.79	.85	.90	.94	1.02	1.10	1.18	1.26	1.34	1.42	1.52	1.61	*1.71*	*1.81*	Div'd Decl'd per sh B ■ †	*2.15*
1.71	2.46	3.98	5.43	3.91	3.03	5.22	3.32	3.78	4.25	5.26	6.34	6.92	6.69	5.47	4.67	*5.90*	*5.90*	Cap'l Spending per sh	*6.25*
11.42	12.15	12.78	12.54	13.05	13.57	14.12	14.79	15.54	16.41	16.96	18.08	19.43	21.24	22.76	23.91	*25.05*	*26.25*	Book Value per sh C	*30.25*
232.25	220.72	220.90	221.31	221.79	222.04	221.97	221.89	221.87	226.92	227.67	231.35	236.06	245.02	249.87	250.47	*251.00*	*251.50*	Common Shs Outst'g D	*253.00*
16.8	15.1	13.4	13.9	12.5	14.5	14.5	15.3	16.6	18.1	22.3	20.6	19.1	21.2	21.2	21.2	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*18.0*
.91	.80	.81	.93	.80	.91	.92	.86	.87	.91	1.17	1.04	1.03	1.13	1.09	1.13			Relative P/E Ratio	*1.00*
3.3%	3.1%	4.1%	5.7%	4.6%	4.3%	4.1%	3.7%	3.5%	3.6%	3.2%	3.1%	3.2%	2.9%	2.9%	2.9%			Avg Ann'l Div'd Yield	*3.7%*
3094.5	3276.8	3350.3	3253.6	3320.0	3382.2	3534.5	3647.7	3416.0	3669.0	*4100*	*4250*	Revenues ($mill)	*4700*
337.8	382.1	395.7	390.9	384.0	466.1	522.3	567.4	624.0	674.0	*700*	*745*	Net Profit ($mill)	*885*
21.5%	12.4%	10.1%	15.3%	13.4%	12.5%	8.4%	10.8%	10.8%	NMF	*4.0%*	*4.0%*	Income Tax Rate	*4.0%*
6.5%	8.1%	8.8%	9.4%	16.3%	10.7%	14.5%	16.3%	8.8%	3.7%	*4.0%*	*5.0%*	AFUDC % to Net Profit	*6.0%*
48.4%	46.1%	49.7%	47.3%	51.5%	47.8%	52.3%	50.6%	53.5%	52.9%	*54.5%*	*54.0%*	Long-Term Debt Ratio	*55.0%*
48.4%	50.8%	47.5%	50.0%	46.1%	49.8%	45.7%	47.6%	44.9%	47.1%	*45.5%*	*46.0%*	Common Equity Ratio	*45.0%*
6476.6	6461.0	7257.2	7446.3	8377.6	8392.8	10032	10938	12657	12725	*13875*	*14425*	Total Capital ($mill)	*17100*
7838.0	7147.3	6442.0	8970.2	9809.9	10798	12462	13527	14336	14987	*16025*	*17075*	Net Plant ($mill)	*20300*
6.3%	7.0%	6.5%	6.3%	5.6%	6.7%	6.3%	6.3%	5.9%	6.3%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
10.1%	11.0%	10.8%	10.0%	9.5%	10.6%	10.9%	10.5%	10.6%	11.3%	*11.0%*	*11.5%*	Return on Shr. Equity	*11.5%*
10.3%	11.3%	11.2%	10.2%	9.7%	10.9%	11.2%	10.7%	10.8%	11.0%	*11.0%*	*11.5%*	Return on Com Equity E	*11.5%*
3.9%	4.9%	4.6%	3.6%	2.8%	4.0%	4.4%	4.2%	4.2%	4.3%	*4.5%*	*4.5%*	Retained to Com Eq	*4.5%*
64%	57%	60%	66%	72%	64%	62%	61%	62%	62%	*61%*	*61%*	All Div'ds to Net Prof	*61%*

CAPITAL STRUCTURE as of 9/30/22
Total Debt $8611 mill. **Due in 5 Yrs** $2126 mill.
LT Debt $7570 mill. **LT Interest** $272 mill.
(LT interest earned: 3.3x)

Leases, Uncapitalized Annual rentals $2 mill.

Pension Assets-12/21 $1011 mill.
Oblig $1251 mill.

Pfd Stock None

Common Stock 251,021,830 shs.

MARKET CAP: $14.0 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-2.2	-2.3	+3.7
Avg. Indust. Use (MWH)	11448	11134	NA
Avg. Indust. Revs. per KWH (¢)	6.98	7.55	7.64
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	5626	5496	5486
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.6	+.6	+.8
Fixed Charge Cov. (%)	265	251	259

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-1.0%	-.5%	*4.5%*
"Cash Flow"	7.0%	7.5%	*5.5%*
Earnings	7.0%	8.0%	*6.0%*
Dividends	6.5%	6.5%	*6.0%*
Book Value	5.5%	7.0%	*5.0%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	987.2	790.2	990.2	880.1	3647.7
2020	916	763	920	817	3416.0
2021	901	817	1024	927	3669.0
2022	1068	943	1135	*954*	*4100*
2023	*1100*	*925*	*1175*	*1050*	*4250*

EARNINGS PER SHARE A

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.53	.40	.94	.46	2.33
2020	.72	.54	.94	.26	2.47
2021	.68	.57	1.02	.35	2.63
2022	.77	.63	.90	*.40*	*2.70*
2023	*.80*	*.65*	*1.05*	*.45*	*2.95*

QUARTERLY DIVIDENDS PAID B ■ †

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.335	.335	.335	.335	1.34
2019	.355	.355	.355	.355	1.42
2020	.38	.38	.38	.38	1.52
2021	.4025	.4025	.4025	.4025	1.61
2022	.4275	.4275	.4275	.4275	

BUSINESS: Alliant Energy Corporation (formerly Interstate Energy) is a holding company formed through the merger of WPL Holdings, IES Industries, and Interstate Power. Supplies electricity to 985,000 customers and gas to 425,000 customers in Wisconsin, Iowa, and Minnesota. Electric revenue by state: WI, 43%; IA, 56%. MN, 1%. Electric revenue: residential, 36%; commercial, 25%; industrial, 29%; wholesale, 8%; other, 2%. Generating sources: coal, 32%; gas, 32%; wind, 16%; other, 1%; purchased, 19%. Fuel costs: 25% of revs. '21 reported deprec. rates: 2.9%-6.1%. Has 3,300 employees. Chairman, President & CEO: John O. Larsen. Inc.: Wisconsin. Address: 4902 N. Biltmore Lane, Madison, Wisconsin 53718-2148. Tel.: 608-458-3311. Internet: www.alliantenergy.com.

Alliant Energy came up a bit short in the September quarter. Indeed, on a reported basis, the Wisconsin-based electric utility earned $0.90 a share in the period, down 12% year over year, even as overall revenue rose 11%, to nearly $1.14 billion. Weighing on EPS was, among other things, a one-time charge below the operating line (included in our estimates). Notably, Alliant wrote down the value of tax assets on its balance sheet after Iowa's Department of Revenue announced a reduction in state levies on corporate income beginning next year. That said, operating conditions remained generally favorable, with warmer-than-normal weather driving increased air-conditioner and electricity use across Alliant's three-state footprint.

The utility's investment roadmap includes a notable amount of energy storage. In late September, Alliant filed a plan with the Public Service Commission of Wisconsin, calling for the addition of 175 megawatts of battery storage in the state. Specifically, the facilities would be located in Grant and Wood counties, alongside two previously-approved solar arrays. Importantly, they'd provide bridge power for more than 180,000 homes at times when sun- and wind-power generation is inadequate.

The Inflation Reduction Act (IRA) that was signed into law in mid-August is expected to be a big benefit. As we understand it, new financing options under the IRA will enable Alliant Energy to take full ownership of 12 solar-power farms that it currently shares with several investment partners. According to a recent report, the transition could save the utility and its customers upwards of $138 million.

Shares of Alliant Energy are ranked 4 (Below Average) for relative year-ahead price performance. At the recent quotation, we think that buy-and-hold investors will also do better elsewhere. Notably, at 3.2%, the dividend yield is below both the utility average and less-risky returns offered by United States Treasuries. Prospects over the next 18 months and the 3- to 5-year period are also subpar. Like many electric utility issues, the recent quotation is within our 2025-2027 Target Price Range.

Nils C. Van Liew *December 9, 2022*

(A) Diluted EPS. Excl. nonrecurring losses: '11, 1¢; '12, 8¢. '20 & '21 EPS don't sum due to rounding. Next earnings report due late Feb. **(B)** Dividends historically paid in mid-Feb., May, Aug., and Nov. ■ Dividend reinvestment plan avail. † Shareholder investment plan avail. **(C)** Incl. deferred charges. In '21: $1,980 mill., $7.91/sh. **(D)** In millions, adj. for split. **(E)** Rate base: Orig. cost. Rates all'd on com. eq. in IA in '20: various; in WI in '22: 10%; earned on avg. com. eq., '21: 11.3%. Regulatory Climate: Wisconsin, Above Average; Iowa, Average.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	70
Earnings Predictability	95

AMEREN NYSE-AEE

RECENT PRICE **87.94** | P/E RATIO **20.8** (Trailing: 22.0 Median: 19.0) | RELATIVE P/E RATIO **1.28** | DIV'D YLD **2.8%** | **VALUE LINE**

TIMELINESS 4 Lowered 12/2/22
SAFETY 1 Raised 9/10/21
TECHNICAL 4 Lowered 12/9/22
BETA .85 (1.00 = Market)

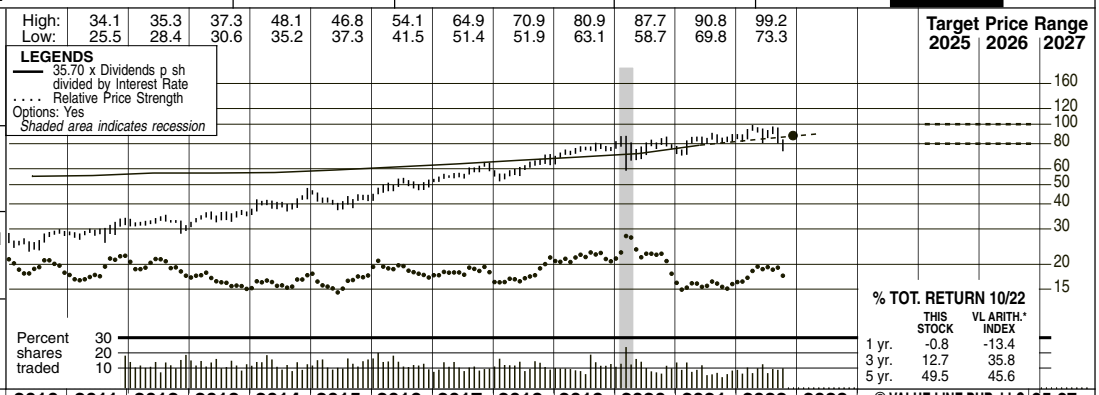
18-Month Target Price Range
Low-High **Midpoint (% to Mid)**
$81-$129 $105 (20%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	100	(+15%)	*6%*
Low	80	(-10%)	*1%*

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	294	305	287
to Sell	262	257	274
Hld's(000)	200507	201631	204282



2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
33.30	36.23	36.92	29.87	31.77	31.04	28.14	24.06	24.95	25.13	25.04	25.46	25.73	24.00	22.87	24.81	*27.25*	*28.10*	Revenues per sh	*30.00*
6.02	6.76	6.44	6.06	6.33	5.87	5.87	5.25	5.77	6.08	6.59	6.80	7.64	7.83	8.08	8.89	*9.50*	*10.05*	"Cash Flow" per sh	*11.75*
2.66	2.98	2.88	2.78	2.77	2.47	2.41	2.10	2.40	2.38	2.68	2.77	3.32	3.35	3.50	3.84	*4.10*	*4.35*	Earnings per sh [A]	*5.25*
2.54	2.54	2.54	1.54	1.54	1.56	1.60	1.60	1.61	1.66	1.72	1.78	1.85	1.92	2.00	2.20	*2.36*	*2.52*	Div'd Decl'd per sh [B] ■	*3.10*
4.99	6.96	9.75	7.51	4.66	4.50	5.49	5.87	7.66	8.12	8.78	9.05	9.56	9.92	13.02	13.67	*12.90*	*12.55*	Cap'l Spending per sh	*13.00*
31.86	32.41	32.80	33.08	32.15	32.64	27.27	26.97	27.67	28.63	29.27	29.61	31.21	32.73	35.29	37.64	*40.20*	*42.90*	Book Value per sh [C]	*51.25*
206.60	208.30	212.30	237.40	240.40	242.60	242.63	242.63	242.63	242.63	242.63	242.63	244.50	246.20	253.30	257.70	*262.50*	*267.00*	Common Shs Outst'g [D]	*280.00*
19.4	17.4	14.2	9.3	9.7	11.9	13.4	16.5	16.7	17.5	18.3	20.6	18.3	22.1	22.2	21.4	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*17.5*
1.05	.92	.85	.62	.62	.75	.85	.93	.88	.88	.96	1.04	.99	1.18	1.14	1.14			Relative P/E Ratio	*.95*
4.9%	4.9%	6.2%	6.0%	5.8%	5.3%	5.0%	4.6%	4.0%	4.0%	3.5%	3.1%	3.0%	2.6%	2.6%	2.7%			Avg Ann'l Div'd Yield	*3.4%*
6828.0	5838.0	6053.0	6098.0	6076.0	6177.0	6291.0	5910.0	5794.0	6394.0	*7150*	*7500*	Revenues ($mill)	*8400*
589.0	518.0	593.0	585.0	659.0	683.0	821.0	834.0	877.0	995.0	*1075*	*1165*	Net Profit ($mill)	*1455*
36.9%	37.5%	38.9%	38.3%	36.7%	38.2%	22.4%	17.9%	15.0%	13.6%	*12.0%*	*12.0%*	Income Tax Rate	*12.0%*
6.1%	7.1%	5.7%	5.1%	4.1%	5.6%	6.9%	5.8%	5.5%	6.0%	*6.0%*	*5.0%*	AFUDC % to Net Profit	*4.0%*
49.5%	45.2%	47.2%	49.3%	47.7%	49.2%	50.3%	52.1%	55.0%	56.1%	*55.5%*	*53.5%*	Long-Term Debt Ratio	*51.0%*
49.4%	53.7%	51.7%	49.7%	51.3%	49.8%	48.8%	47.1%	44.3%	43.3%	*44.0%*	*46.0%*	Common Equity Ratio	*48.5%*
13384	12190	12975	13968	13840	14420	15632	17116	20158	22391	*23900*	*24950*	Total Capital ($mill)	*29500*
16096	16205	17424	18799	20113	21466	22810	24376	26807	29261	*31225*	*33050*	Net Plant ($mill)	*38400*
6.0%	5.6%	5.8%	5.3%	6.0%	6.0%	6.4%	6.0%	5.3%	5.3%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
8.7%	7.7%	8.7%	8.3%	9.1%	9.3%	10.6%	10.2%	9.7%	10.1%	*10.0%*	*10.0%*	Return on Shr. Equity	*10.0%*
8.8%	7.8%	8.7%	8.3%	9.2%	9.4%	10.7%	10.3%	9.7%	10.2%	*10.0%*	*10.0%*	Return on Com Equity [E]	*10.0%*
3.0%	1.9%	2.9%	2.5%	3.3%	3.4%	4.8%	4.4%	4.2%	4.4%	*4.5%*	*4.5%*	Retained to Com Eq	*4.0%*
66%	76%	67%	70%	64%	64%	56%	57%	57%	57%	*58%*	*58%*	All Div'ds to Net Prof	*60%*

CAPITAL STRUCTURE as of 9/30/22
Total Debt $14798 mill. **Due in 5 Yrs** $3446 mill.
LT Debt $13577 mill. **LT Interest** $436 mill.
(LT interest earned: 3.8x)
Pension Assets-12/21 $5745 mill.
Oblig $5457 mill.
Pfd Stock $129 mill. **Pfd Div'd** $5 mill.
807,595 sh. $3.50 to $5.50 cum. (no par), $100 stated val., redeem. $102.176-$110/sh.; 487,508 sh. 4.00% to 5.16%, $100 par, redeem. $100-$104.30/sh.
Common Stock 258,522,169 shs.
as of 10/31/22
MARKET CAP: $23 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-3.5	-5.6	+2.1
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	307	291	325

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-2.5%	-1.0%	*4.0%*
"Cash Flow"	3.0%	6.0%	*6.0%*
Earnings	3.0%	7.5%	*6.5%*
Dividends	3.0%	4.0%	*7.0%*
Book Value	1.0%	4.5%	*6.5%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1556	1379	1659	1316	5910
2020	1440	1398	1628	1328	5794
2021	1566	1472	1811	1545	6394
2022	1879	1726	2306	*1239*	*7150*
2023	*1900*	*1700*	*2100*	*1800*	*7500*

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.78	.72	1.47	.38	3.35
2020	.59	.98	1.47	.46	3.50
2021	.91	.80	1.65	.48	3.84
2022	.97	.80	1.74	*.59*	*4.10*
2023	*1.00*	*.90*	*1.80*	*.65*	*4.35*

QUARTERLY DIVIDENDS PAID [B] ■

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.4575	.4575	.4575	.475	1.85
2019	.475	.475	.475	.495	1.92
2020	.495	.495	.495	.515	2.00
2021	.55	.55	.55	.55	2.20
2022	.59	.59	.59	.59	

BUSINESS: Ameren Corporation is a holding company formed through the merger of Union Electric and CIPSCO. Has 1.2 million electric and 127,000 gas customers in Missouri; 1.2 million electric and 813,000 gas customers in Illinois. Discontinued nonregulated power-generation operation in '13. Electric revenue breakdown: residential, 49%; commercial, 34%; industrial, 8%; other, 9%. Generating sources: coal, 73%; nuclear, 11%; hydro & other, 9%; purchased, 7%. Fuel costs: 25% of revenues. '21 reported deprec. rates: 3%-4%. Has 9,100 employees. Chairman: Warner L. Baxter. President & CEO: Martin J. Lyons, Jr. Inc.: Missouri. Address: One Ameren Plaza, 1901 Chouteau Ave., P.O. Box 66149, St. Louis, MO 63166-6149. Tel.: 314-621-3222. Internet: www.ameren.com.

Ameren reported in-line results for the September quarter. Earnings per share of $1.74 were a penny higher than our estimate and 5% greater than the year-ago tally. Earnings at Ameren Missouri, the largest segment, benefited from higher electric service rates. This was partially offset by higher operations and maintenance expenses derived from unfavorable market returns and company-owned life insurance investments. Earnings at the three remaining business segments were solid, primarily due to increased investments in infrastructure.

The company's guidance has improved a bit. Due to strong execution, management narrowed the 2022 earnings guidance to a range of $4.00 to $4.15 per share. This compares to the initial guidance range of $3.95 to $4.15 per share. Importantly, the year-to-date benefits it has seen from weather and higher-than-expected 30-year Treasury rates are mostly being offset by the aforementioned company-owned life insurance investment performance, as well as higher than expected short-term and long-term borrowing rates. The current five-year plan includes a 6% to 8% compounded annual growth rate for earnings from 2022 through 2026. This should be driven primarily by strong rate base growth and infrastructure investment. It expects dividend growth to be in line with long-term earnings growth and is planning for a payout ratio range of 55% to 70%.

Business investment is paying off. At Ameren Missouri, the company estimates that over 6.5 million minutes of customer outages have been avoided in 2022 due to recent infrastructure investments. Meanwhile, the Inflation Reduction Act (IRA) was enacted in August, and is designed to help reduce the cost of the clean energy transition. It provides tax credits for wind, solar, and nuclear energy centers, as well as energy storage, carbon capture utilization and hydrogen development. The incentives in the IRA align well with the companywide goal of reaching net zero carbon emissions by 2045.

The dividend yield of this high-quality stock is below the utility mean. The recent price is within our 2025-2027 Target Price Range.

Kevin Downing *December 9, 2022*

(A) Diluted EPS. Excl. nonrec. gain (losses): '10, ($2.19); '11, (32¢); '12, ($6.42); '17, (63¢); gain (loss) from discontinued ops.: '13, (92¢); '15, 21¢. Next earnings report due mid-Feb. **(B)** Div'ds paid late Mar., June, Sept., & Dec. ■ Div'd reinvest. plan avail. **(C)** Incl. intang. In '21: $6.60/sh. **(D)** In mill. **(E)** Rate base: Orig. cost depr. Rate allowed on com. eq. in MO in '22: elec. & gas, none specified; in IL: electric, varies; in '21: gas, 9.67%; earned on avg. com. eq., '21: 10.6%. Regulatory Climate: MO, Average; IL, Below Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	85
Earnings Predictability	95

AMERICAN ELEC. PWR. NDQ-AEP

RECENT PRICE **95.22** | P/E RATIO **18.6** (Trailing: 19.7 Median: 17.0) | RELATIVE P/E RATIO **1.14** | DIV'D YLD **3.5%** | **VALUE LINE**

TIMELINESS 3 Raised 4/1/22
SAFETY 1 Raised 3/17/17
TECHNICAL 2 Lowered 11/18/22
BETA .75 (1.00 = Market)

18-Month Target Price Range

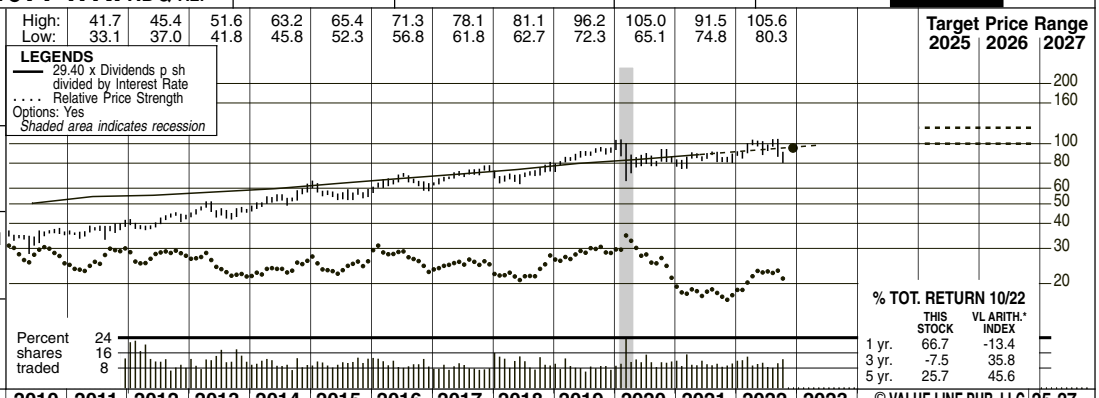
Low-High	Midpoint (% to Mid)
$89-$127	$108 (15%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	120	(+25%)	*9%*
Low	100	(+5%)	*5%*

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	673	634	624
to Sell	475	521	499
Hld's(000)	382433	385400	384675



2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
31.82	33.41	35.56	28.22	30.01	31.27	30.77	31.48	34.78	33.51	33.31	31.35	32.84	31.49	30.04	33.30	***35.20***	***35.95***	Revenues per sh	***38.55***
6.67	6.80	6.84	6.32	6.29	6.83	6.92	7.02	7.57	7.98	8.47	7.95	8.77	9.35	10.28	10.98	***11.50***	***11.95***	"Cash Flow" per sh	***14.00***
2.86	2.86	2.99	2.97	2.60	3.13	2.98	3.18	3.34	3.59	4.23	3.62	3.90	4.08	4.42	4.96	***5.00***	***5.35***	Earnings per sh A	***6.50***
1.50	1.58	1.64	1.64	1.71	1.85	1.88	1.95	2.03	2.15	2.27	2.39	2.53	2.71	2.84	3.00	***3.17***	***3.35***	Div'd Decl'd per sh B ■ †	***4.00***
8.89	8.88	9.83	6.19	5.07	5.74	6.45	7.75	8.68	9.37	9.98	11.79	12.89	12.43	12.72	11.43	***15.35***	***14.15***	Cap'l Spending per sh	***14.00***
23.73	25.17	26.33	27.49	28.33	30.33	31.37	32.98	34.37	36.44	35.38	37.17	38.58	39.73	41.38	44.49	***47.30***	***50.30***	Book Value per sh C	***59.00***
396.67	400.43	406.07	478.05	480.81	483.42	485.67	487.78	489.40	491.05	491.71	492.01	493.25	494.17	496.60	504.21	***514.00***	***523.00***	Common Shs Outst'g D	***545.00***
12.9	16.3	13.1	10.0	13.4	11.9	13.8	14.5	15.9	15.8	15.2	19.3	18.0	21.4	19.6	17.1	***Bold figures are Value Line estimates***		Avg Ann'l P/E Ratio	***17.0***
.70	.87	.79	.67	.85	.75	.88	.81	.84	.80	.80	.97	.97	1.14	1.01	.93			Relative P/E Ratio	***.95***
4.1%	3.4%	4.2%	5.5%	4.9%	5.0%	4.6%	4.2%	3.8%	3.8%	3.5%	3.4%	3.6%	3.1%	3.3%	3.5%			Avg Ann'l Div'd Yield	***3.6%***
14945	15357	17020	16453	16380	15425	16196	15561	14919	16792	***18100***	***18800***	Revenues ($mill)	***21000***
1443.0	1549.0	1634.0	1763.4	2073.6	1783.2	1923.8	2019.0	2200.1	2488.1	***2580***	***2775***	Net Profit ($mill)	***3565***
33.9%	36.2%	37.8%	35.1%	26.8%	33.7%	5.8%	.7%	1.9%	4.6%	***7.0%***	***7.0%***	Income Tax Rate	***7.0%***
11.2%	7.3%	9.0%	11.0%	8.0%	8.0%	10.7%	12.7%	9.7%	7.8%	***7.0%***	***7.0%***	AFUDC % to Net Profit	***5.0%***
50.6%	51.1%	49.0%	49.8%	50.0%	51.5%	53.2%	56.1%	58.5%	58.3%	***58.0%***	***58.0%***	Long-Term Debt Ratio	***57.5%***
49.4%	48.9%	51.0%	50.2%	50.0%	48.5%	46.8%	43.9%	41.5%	41.7%	***42.0%***	***42.0%***	Common Equity Ratio	***42.5%***
30823	32913	33001	35633	34775	37707	40677	44759	49537	53734	***57775***	***62950***	Total Capital ($mill)	***75900***
38763	40997	44117	46133	45639	50262	55099	60138	63902	66001	***70650***	***74600***	Net Plant ($mill)	***87300***
6.1%	6.0%	6.3%	6.1%	7.2%	5.9%	5.9%	5.6%	5.6%	5.6%	***4.5%***	***4.5%***	Return on Total Cap'l	***5.5%***
9.5%	9.6%	9.7%	9.9%	11.9%	9.8%	10.1%	10.3%	10.7%	11.1%	***11.0%***	***10.5%***	Return on Shr. Equity	***11.0%***
9.5%	9.6%	9.7%	9.9%	11.9%	9.8%	10.1%	10.3%	10.7%	11.1%	***11.0%***	***10.5%***	Return on Com Equity E	***11.0%***
3.5%	3.7%	3.8%	3.9%	5.5%	3.2%	3.5%	3.4%	3.8%	4.3%	***4.0%***	***4.0%***	Retained to Com Eq	***4.5%***
63%	62%	61%	60%	54%	67%	65%	67%	65%	61%	***63%***	***63%***	All Div'ds to Net Prof	***62%***

CAPITAL STRUCTURE as of 9/30/22
Total Debt $36349 mill. **Due in 5 Yrs** $12886 mill.
LT Debt $33647 mill. **LT Interest** $1067 mill.
Incl. $549.4 mill. securitized bonds. Incl. $500.7 mill. finance leases.
(LT interest earned: 3.2x)
Leases, Uncapitalized Annual rentals $119.6 mill.
Pension Assets-12/21 $5352.9 mill.
Oblig $5187.0 mill.
Pfd Stock None

Common Stock 513,863,678 shs.
as of 10/27/22
MARKET CAP: $48.9 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-2.2	- -	+3.0
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.3	+1.0	NA
Fixed Charge Cov. (%)	234	243	272

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	.5%	-1.5%	*3.5%*
"Cash Flow"	4.5%	5.0%	*5.5%*
Earnings	4.5%	4.0%	*6.5%*
Dividends	5.0%	6.0%	*6.0%*
Book Value	4.0%	3.5%	*6.0%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	4056	3573	4315	3616	15561
2020	3747	3494	4066	3610	14918
2021	4281	3826	4623	4061	16792
2022	4593	4640	5526	***3341***	***18100***
2023	***4800***	***4300***	***5150***	***4550***	***18800***

EARNINGS PER SHARE A

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.16	.93	1.48	.51	4.08
2020	1.00	1.05	1.50	.87	4.42
2021	1.15	1.15	1.59	1.07	4.96
2022	1.41	1.02	1.33	***1.24***	***5.00***
2023	***1.30***	***1.25***	***1.75***	***1.05***	***5.35***

QUARTERLY DIVIDENDS PAID B ■ †

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.62	.62	.62	.67	2.53
2019	.67	.67	.67	.70	2.71
2020	.70	.70	.70	.74	2.84
2021	.74	.74	.74	.78	3.00
2022	.78	.78	.78	.83	

BUSINESS: American Electric Power Company Inc. (AEP), through 10 operating utilities, serves 5.5 million customers in Arkansas, Kentucky, Indiana, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia, & West Virginia. Has a transmission subsidiary. Electric revenue breakdown: residential, 43%; commercial, 23%; industrial, 18%; wholesale, 10%; other, 6%. Sold commercial barge operation in '15. Generating sources not available. Fuel costs: 33% of revenues. '21 reported depreciation rates (utility): 2.6%-12.5%. Has 16,700 employees. Chairman, President & CEO: Nicholas K. Akins. COO: Lisa Barton. Incorporated: New York. Address: 1 Riverside Plaza, Columbus, Ohio 43215-2373. Telephone: 614-716-1000. Internet: www.aep.com.

American Electric Power will soon complete a divestiture, and the company is interested in shedding other assets. AEP expects to raise $1.45 billion from the sale of its Kentucky Power subsidiary. The motivation for the sale is the entity's lack of an adequate return on equity. The last remaining hurdle before the deal can go through is the approval of an application, which should be received by mid December. The transaction would then close by early January. The company has also started accepting initial bids for its 1,600-megawatt portfolio of nonregulated renewable-energy projects, either piecemeal or as a whole. Management is now moving on to the due diligence process with select bidders. It expects the process to close in the June quarter of 2023. Meanwhile, the company is conducting a strategic review of the retail business which it expects to complete in the first half of 2023. Following divestitures, AEP plans to expand its investments in regulated renewable-energy projects, which have less risk than nonutility assets, and electric transmission.

The company appears well positioned to meet or exceed its full-year guidance. American continues to realize above-forecast, weather-normalized load (the amount of electricity on the grid at any given time), which is now 2.6% above pre-pandemic levels. Year to date, residential, commercial, and industrial sales comparisons are up .3%, 3.8%, and 5.5%, respectively. This compares to the company's 2.9% (revised upward from 1.6%) retail sales forecast for 2022. The company should continue to benefit from rate relief, increased investment in its transmission business, and volume growth. Our $5.00 GAAP earnings estimate is within management's guidance (on a GAAP basis) of $4.97-$5.07 a share. At the analyst day in early October, the company established its 2023 earnings per share guidance range at $5.19-$5.39 and the long-term bottom line growth rate at 6%-7%.

The dividend yield of this top-quality stock is at the utility average. Total return potential is unspectacular for the next 18 months and Timeliness is average. Further, the recent quotation is just below our 2025-2027 Target Price Range.

Kevin Downing *December 9, 2022*

(A) Diluted EPS. Excl. nonrec. gains (losses): '06, (20¢); '07, (20¢); '08, 40¢; '10, (7¢); '11, 89¢; '12, (38¢); '13, (14¢); '16, ($2.99); '17, 26¢; '19, (20¢); gains (loss) from disc. ops.: '06, 2¢; '08, 3¢; '15, 58¢; '16, (1¢). Next earnings report due late Jan. **(B)** Div'ds paid early Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. † Shareholder invest. plan avail. **(C)** Incl. intang. In '21: $17.04/sh. **(D)** In mill. **(E)** Rate base: various. Rates allowed on com. eq.: 9.3%-10.9%; earned on avg. com. eq., '21: 11.6%. Regulatory Climate: Average.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	95

DUKE ENERGY NYSE-DUK

RECENT PRICE **93.18** | P/E RATIO **17.1** (Trailing: 17.7 Median: 18.0) | RELATIVE P/E RATIO **1.11** | DIV'D YLD **4.3%** | **VALUE LINE**

TIMELINESS 3 Raised 5/20/22
SAFETY 2 New 6/1/07
TECHNICAL 2 Lowered 11/4/22
BETA .85 (1.00 = Market)

18-Month Target Price Range

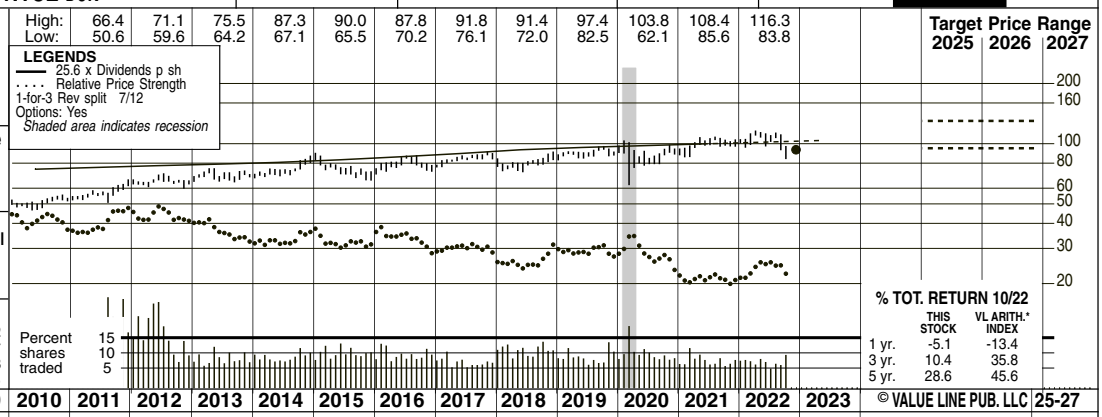
Low-High	Midpoint (% to Mid)
$88-$134	$111 (20%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	130	(+40%)	*12%*
Low	95	(Nil)	*5%*

Institutional Decisions

	4Q2021	1Q2022	2Q2022
to Buy	934	942	877
to Sell	627	651	688
Hld's(000)	484677	487269	491735



2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
25.32	30.24	31.15	29.18	32.22	32.63	27.88	34.84	33.84	34.10	32.49	33.66	33.73	34.21	31.04	32.64	*35.05*	*36.05*	Revenues per sh	*37.90*
7.86	8.11	7.34	7.58	8.49	8.68	6.80	8.56	9.11	9.40	9.20	10.01	11.05	12.12	12.04	12.60	*13.25*	*14.00*	"Cash Flow" per sh	*16.00*
2.76	3.60	3.03	3.39	4.02	4.14	3.71	3.98	4.13	4.10	3.71	4.22	4.72	5.06	5.12	5.24	*5.45*	*5.75*	Earnings per sh A	*6.50*
- -	2.58	2.70	2.82	2.91	2.97	3.03	3.09	3.15	3.24	3.36	3.49	3.64	3.75	3.82	3.90	*3.98*	*4.06*	Div'd Decl'd per sh B ■	*4.30*
8.07	7.43	10.35	9.85	10.84	9.80	7.81	7.83	7.62	9.83	11.29	11.50	12.91	15.17	12.88	12.63	*16.00*	*16.75*	Cap'l Spending per sh	*16.75*
62.30	50.40	49.51	49.85	50.84	51.14	58.04	58.54	57.81	57.74	58.62	59.63	60.27	61.20	59.82	61.55	*62.75*	*64.50*	Book Value per sh C	*70.00*
418.96	420.62	423.96	436.29	442.96	445.29	704.00	706.00	707.00	688.00	700.00	700.00	727.00	733.00	769.00	769.00	*770.00*	*770.00*	Common Shs Outst'g D	*770.00*
- -	16.1	17.3	13.3	12.7	13.8	17.5	17.4	17.9	18.2	21.3	19.9	17.0	17.7	17.1	18.9	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*17.0*
- -	.85	1.04	.89	.81	.87	1.11	.98	.94	.92	1.12	1.00	.92	.94	.88	1.02			Relative P/E Ratio	*.95*
- -	4.4%	5.2%	6.2%	5.7%	5.2%	4.7%	4.4%	4.3%	4.3%	4.3%	4.2%	4.5%	4.2%	4.4%	3.9%			Avg Ann'l Div'd Yield	*3.9%*
						19624	24598	23925	23459	22743	23565	24521	25079	23868	25097	*27000*	*27750*	Revenues ($mill)	*29200*
						2136.0	2813.0	2934.0	2854.0	2560.0	2963.0	3339.0	3747.0	3878.0	4133.0	*4200*	*4500*	Net Profit ($mill)	*5040*
						30.2%	32.6%	30.6%	32.2%	31.0%	30.4%	14.1%	12.7%	.3%	5.1%	*10.0%*	*9.0%*	Income Tax Rate	*9.0%*
						22.3%	8.8%	7.2%	9.2%	11.7%	12.3%	11.4%	8.0%	6.9%	5.9%	*8.0%*	*7.0%*	AFUDC % to Net Profit	*7.0%*
						47.0%	48.0%	47.7%	48.6%	52.6%	54.0%	53.8%	54.0%	53.7%	55.1%	*56.5%*	*58.5%*	Long-Term Debt Ratio	*61.0%*
						52.9%	52.0%	52.3%	51.4%	47.4%	46.0%	46.2%	44.1%	44.4%	43.1%	*42.0%*	*40.0%*	Common Equity Ratio	*37.5%*
						77307	79482	78088	77222	86609	90774	94940	101807	103589	109744	*115150*	*124525*	Total Capital ($mill)	*144100*
						68558	69490	70046	75709	82520	86391	91694	102127	106782	111408	*117725*	*124375*	Net Plant ($mill)	*141100*
						3.6%	4.6%	4.8%	4.8%	4.0%	4.3%	4.6%	4.7%	4.8%	4.8%	*4.5%*	*4.5%*	Return on Total Cap'l	*4.5%*
						5.2%	6.8%	7.2%	7.2%	6.2%	7.1%	7.6%	8.0%	8.1%	8.4%	*8.5%*	*9.0%*	Return on Shr. Equity	*9.0%*
						5.2%	6.8%	7.2%	7.2%	6.2%	7.1%	7.6%	8.3%	8.2%	8.5%	*8.5%*	*9.0%*	Return on Com Equity E	*9.0%*
						.9%	1.5%	1.7%	1.5%	.6%	1.2%	2.0%	2.4%	2.3%	1.9%	*2.5%*	*2.5%*	Retained to Com Eq	*3.0%*
						82%	78%	76%	79%	91%	83%	74%	71%	73%	78%	*76%*	*73%*	All Div'ds to Net Prof	*68%*

CAPITAL STRUCTURE as of 6/30/22
Total Debt $70193 mill. **Due in 5 Yrs** $19536 mill.
LT Debt $63147 mill. **LT Interest** $2206 mill.
Incl. $915 mill. finance leases.
(LT interest earned: 2.7x)
Leases, Uncapitalized Annual rentals $225 mill.
Pension Assets-12/21 $9235 mill.
Oblig $8207 mill.
Pfd Stock $1962 mill. **Pfd Div'd** $107 mill.
40 mill. shs. 5.75%, cum., $25 liq. value, redeemable at $25.50 prior to 6/15/24; 1 mill. shs. 4.875%, cum., $1000 liq. value.
Common Stock 769,968,724 shs. **as of 7/31/22**
MARKET CAP: $84.6 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-.9	-2.3	+2.0
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (avg.)	NA	NA	NA
Fixed Charge Cov. (%)	233	183	209

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	.5%	-.5%	*2.5%*
"Cash Flow"	4.0%	5.0%	*5.0%*
Earnings	3.0%	4.5%	*5.0%*
Dividends	3.0%	3.5%	*2.0%*
Book Value	2.0%	1.0%	*2.5%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	6163	5873	6940	6103	25079
2020	5949	5421	6721	5777	23868
2021	6150	5758	6951	6238	25097
2022	7132	6685	*7255*	*5928*	*27000*
2023	*7250*	*6750*	*7375*	*6375*	*27750*

EARNINGS PER SHARE A

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.24	1.12	1.79	.91	5.06
2020	1.14	1.08	1.87	1.03	5.12
2021	1.26	1.15	1.88	.94	5.24
2022	1.30	1.14	*1.86*	*1.15*	*5.45*
2023	*1.30*	*1.20*	*2.00*	*1.10*	*5.75*

QUARTERLY DIVIDENDS PAID B ■

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.89	.89	.9275	.9275	3.64
2019	.9275	.9275	.945	.945	3.75
2020	.945	.945	.965	.965	3.82
2021	.965	.965	.985	.985	3.90
2022	.985	.985	1.005		

BUSINESS: Duke Energy Corporation is a holding company for utilities with 7.6 mill. elec. customers in NC, FL, IN, SC, OH, & KY, and 1.6 mill. gas customers in OH, KY, NC, SC, and TN. Owns independent power plants & has 25% stake in National Methanol in Saudi Arabia. Acq'd Progress Energy 7/12; Piedmont Natural Gas 10/16; discontinued most int'l ops. in '16. Elec. rev. breakdown: residential, 45%; commercial, 28%; industrial, 13%; other, 14%. Generating sources: gas, 32%; nuclear, 30%; coal, 18%; other, 1%; purchased, 19%. Fuel costs: 28% of revs. '21 reported deprec. rate: 2.9%. Has 27,600 employees. Chairman, President & CEO: Lynn J. Good. Inc.: DE. Address: 550 South Tryon St., Charlotte, NC 28202-1803. Tel.: 704-382-3853. Internet: www.duke-energy.com.

Duke Energy has a number of rate cases pending. In North Carolina, Duke Energy Progress requested a boost of $326 million (8.5%) in 2023, $151 million (3.9%) in 2024, and $138 million (3.6%) in 2025. In South Carolina, Duke Energy Progress proposed its first base rate case in four years, and expects rates to go into effect in early 2023. In Ohio, the utility is seeking a $55 million (3%) hike, as the rate case hearing nears a conclusion. Adjusted second-quarter earnings of $1.14 a share, slightly outperformed our call of $1.10. Our 2022 full-year estimate remains at $5.45 a share. Management reaffirmed a range of $5.30 to $5.60, and a long-term earnings growth rate of 5% to 7% through 2026. Rate relief and strong retail volumes were the main drivers to the bottom line in the second period. Volume growth increased 2.6% year over year, which is higher than 2019 levels.

We look for a strong earnings performance in 2023, near the company's growth target of between 5% and 7%. Higher electric volumes should continue, and Duke Energy raised its load growth prediction to 1.5%-2% from 1.5%. The utility is estimating cost mitigation of $200 million starting in 2023, due to rising interest rates and inflation.

The company is very focused on carbon reduction and the development of clean and renewable energy projects. Currently, the utility has 5,000 megawatts of Commericial wind, solar, and battery projects, ranking it within the top-10 largest renewable companies in the United States. By 2035, the company intends to reach 30,000 megawatts of renewable energy. Duke plans to invest $145 billion over the next 10 years and achieve net-zero carbon emissions by 2050 in its clean energy transition. Management expects carbon emission reduction to exceed 50% by 2030, and 80% by 2040.

The stock has dropped 20% in value since our August report, alongside losses by most of its peers over that time due to rising interest rates. Despite the stock's price reduction, its 18-month and 3- to 5-year capital appreciation potential does not stand out. Meanwhile, this issue is ranked 3 (Average) for Timeliness.

Zachary J. Hodgkinson November 11, 2022

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	45
Earnings Predictability	100

(A) Dil. EPS. Excl. net nonrec. losses: '12, 64¢; '13, 22¢; '14, 59¢; '15, 5¢; '16, 60¢; '18, 96; '20, $3.40; '21, 30¢; 1Q22, 22¢; net nonrec gain: '17, 14¢. 2021 EPS don't sum to annual due to rounding. Next egs. due early Feb. **(B)** Div'ds paid mid-Mar., June, Sept., & Dec. ■ Div'd reinv. plan avail. **(C)** Incl. intang. In '21: $41.34/sh. **(D)** In mill., adj. for rev. split. **(E)** Rate base: Net orig. cost. Rate all'd on com. eq. in '21 in NC: 9.6%; in '19 in SC: 9.5%; in '20 in FL: 9.5%-11.5%; in '20 in IN: 9.7%. Reg. Clim.: NC, SC Avg.; OH, IN Above Avg.

EDISON INTERNAT'L NYSE-EIX

RECENT PRICE **57.85** | P/E RATIO **12.8** (Trailing: 23.2 Median: 17.0) | RELATIVE P/E RATIO **0.87** | DIV'D YLD **4.8%** | **VALUE LINE**

TIMELINESS 4 Lowered 9/23/22
SAFETY 3 Lowered 11/23/18
TECHNICAL 2 Raised 9/23/22
BETA .95 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$57-$95	$76 (30%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	120	(+105%)	*23%*
Low	80	(+40%)	*12%*

Institutional Decisions

	4Q2021	1Q2022	2Q2022
to Buy	356	323	368
to Sell	252	291	254
Hld's(000)	335565	332086	333217

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
High:	41.6	48.0	54.2	68.7	69.6	78.7	83.4	71.0	76.4	78.9	68.6	73.3								
Low:	32.6	39.6	44.3	44.7	55.2	58.0	62.7	45.5	53.4	43.6	53.9	56.6								
	38.74	40.25	43.31	37.98	38.09	39.16	36.41	38.61	41.17	35.37	36.43	37.81	38.85	34.11	35.83	39.18	*42.65*	*43.35*	Revenues per sh	*47.45*
	7.25	7.60	8.08	7.96	8.41	9.03	9.63	8.80	9.95	10.35	10.43	11.03	4.69	9.15	7.94	8.58	*11.05*	*11.65*	"Cash Flow" per sh	*13.55*
	3.28	3.32	3.68	3.24	3.35	3.23	4.55	3.78	4.33	4.15	3.94	4.51	d1.26	3.98	1.72	2.00	*4.50*	*4.85*	Earnings per sh [A]	*6.25*
	1.10	1.18	1.23	1.25	1.27	1.29	1.31	1.37	1.48	1.73	1.98	2.23	2.43	2.48	2.58	2.69	*2.84*	*3.00*	Div'd Decl'd per sh [B] ■	*3.55*
	7.78	8.67	8.67	10.07	13.94	14.76	12.73	11.05	11.99	12.97	11.46	11.75	13.84	13.47	14.47	14.47	*14.90*	*15.20*	Cap'l Spending per sh	*16.65*
	23.66	25.92	29.21	30.20	32.44	30.86	28.95	30.50	33.64	34.89	36.82	35.82	32.10	36.75	37.08	36.57	*37.30*	*39.55*	Book Value per sh [C]	*47.85*
	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	325.81	361.99	378.91	380.38	*382.00*	*382.00*	Common Shs Outst'g [D]	*390.00*
	13.0	16.0	12.4	9.7	10.3	11.8	9.7	12.7	13.0	14.8	17.9	17.2	- -	16.7	34.9	29.7	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*16.0*
	.70	.85	.75	.65	.66	.74	.62	.71	.68	.75	.94	.87	- -	.89	1.79	1.63			Relative P/E Ratio	*.90*
	2.6%	2.2%	2.7%	4.0%	3.7%	3.4%	3.0%	2.8%	2.6%	2.8%	2.8%	2.9%	3.8%	3.7%	4.3%	4.5%			Avg Ann'l Div'd Yield	*3.6%*
							11862	12581	13413	11524	11869	12320	12657	12347	13578	14905	*16300*	*16550*	Revenues ($mill)	*18500*
							1594.0	1344.0	1539.0	1480.0	1422.0	1603.0	d290.0	1477.0	775.0	925.0	*1720*	*1855*	Net Profit ($mill)	*2440*
							14.3%	25.2%	22.4%	6.6%	11.1%	5.0%	- -	- -	- -	- -	*5.0%*	*5.0%*	Income Tax Rate	*5.0%*
							8.5%	7.8%	5.8%	8.0%	6.8%	7.2%	- -	11.1%	22.5%	18.5%	*10.0%*	*9.0%*	AFUDC % to Net Profit	*7.0%*
							45.2%	45.7%	44.1%	45.0%	41.8%	45.6%	53.6%	53.5%	55.2%	57.6%	*57.5%*	*58.5%*	Long-Term Debt Ratio	*61.5%*
							46.2%	46.2%	47.2%	46.7%	49.2%	45.8%	38.3%	39.9%	39.5%	33.2%	*32.0%*	*32.0%*	Common Equity Ratio	*32.0%*
							20422	21516	23216	24352	24362	25506	27284	33360	35581	41959	*44500*	*47000*	Total Capital ($mill)	*60500*
							30273	30455	32981	35085	37000	39050	41348	44285	47839	50700	*53900*	*57500*	Net Plant ($mill)	*66750*
							8.9%	7.3%	7.7%	7.1%	6.9%	7.3%	.1%	5.6%	3.4%	3.3%	*6.0%*	*5.5%*	Return on Total Cap'l	*5.5%*
							14.2%	11.5%	11.9%	11.1%	10.0%	11.6%	NMF	9.5%	4.9%	5.2%	*11.5%*	*11.0%*	Return on Shr. Equity	*11.5%*
							15.9%	12.5%	13.0%	12.0%	10.8%	12.7%	NMF	10.2%	4.6%	5.5%	*13.0%*	*13.0%*	Return on Com Equity [E]	*13.0%*
							11.4%	8.1%	8.8%	7.2%	5.6%	6.6%	NMF	4.1%	NMF	NMF	*6.5%*	*5.5%*	Retained to Com Eq	*6.0%*
							32%	40%	37%	44%	53%	52%	NMF	63%	NMF	125%	*63%*	*62%*	All Div'ds to Net Prof	*57%*

% TOT. RETURN 9/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	6.5	-18.2
3 yr.	-14.4	24.1
5 yr.	-9.8	32.9

CAPITAL STRUCTURE as of 6/30/22
Total Debt $27318 mill. **Due in 5 Yrs** $9600 mill.
LT Debt $25143 mill. **LT Interest** $990 mill.
(LT interest earned: 3.1x)
Leases, Uncapitalized Annual rentals $623 mill.
Pension Assets-12/21 $4296 mill.
Oblig $4171 mill.
Pfd Stock $3878 mill. **Pfd Div'd** $211 mill.
350,000 sh. 6.25%, $1000 liq. value; 638,020 sh. 5.0%-5.75%, $2500 liq. value; 1,250,000 sh. 5.375%, 750,000 sh. 5%, $1000 liq. value, all cum.
Common Stock 381,431,985 shs.
as of 7/29/22
MARKET CAP: $22.1 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-2.7	+.7	-3.9
Avg. Indust. Use (MWH)	657	589	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	22009	23133	21190
Annual Load Factor (%)	49.6	46.7	52.7
% Change Customers (yr-end)	+.5	+.6	+.3
Fixed Charge Cov. (%)	172	NMF	113

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-.5%	-.5%	*4.5%*
"Cash Flow"	- -	-3.5%	*8.0%*
Earnings	-2.5%	-9.0%	*16.0%*
Dividends	7.5%	8.5%	*5.5%*
Book Value	1.5%	1.0%	*4.5%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2824	2812	3741	2970	12347
2020	2790	2987	4644	3157	13578
2021	2960	3315	5299	3331	14905
2022	3968	4008	*5000*	*3324*	*16300*
2023	*3425*	*3725*	*5675*	*3725*	*16550*

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.64	1.57	1.35	.45	3.98
2020	.50	.85	d.76	1.13	1.72
2021	.68	.84	d.90	1.38	2.00
2022	1.07	.94	*1.65*	*.84*	*4.50*
2023	*1.10*	*1.00*	*1.70*	*1.05*	*4.85*

QUARTERLY DIVIDENDS PAID [B] ■

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.605	.605	.605	.605	2.42
2019	.6125	.6125	.6125	.6125	2.45
2020	.6375	.6375	.6375	.6375	2.55
2021	.6625	.6625	.6625	.6625	2.65
2022	.70	.70	.70	.70	

BUSINESS: Edison International (formerly SCECorp) is a holding company for Southern California Edison Company (SCE), which supplies electricity to 5.2 mill. customers in a 50,000-sq.-mi. area in central, coastal, & southern CA (excl. Los Angeles & San Diego). Edison Energy is an energy svcs. co. Disc. Edison Mission Energy (independent power producer) in '12. Elec. rev. breakdown: residential, 43%; commercial, 45%; industrial, 3%; other, 9%. Generating sources: nuclear, 8%; gas, 3%; hydro, 3%; purch., 86%. Power costs: 37% of revs. '21 reported depr. rate: 3.7%. Has 13,000 empls. Chairman: William P. Sullivan. Pres. & CEO: Pedro J. Pizzaro. Inc.: CA. Address: 2244 Walnut Grove Ave., P.O. Box 976, Rosemead, CA 91770. Tel.: 626-302-2222. Web: www.edison.com.

Edison International's earnings are set for a sharp rise in 2022. In 2018, wildfires and mudslides wreaked havoc on the company's bottom line. The claims tied to these disasters then landed on the books in 2020 and 2021. For 2022, we expect a much cleaner ledger, which should result in core share net climbing to the $4.50 level. Looking ahead to next year, we look for something in line with the in-house goal of 5% to 7% earnings growth, so we are reiterating our $4.85 target. Of course, there are potential hurdles to such gains, most notably the California Public Utilities Commission (CPUC). This entity could potentially trim Edison's 2022 ROE from 10.3% to 9.72% retroactively, but at this time we still do not think this will happen, given the current market conditions. Once this proceeding is completed, additional regulatory decisions will be made on 2023 through 2025. The rulings of the CPUC will have a noticeable impact on year-over-year earnings, and for now we view the regulatory climate here as average, so we are not factoring in any shakeups in the ROE path.

Doing business in California is expensive, and the electricity industry is particularly cost heavy. The state's size and geography inflate fixed operating costs. More specifically, generation, maintenance, distribution, wildfire-related expenditures, and public programs are all costly. EIX bears some of this burden, while a good chunk is passed onto residents. The average Californian pays 28% more annually for their electric than the national average.

Investments by Edison in wildfire risk mitigation will continue. In the last three and a half years, 3,500 circuit miles of bare wire were replaced with covered conductor, and in the next couple of years a 1,200 mile pace is expected. With that, capital spending and long-term debt should head higher in the coming years.

This utility's dividend yield is a full percentage point above the industry's average. The payout is running higher as investor fears about California heightened during a September heat wave. Elsewhere, this untimely selection also has slightly below average readings for the 18-month window and for the pull to 2025-2027.

Erik M. Manning *October 21, 2022*

(A) Dil. EPS. Excl. nonrec. gains (losses): '09, (64¢); '10, 54¢; '11, ($3.33); '13, ($1.12); '15, ($1.18); '17, ($1.37); '18, (15¢); '19, (21¢); '20, 25¢; gains (loss) from disc. ops.: '12, ($5.11); '13, 11¢; '14, 57¢; '15, 11¢; '18, 10¢. '19 EPS don't sum due to change in shs. Next earnings report due early November. **(B)** Div'ds paid late Jan., Apr., July, & Oct. ■ Div'd reinv. plan avail. **(C)** Incl. def'd chgs. In '21: $20.14/sh. **(D)** In mill. **(E)** Rate base: net orig. cost. Rate all'd on com. eq. in '20: 10.3%; earned on avg. com. eq., '21: 5.4%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	75
Price Growth Persistence	35
Earnings Predictability	10

ENTERGY CORP. NYSE-ETR

RECENT PRICE 113.25 | P/E RATIO 17.0 (Trailing: 18.1 Median: 14.0) | RELATIVE P/E RATIO 1.04 | DIV'D YLD 3.8% | VALUE LINE

TIMELINESS 3 Raised 9/2/22
SAFETY 2 Raised 12/13/19
TECHNICAL 4 Lowered 12/9/22
BETA .95 (1.00 = Market)

18-Month Target Price Range

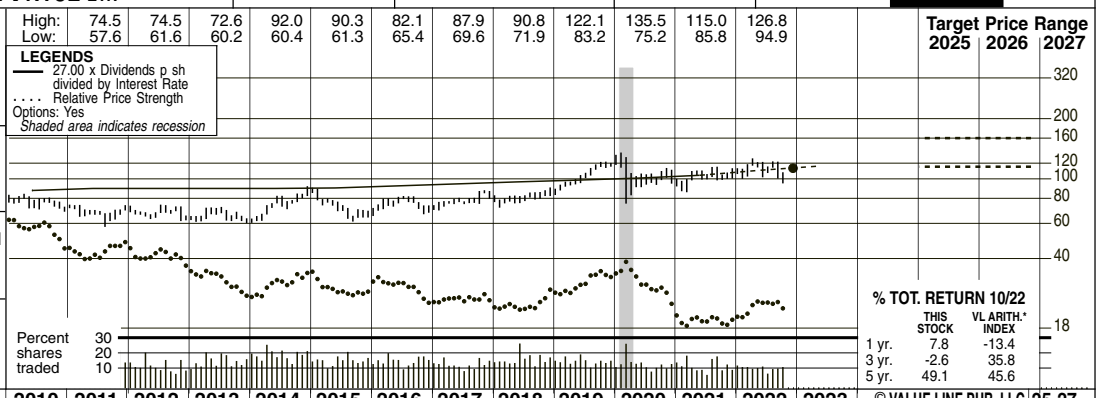
Low-High	Midpoint (% to Mid)
$99-$158	$129 (15%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	160	(+40%)	*12%*
Low	115	(Nil)	*5%*

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	327	348	348
to Sell	281	260	258
Hld's(000)	179128	184330	184841



2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
53.94	59.47	69.15	56.82	64.27	63.67	57.94	63.86	69.71	64.54	60.55	61.35	58.23	54.63	50.51	57.95	*63.10*	*56.45*	Revenues per sh	*61.50*
10.69	11.73	12.89	13.29	16.54	17.53	15.98	16.25	17.68	17.71	18.72	16.70	16.50	17.19	18.21	17.90	*17.75*	*17.95*	"Cash Flow" per sh	*20.50*
5.36	5.60	6.20	6.30	6.66	7.55	6.02	4.96	5.77	5.81	6.88	5.19	5.88	6.30	6.90	6.87	*6.65*	*6.80*	Earnings per sh A	*8.50*
2.16	2.58	3.00	3.00	3.24	3.32	3.32	3.32	3.32	3.34	3.42	3.50	3.58	3.66	3.74	3.86	*4.10*	*4.30*	Div'd Decl'd per sh B ■ †	*5.10*
9.44	10.29	13.92	12.99	13.33	15.21	18.18	15.73	14.82	16.79	17.28	22.07	22.45	21.72	24.52	30.86	*18.15*	*19.00*	Cap'l Spending per sh	*19.75*
40.45	40.71	42.07	45.54	47.53	50.81	51.73	54.00	55.83	51.89	45.12	44.28	46.78	51.34	54.56	57.42	*60.00*	*63.55*	Book Value per sh C	*74.00*
202.67	193.12	189.36	189.12	178.75	176.36	177.81	178.37	179.24	178.39	179.13	180.52	189.06	199.15	200.24	202.65	*206.00*	*209.00*	Common Shs Outst'g D	*214.00*
14.3	19.3	16.6	12.0	11.6	9.1	11.2	13.2	12.9	12.5	10.9	15.0	13.8	16.5	15.3	15.0	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*16.0*
.77	1.02	1.00	.80	.74	.57	.71	.74	.68	.63	.57	.75	.75	.88	.79	.80			Relative P/E Ratio	*.90*
2.8%	2.4%	2.9%	4.0%	4.2%	4.9%	4.9%	5.1%	4.5%	4.6%	4.6%	4.5%	4.4%	3.5%	3.6%	3.7%			Avg Ann'l Div'd Yield	*3.7%*
10302	11391	12495	11513	10846	11074	11009	10879	10114	11743	*13000*	*11800*	Revenues ($mill)	*13150*
1091.9	904.5	1060.0	1061.2	1249.8	950.7	1092.1	1258.2	1406.7	1402.8	*1370*	*1420*	Net Profit ($mill)	*1845*
13.0%	26.7%	37.8%	2.2%	11.3%	1.8%	NMF	NMF	NMF	16.1%	*23.0%*	*23.0%*	Income Tax Rate	*23.0%*
11.9%	10.1%	9.3%	7.4%	8.1%	14.7%	17.5%	16.7%	12.2%	7.1%	*8.0%*	*8.0%*	AFUDC % to Net Profit	*7.0%*
55.8%	55.1%	54.9%	57.8%	63.6%	63.6%	63.2%	62.0%	65.5%	67.6%	*66.5%*	*66.5%*	Long-Term Debt Ratio	*66.0%*
42.9%	43.6%	43.8%	40.8%	35.5%	35.5%	35.9%	37.1%	33.7%	31.7%	*32.5%*	*33.0%*	Common Equity Ratio	*33.5%*
21432	22109	22842	22714	22777	22528	24602	27557	32386	36733	*38050*	*40200*	Total Capital ($mill)	*47300*
27299	27882	28723	27824	27921	29664	31974	35183	38853	42244	*43750*	*45425*	Net Plant ($mill)	*50800*
6.4%	5.4%	6.0%	6.0%	6.9%	5.7%	5.8%	5.9%	5.6%	4.8%	*3.0%*	*4.5%*	Return on Total Cap'l	*5.0%*
11.5%	9.1%	10.3%	11.1%	15.1%	11.6%	12.0%	12.0%	12.6%	11.6%	*9.5%*	*10.5%*	Return on Shr. Equity	*11.5%*
11.6%	9.2%	10.4%	11.2%	15.2%	11.7%	12.2%	12.1%	12.7%	11.9%	*9.5%*	*10.5%*	Return on Com Equity E	*11.5%*
5.2%	3.0%	4.4%	4.8%	7.7%	3.9%	4.9%	5.2%	5.9%	5.2%	*3.5%*	*4.0%*	Retained to Com Eq	*4.5%*
56%	68%	58%	58%	50%	68%	61%	58%	55%	57%	*62%*	*64%*	All Div'ds to Net Prof	*60%*

CAPITAL STRUCTURE as of 9/30/22
Total Debt $27606 mill. **Due in 5 Yrs** $11117 mill.
LT Debt $24635 mill. **LT Interest** $824.0 mill.
Incl. $54.7 mill. of securitization bonds.
(LT interest earned: 2.8x)
Leases, Uncapitalized Annual rentals $65.3 mill.
Pension Assets-12/21 $6993.1 mill.
Oblig $8409.6 mill.
Pfd Stock $254.4 mill. **Pfd Div'd** $18.3 mill.
200,000 shs. 6.25%-7.5%, $100 par; 250,000 shs. 8.75%, 1.4 mill. shs. 5.375%; all cum., without sinking fund.
Common Stock 203,483,660 shs. **as of 10/31/22**
MARKET CAP: $23.0 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-1.4	-4.1	+3.2
Avg. Indust. Use (MWH)	1070	1017	1015
Avg. Indust. Revs. per KWH(¢)	5.24	4.95	5.91
Capacity at Peak (Mw)	23887	25665	NA
Peak Load, Summer (Mw)	21598	21340	NA
Annual Load Factor (%)	64	62	NA
% Change Customers (yr-end)	+.8	+1.0	+1.0
Fixed Charge Cov. (%)	165	202	243

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-1.0%	-3.5%	*2.0%*
"Cash Flow"	1.0%	-.5%	*2.5%*
Earnings	- -	1.5%	*4.0%*
Dividends	1.5%	2.0%	*5.0%*
Book Value	1.5%	1.5%	*5.0%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2610	2666	3141	2462	10879
2020	2427	2413	2904	2370	10114
2021	2845	2822	3353	2723	11743
2022	2878	3395	4219	*2508*	*13000*
2023	*2950*	*2850*	*3250*	*2750*	*11800*

EARNINGS PER SHARE A

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.32	1.22	1.82	1.94	6.30
2020	.59	1.79	2.59	1.93	6.90
2021	1.66	1.30	2.63	1.28	6.87
2022	1.36	1.78	2.84	*.67*	*6.65*
2023	*1.40*	*1.75*	*2.90*	*.75*	*6.80*

QUARTERLY DIVIDENDS PAID B ■ †

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.89	.89	.89	.91	3.58
2019	.91	.91	.91	.93	3.66
2020	.93	.93	.93	.95	3.74
2021	.95	.95	.95	1.01	3.86
2022	1.01	1.01	1.01	1.07	

BUSINESS: Entergy Corporation supplies electricity to 3 million customers through subsidiaries in Arkansas, Louisiana, Mississippi, Texas, and New Orleans (regulated separately from Louisiana). Distributes gas to 206,000 customers in Louisiana. Is selling its last nonutility nuclear unit (shut down 5/22). Electric revenue breakdown: residential, 37%; commercial, 24%; industrial, 27%; other, 12%. Generating sources: gas, 46%; nuclear, 30%; coal, 6%; purchased, 18%. Fuel costs: 32% of revenues. '21 reported depreciation rate: 2.7%. Has 12,400 employees. Chairman & CEO: Leo P. Denault. Incorporated: Delaware. Address: 639 Loyola Avenue, P.O. Box 61000, New Orleans, Louisiana 70161. Telephone: 504-576-4000. Internet: www.entergy.com.

Entergy Corp. recorded solid third-quarter results. Revenues expanded to $4.2 billion, aided by strong growth across its electric services business and higher energy prices. Positives included healthy demand from industrial companies, while population growth across the southern United States was positive. The company also benefited from several rate cases being approved, allowing for more recoveries, and a few projects were placed into service. Still, costs rose at a quick rate, especially those related to fuel costs, while operational maintenance was much higher. Overall, adjusted earnings rose to $2.84 per share during the quarter. The fourth-quarter performance will likely be lackluster as the company faces tough comparisons from 2021, which had cooler-than-usual weather. It exited some nonregulated nuclear operations in Michigan over the past year, and it sold some shares to fund capital expenditures. We estimate adjusted earnings will reach $0.67 per share in the final quarter of 2022.

The long-term outlook is decent. Entergy should gain from population and industrial growth across its coverage area. Additionally, it has filed for several rate cases, including for Entergy New Orleans and Entergy Texas, with a decision on the latter due in the second quarter of 2023. Additionally, the company has been investing in renewable energy projects that will come online in the years ahead, helping to bolster revenues, and regulators could approve more. Costs for fuel and maintenance will likely increase with the added operations. The company has been funding capital expenditures with debt and equity sales, which should limit profit-per-share gains. Bad-debt expenses may well pick up if the economy slows further. We project adjusted earnings per share of $6.80 in 2023 and $8.50 in 2025-2027.

The board raised the quarterly dividend by 6% to $1.07. This payout remains well covered by profits and should expand steadily in the years ahead.

Shares of Entergy Corp. are neutrally ranked for Timeliness. This stock has a good dividend yield and long-term upside potential is subpar. Overall, we think this is best suited for conservative income-seeking accounts.

John E. Seibert III *December 9, 2022*

(A) Diluted EPS. Excl. nonrec. losses: '12, $1.26; '13, $1.14; '14, 56¢; '15, $6.99; '16, $10.14; '17, $2.91; '18, $1.25; '21, $1.33; '22, $1.19. Next earnings report due early Feb. **(B)** Div'ds historically paid in early Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. **(C)** Incl. deferred charges. In '21: $35.95/sh. **(D)** In mill. **(E)** Rate base: Net original cost. Allowed ROE (blended): 9.95%; earned on avg. com. eq., '21: 12.1%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	45
Earnings Predictability	70

EVERGY, INC. NYSE-EVRG

RECENT PRICE 58.69 | P/E RATIO 16.4 (Trailing: 17.0 Median: NMF) | RELATIVE P/E RATIO 1.01 | DIV'D YLD 4.2% | VALUE LINE

TIMELINESS 3 Raised 9/2/22
SAFETY 2 New 9/14/18
TECHNICAL 3 Lowered 11/18/22
BETA .90 (1.00 = Market)

18-Month Target Price Range

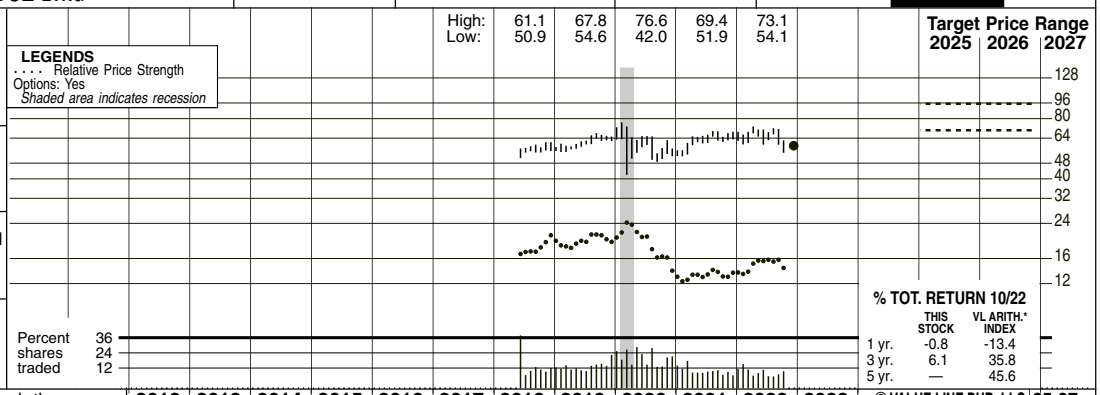
Low-High	Midpoint (% to Mid)
$53-$88	$71 (20%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	95	(+60%)	*16%*
Low	70	(+20%)	*8%*

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	284	304	305
to Sell	270	252	250
Hld's(000)	196288	194242	193700



Evergy, Inc. was formed through the merger of Great Plains Energy and Westar Energy in June of 2018. Great Plains Energy holders received .5981 of a share of Evergy for each of their shares, and Westar Energy holders received one share of Evergy for each of their shares. The merger was completed on June 4, 2018. Shares of Evergy began trading on the New York Stock Exchange one day later.

CAPITAL STRUCTURE as of 9/30/22
Total Debt $11664 mill. **Due in 5 Yrs** $4388.2 mill.
LT Debt $9197.2 mill. **LT Interest** $305.5 mill.
Incl. $40.9 mill. finance leases.
(LT interest earned: 3.8x)

Leases, Uncapitalized Annual rentals $18.8 mill.

Pension Assets-12/21 $1714.7 mill.
Oblig $2561.7 mill.

Pfd Stock None

Common Stock 229,536,385 shs.
as of 10/31/22
MARKET CAP: $13.5 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	NA	-3.9	+3.1
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	7.25	7.14	6.94
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	305	286	350

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	--	--	*2.5%*
"Cash Flow"	--	--	*5.0%*
Earnings	--	--	*7.5%*
Dividends	--	--	*7.0%*
Book Value	--	--	*3.5%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1217	1222	1578	1131	5148
2020	1117	1185	1517	1094	4913
2021	1612	1236	1617	1122	5587
2022	1224	1447	1909	*1120*	*5700*
2023	*1225*	*1450*	*1900*	*1225*	*5800*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.39	.57	1.56	.28	2.79
2020	.31	.59	1.60	.22	2.72
2021	.84	.81	1.95	.23	3.83
2022	.53	.84	1.86	*.32*	*3.55*
2023	*.60*	*.80*	*2.05*	*.30*	*3.75*

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.40	.40	.46	.475	1.74
2019	.475	.475	.475	.505	1.93
2020	.505	.505	.505	.535	2.05
2021	.535	.535	.535	.5725	2.18
2022	.5725	.5725	.6125		

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
	--	--	--	--	--	--	16.75	22.71	21.66	24.36	*24.80*	*25.20*	Revenues per sh	*26.50*
	--	--	--	--	--	--	4.89	7.18	7.06	8.18	*8.05*	*8.40*	"Cash Flow" per sh	*10.00*
	--	--	--	--	--	--	2.50	2.79	2.72	3.83	*3.55*	*3.75*	Earnings per sh A	*4.75*
	--	--	--	--	--	--	1.74	1.93	2.05	2.18	*2.33*	*2.48*	Div'd Decl'd per sh B ■	*3.05*
	--	--	--	--	--	--	4.19	5.34	6.88	8.60	*8.60*	*9.20*	Cap'l Spending per sh	*9.50*
	--	--	--	--	--	--	39.28	37.82	38.50	40.32	*41.40*	*42.70*	Book Value per sh C	*47.50*
	--	--	--	--	--	--	255.33	226.64	226.84	229.30	*230.00*	*230.00*	Common Shs Outst'g D	*230.00*
	--	--	--	--	--	--	22.7	21.8	21.7	16.2	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*17.5*
	--	--	--	--	--	--	1.23	1.16	1.11	.87			Relative P/E Ratio	*.95*
	--	--	--	--	--	--	3.1%	3.2%	3.5%	3.5%			Avg Ann'l Div'd Yield	*3.7%*
	--	--	--	--	--	--	4275.9	5147.8	4913.4	5586.7	*5700*	*5800*	Revenues ($mill)	*6100*
	--	--	--	--	--	--	535.8	669.9	618.3	879.7	*835*	*880*	Net Profit ($mill)	*1115*
	--	--	--	--	--	--	9.8%	12.6%	14.1%	11.7%	*9.0%*	*9.0%*	Income Tax Rate	*9.0%*
	--	--	--	--	--	--	2.5%	2.5%	5.5%	5.0%	*5.0%*	*6.0%*	AFUDC % to Net Profit	*5.0%*
	--	--	--	--	--	--	40.0%	50.6%	51.3%	50.1%	*51.5%*	*51.5%*	Long-Term Debt Ratio	*53.5%*
	--	--	--	--	--	--	60.0%	49.4%	48.7%	49.9%	*48.5%*	*48.5%*	Common Equity Ratio	*46.5%*
	--	--	--	--	--	--	16716	17337	17924	18542	*19675*	*20175*	Total Capital ($mill)	*23400*
	--	--	--	--	--	--	18952	19346	20106	21150	*22100*	*23150*	Net Plant ($mill)	*26300*
	--	--	--	--	--	--	4.0%	4.8%	4.5%	5.7%	*5.0%*	*5.5%*	Return on Total Cap'l	*6.0%*
	--	--	--	--	--	--	5.3%	7.8%	7.1%	9.5%	*8.5%*	*9.0%*	Return on Shr. Equity	*10.0%*
	--	--	--	--	--	--	5.3%	7.8%	7.1%	9.5%	*8.5%*	*9.0%*	Return on Com Equity E	*10.0%*
	--	--	--	--	--	--	.6%	2.4%	1.8%	4.1%	*3.0%*	*3.0%*	Retained to Com Eq	*3.5%*
	--	--	--	--	--	--	89%	69%	75%	57%	*64%*	*65%*	All Div'ds to Net Prof	*63%*

BUSINESS: Evergy, Inc. was formed through the merger of Great Plains Energy and Westar Energy in June of 2018. Through its subsidiaries (now doing business under the Evergy name), provides electric service to 1.6 million customers in Kansas and Missouri, including the greater Kansas City area. Electric revenue breakdown: residential, 34%; commercial, 30%; industrial, 11%; wholesale, 13%; other, 12%. Generating sources: coal, 54%; nuclear, 17%; purchased, 29%. Fuel costs: 28% of revenues. '21 reported deprec. rate: 3%. Has 4,900 employees. Chairman: Mark A. Ruelle. President & CEO: David A. Campbell. COO: Kevin E. Bryant. Inc.: Missouri. Address: 1200 Main Street, Kansas City, Missouri 64105. Tel.: 816-556-2200. Internet: www.evergy.com.

Evergy delivered strong financial results in the third quarter. Earnings of $1.86 a share, on revenues of $1.9 billion, both exceeded Wall Street's expectations and increased 75%, and 27% from the last period, respectively. The performance was due primarily to the company's improved transmission margin, along with continued favorable demand in all sectors. Total demand has grown 3% this year and 2.4% in the September-period, driven by increases in industrial demand such as the chemical and oil and gas sectors.

The company raised its 2022 earnings range from $3.43-$3.63 a share to $3.53-$3.63 due to the better-than-expected September-period showing. Management remains committed to its long-term EPS growth-rate target of 6%-8% annualy. We have adjusted our top-line estimate which now stands at $5.7 billion, up from our previous call of $5.4 billion. In 2023, we are forecasting revenues of $5.8 billion and earnings of $3.75 per share.

Evergy has hiked its dividend by 7%. The dividend yield of 4.2%, which is solid for a utility should appeal to income-oriented investors. Management is targeting a dividend growth rate in line with earnings at a 60%-70% payout.

The company hopes to get approval on its acquisition of the Permisson Creek Wind Farm by year end. The $250 million investment will boost the renewable energy business and assist the utility in its goal of net-zero carbon emissions by 2045.

Evergy shares have underperformed of late. The stock has declined more than 16% in value over the past three months, alongside losses by many of its peers. The utility industry has struggled recently due to the challenging interest-rate environment. Higher yields on Treasuries have prompted a growing number of income-oriented investors to enter the bond market, and the competition has not augured well for utilities. Due to its recent price struggles, capital appreciation potential over the 18-month span, and 3- to 5-year period have improved since our last review. Also, these shares are ranked to mirror the broader market averages over the next year. But the dividend continues to be the main attraction here.

Zachary J. Hodgkinson December 9, 2022

(A) Diluted earnings. '19 EPS don't sum to full-year total due to rounding. Next earnings report due late February. **(B)** Dividends paid in mid-March, June, September, and December. ■ Dividend reinvestment plan available. **(C)** Incl. intangibles. In '21: $4,327.7 mill., $18.87/sh. **(D)** In millions. **(E)** Rate base: Original cost depreciated. Rate allowed on common equity in Missouri in '18: none specified; in Kansas in '18: 9.3%; earned on average common equity, '21: 9.8%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	85
Price Growth Persistence	35
Earnings Predictability	NMF

EVERSOURCE ENERGY NYSE-ES

RECENT PRICE **76.28** | P/E RATIO **18.1** (Trailing: 18.7 Median: 19.0) | RELATIVE P/E RATIO **1.18** | DIV'D YLD **3.5%** | **VALUE LINE**

TIMELINESS 3 Lowered 8/19/22
SAFETY 1 Raised 5/22/15
TECHNICAL 2 Lowered 11/4/22
BETA .90 (1.00 = Market)

18-Month Target Price Range

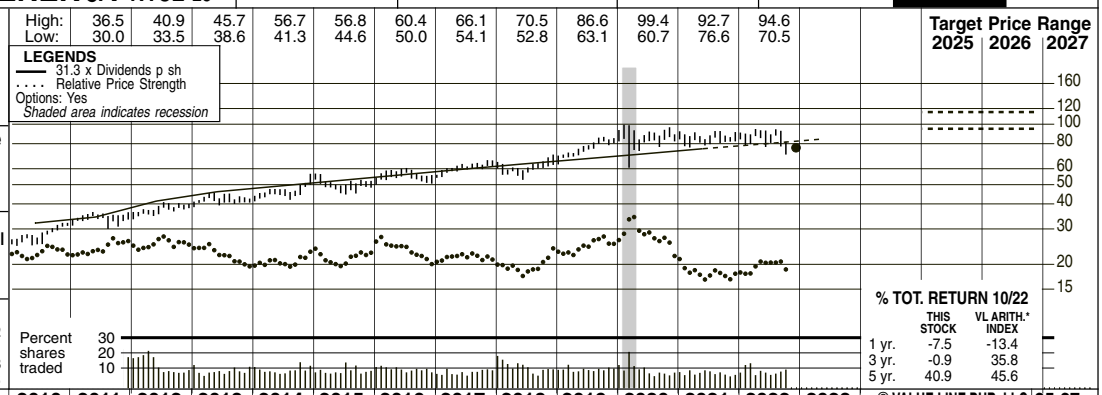
Low-High	Midpoint (% to Mid)
$78-$129	$104 (35%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	115	(+50%)	*14%*
Low	95	(+25%)	*9%*

Institutional Decisions

	4Q2021	1Q2022	2Q2022
to Buy	366	412	411
to Sell	312	315	308
Hld's(000)	275552	269412	271816



2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
44.64	37.27	37.22	30.97	27.76	25.21	19.98	23.16	24.42	25.08	24.11	24.46	26.66	25.85	25.96	28.64	***32.75***	***34.20***	Revenues per sh	***37.00***
3.69	4.82	6.16	4.96	5.68	4.88	4.03	5.22	4.56	4.94	5.46	5.84	6.64	6.65	6.99	7.74	***8.10***	***8.55***	"Cash Flow" per sh	***10.00***
.82	1.59	1.86	1.91	2.10	2.22	1.89	2.49	2.58	2.76	2.96	3.11	3.25	3.45	3.64	3.86	***4.10***	***4.40***	Earnings per sh [A]	***5.30***
.73	.78	.83	.95	1.03	1.10	1.32	1.47	1.57	1.67	1.78	1.90	2.02	2.14	2.27	2.41	***2.55***	***2.70***	Div'd Decl'd per sh [B] ■	***3.30***
5.49	7.14	8.06	5.17	5.41	6.08	4.69	4.62	5.06	5.44	6.24	7.41	7.96	8.83	8.58	9.22	***11.20***	***10.50***	Cap'l Spending per sh	***9.50***
18.14	18.65	19.38	20.37	21.60	22.65	29.41	30.49	31.47	32.64	33.80	34.99	36.25	38.29	41.01	42.39	***44.20***	***46.50***	Book Value per sh [C]	***53.75***
154.23	156.22	155.83	175.62	176.45	177.16	314.05	315.27	316.98	317.19	316.89	316.89	316.89	329.88	342.95	344.40	***348.00***	***351.00***	Common Shs Outst'g [D]	***365.00***
27.1	18.7	13.7	12.0	13.4	15.4	19.9	16.9	17.9	18.1	18.7	19.5	18.7	22.1	23.7	22.2	***Bold figures are Value Line estimates***		Avg Ann'l P/E Ratio	***19.5***
1.46	.99	.82	.80	.85	.97	1.27	.95	.94	.91	.98	.98	1.01	1.18	1.22	1.19			Relative P/E Ratio	***1.10***
3.3%	2.6%	3.2%	4.2%	3.6%	3.2%	3.5%	3.5%	3.4%	3.3%	3.2%	3.1%	3.3%	2.8%	2.6%	2.8%			Avg Ann'l Div'd Yield	***3.2%***
6273.8	7301.2	7741.9	7954.8	7639.1	7752.0	8448.2	8526.5	8904.4	9863.1	***11400***	***12000***	Revenues ($mill)	***13500***
533.0	793.7	827.7	886.0	949.8	995.5	1040.5	1121.0	1244.8	1337.7	***1430***	***1545***	Net Profit ($mill)	***1935***
34.0%	35.0%	36.2%	37.9%	36.9%	36.8%	21.7%	19.7%	22.2%	21.9%	***24.0%***	***24.0%***	Income Tax Rate	***24.0%***
2.3%	1.4%	2.4%	2.9%	3.9%	4.7%	6.1%	6.3%	5.3%	4.2%	***5.0%***	***4.0%***	AFUDC % to Net Profit	***3.0%***
43.7%	44.3%	45.9%	45.6%	44.8%	51.2%	52.4%	52.8%	52.4%	54.2%	***54.5%***	***55.0%***	Long-Term Debt Ratio	***56.0%***
55.4%	54.8%	53.2%	53.6%	54.4%	48.2%	46.9%	46.6%	47.1%	45.3%	***45.0%***	***44.5%***	Common Equity Ratio	***44.0%***
16675	17544	18738	19313	19697	23018	24474	27097	29842	32233	***34325***	***36650***	Total Capital ($mill)	***44700***
16605	17576	18647	19892	21351	23617	25610	27585	30883	33378	***36025***	***38400***	Net Plant ($mill)	***44500***
4.2%	5.5%	5.3%	5.5%	5.8%	5.2%	5.2%	5.1%	5.1%	5.1%	***5.0%***	***5.0%***	Return on Total Cap'l	***5.5%***
5.7%	8.1%	8.2%	8.4%	8.7%	8.9%	8.9%	8.8%	8.8%	9.1%	***9.0%***	***9.5%***	Return on Shr. Equity	***10.0%***
5.7%	8.2%	8.2%	8.5%	8.8%	8.9%	9.0%	8.8%	8.8%	9.1%	***9.0%***	***9.5%***	Return on Com Equity [E]	***10.0%***
1.6%	3.4%	3.5%	3.4%	3.5%	3.5%	3.4%	3.6%	3.5%	3.6%	***3.5%***	***3.5%***	Retained to Com Eq	***3.5%***
72%	59%	58%	61%	60%	61%	62%	60%	60%	61%	***62%***	***62%***	All Div'ds to Net Prof	***62%***

CAPITAL STRUCTURE as of 6/30/22
Total Debt $21423 mill. **Due in 5 Yrs** $8313.5 mill.
LT Debt $20016 mill. **LT Interest** $619.8 mill.
(Total Interest coverage: 3.9x)

Leases, Uncapitalized Annual rentals $11.1 mill.

Pension Assets-12/21 $6495.5 mill.
Oblig $6729.7 mill.
Pfd Stock $155.6 mill. **Pfd Div'd** $7.6 mill.

Common Stock 346,443,316 shs.
as of 7/31/22
MARKET CAP: $26.4 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-3.3	-2.7	+1.6
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	NA	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.7	+.8	+.6
Fixed Charge Cov. (%)	319	345	324

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-.5%	2.0%	*5.5%*
"Cash Flow"	3.5%	7.5%	*6.0%*
Earnings	6.0%	5.5%	*6.5%*
Dividends	8.5%	6.5%	*6.5%*
Book Value	6.5%	4.5%	*5.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	2416	1884	2176	2050	8526.5
2020	2373	1953	2344	2234	8904.4
2021	2826	2122	2433	2482	9863.1
2022	3471	2573	***2750***	***2606***	***11400***
2023	***3650***	***2700***	***2900***	***2750***	***12000***

Calendar	EARNINGS PER SHARE [A] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.97	.74	.98	.76	3.45
2020	1.02	.76	1.01	.85	3.64
2021	1.15	.79	1.02	.91	3.86
2022	1.30	.86	***1.03***	***.91***	***4.10***
2023	***1.35***	***.92***	***1.11***	***1.02***	***4.40***

Calendar	QUARTERLY DIVIDENDS PAID [B] ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.505	.505	.505	.505	2.02
2019	.535	.535	.535	.535	2.14
2020	.5675	.5675	.5675	.5675	2.27
2021	.6025	.6025	.6025	.6025	2.41
2022	.6375	.6375	.6375		

BUSINESS: Eversource Energy (formerly Northeast Utilities) is the parent of utilities with 3.3 mill. electric, 887,000 gas, 226,000 water customers. Supplies power to most of Connecticut and gas to part of Connecticut; supplies power to 3/4 of New Hampshire's population; supplies power to western Massachusetts and parts of eastern MA & gas to central & eastern MA; supplies water to CT, MA, & NH. Acq'd NSTAR 4/12; Aquarion 12/17; Columbia Gas 10/20. Electric rev. breakdown: residential, 53%; commercial, 33%; industrial, 5%; other, 9%. Fuel costs: 34% of revs. '21 reported depr. rate: 3.1%. Has 9,200 empls. Chairman: James J. Judge. Pres. & CEO: Joseph R. Nolan, Jr. Inc.: MA. Address: 300 Cadwell Drive, Springfield, MA 01104. Tel.: 413-785-5871. Internet: www.eversource.com.

Eversource Energy is on pace for a solid year. The company is receiving a full year's effect from last November's natural gas price hike in Massachusetts, with the rate set to rise again this November. Eversource is also benefiting from transmission and distribution (T&D) capital projects, which raise the rate base (property, plant, and equipment on which utilities are allowed to earn an economic rate of return). The rising rate base increases the company's electric rates annually through a forward-looking algorithm that takes regulatory lag out of the equation for T&D investments. We expect earnings will be up about 6.5% this year to $4.10 per share. (Note: Eversource is due to report third-quarter financial results shortly after this report goes to press.)

We look for more of the same going forward. NSTAR has a pending electric rate case in Massachusetts, with a decision due in December. The utility requested increases of $46 million and $47 million at the start of 2023 and 2024, respectively, based on a 10.5% return on equity (50 basis points higher than the rate of return granted in 2018). This may be a bit of a stretch. Nevertheless, we think a constructive outcome is likely and rates should increase in January.

Leadership has adjusted its clean-energy strategy. Eversource is shopping its stake in non-regulated offshore wind ventures, deeming them outside of its risk tolerance and too high a drain on capital. Instead, the company plans to benefit from this new power source's growth in New England through the relative safety of regulated T&D projects, such as those necessary to connect wind generation to the grid. Modernization programs that ready its territories for the electrification of the transportation system will also serve to grow its rate base. Regulated renewable-power-generation ventures will likely remain a viable option, as well.

Total returns for this issue over the 18-month time frame look attractive. We view Eversource as a desirable holding for utility investors due to its superior earnings and dividend growth rates relative to its peer group. Its yield is 30 basis points below the industry average, but we think the valuation premium is justified.

Anthony J. Glennon *November 11, 2022*

(A) Diluted EPS. Excl. nonrecurring gain (losses): '08, (19¢); '10, 9¢; '19, (64¢); '20, (9¢); '21, (32¢); 1Q-2Q '22, (3¢). Next earnings report due early Feb. **(B)** Div'ds historically paid late Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. **(C)** Incl. deferred charges. In '21: $9064 mill., $26.32/sh. **(D)** In mill. **(E)** Rate allowed on com. eq. in MA: (elec.) '18, 10.0%; (gas) '20, 9.7%-9.9%; in CT: (elec.) '18, 9.25%; (gas) '18, 9.3%; in NH: '21, 9.3%; Regulatory Climate: CT, Below Average; NH, Average; MA, Above Average.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	65
Earnings Predictability	100

IDACORP, INC. NYSE-IDA

RECENT PRICE **96.53** | P/E RATIO **19.2** (Trailing: 20.3 Median: 19.0) | RELATIVE P/E RATIO **1.31** | DIV'D YLD **3.1%** | **VALUE LINE**

TIMELINESS 4 Lowered 9/23/22
SAFETY 1 Raised 1/22/21
TECHNICAL 2 Raised 10/14/22
BETA .80 (1.00 = Market)

18-Month Target Price Range

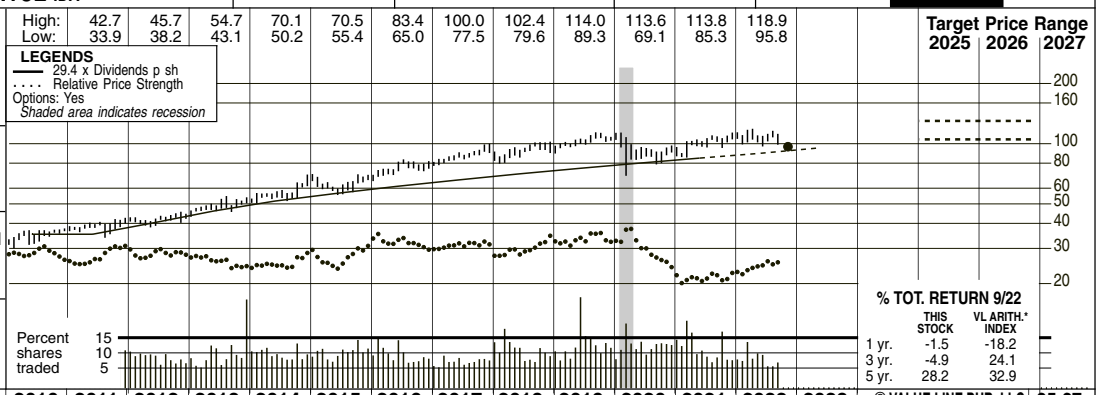
Low-High	Midpoint (% to Mid)
$94-$148	$121 (25%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	130	(+35%)	*10%*
Low	105	(+10%)	*5%*

Institutional Decisions

	4Q2021	1Q2022	2Q2022
to Buy	208	181	174
to Sell	137	164	164
Hld's(000)	39410	39894	40518



2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
21.23	19.51	20.47	21.92	20.97	20.55	21.55	24.81	25.51	25.23	25.04	26.76	27.19	26.70	26.77	28.86	*28.40*	*28.65*	Revenues per sh	*34.25*
4.58	4.11	4.27	5.07	5.35	5.84	5.93	6.29	6.58	6.70	6.86	7.50	7.85	8.07	8.19	8.41	*8.30*	*8.85*	"Cash Flow" per sh	*10.40*
2.35	1.86	2.18	2.64	2.95	3.36	3.37	3.64	3.85	3.87	3.94	4.21	4.49	4.61	4.69	4.85	*5.00*	*5.25*	Earnings per sh A	*6.00*
1.20	1.20	1.20	1.20	1.20	1.20	1.37	1.57	1.76	1.92	2.08	2.24	2.40	2.56	2.72	2.88	*3.05*	*3.25*	Div'd Decl'd per sh B ■ †	*4.00*
5.16	6.39	5.19	5.26	6.85	6.76	4.78	4.68	5.45	5.84	5.89	5.66	5.51	5.53	6.16	5.94	*10.15*	*14.20*	Cap'l Spending per sh	*10.10*
25.77	26.79	27.76	29.17	31.01	33.19	35.07	36.84	38.85	40.88	42.74	44.65	47.01	48.88	50.73	52.82	*54.65*	*56.45*	Book Value per sh C	*63.95*
43.63	45.06	46.92	47.90	49.41	49.95	50.16	50.23	50.27	50.34	50.40	50.42	50.42	50.42	50.46	50.52	*50.70*	*51.00*	Common Shs Outst'g D	*52.00*
15.1	18.2	13.9	10.2	11.8	11.5	12.4	13.4	14.7	16.2	19.1	20.6	20.5	22.3	19.9	20.8	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*19.5*
.82	.97	.84	.68	.75	.72	.79	.75	.77	.82	1.00	1.04	1.11	1.19	1.02	1.14			Relative P/E Ratio	*1.10*
3.4%	3.5%	4.0%	4.5%	3.4%	3.1%	3.3%	3.2%	3.1%	3.1%	2.8%	2.6%	2.6%	2.5%	2.9%	2.9%			Avg Ann'l Div'd Yield	*3.4%*
1080.7	1246.2	1282.5	1270.3	1262.0	1349.5	1370.8	1346.4	1350.7	1458.1	*1440*	*1460*	Revenues ($mill)	*1780*
168.9	182.4	193.5	194.7	198.3	212.4	226.8	232.9	237.4	245.6	*255*	*270*	Net Profit ($mill)	*310*
13.4%	28.3%	8.0%	19.0%	15.5%	18.6%	7.1%	9.5%	10.8%	13.1%	*13.0%*	*13.0%*	Income Tax Rate	*13.0%*
20.3%	12.3%	13.6%	16.3%	16.3%	13.9%	15.2%	16.2%	17.3%	17.7%	*20.0%*	*21.0%*	AFUDC % to Net Profit	*16.0%*
45.5%	46.6%	45.3%	45.6%	44.8%	43.7%	43.6%	41.3%	43.9%	42.8%	*43.5%*	*47.5%*	Long-Term Debt Ratio	*50.0%*
54.5%	53.4%	54.7%	54.4%	55.2%	56.3%	56.4%	58.7%	56.1%	57.2%	*56.5%*	*52.5%*	Common Equity Ratio	*50.0%*
3225.4	3465.9	3567.6	3783.3	3898.5	3997.5	4205.1	4201.3	4560.4	4669.1	*4920*	*5505*	Total Capital ($mill)	*6675*
3536.0	3665.0	3833.5	3992.4	4172.0	4283.9	4395.7	4531.5	4709.5	4901.8	*5300*	*5800*	Net Plant ($mill)	*6730*
6.5%	6.4%	6.6%	6.2%	6.1%	6.3%	6.4%	6.5%	6.1%	6.2%	*6.0%*	*5.5%*	Return on Total Cap'l	*5.5%*
9.6%	9.9%	9.9%	9.5%	9.2%	9.4%	9.6%	9.4%	9.3%	9.2%	*9.0%*	*9.0%*	Return on Shr. Equity	*9.0%*
9.6%	9.9%	9.9%	9.5%	9.2%	9.4%	9.6%	9.4%	9.3%	9.2%	*9.0%*	*9.0%*	Return on Com Equity E	*9.0%*
5.7%	5.6%	5.4%	4.8%	4.3%	4.4%	4.4%	4.2%	3.9%	3.7%	*3.5%*	*3.5%*	Retained to Com Eq	*3.0%*
41%	43%	46%	50%	53%	53%	54%	56%	58%	60%	*61%*	*62%*	All Div'ds to Net Prof	*67%*

CAPITAL STRUCTURE as of 6/30/22
Total Debt $2150.7 mill. **Due in 5 Yrs** $325.0 mill.
LT Debt $2075.7 mill. **LT Interest** $100.0 mill.
(LT interest earned: 3.8x)

Pension Assets-12/21 $984.5 mill.
Oblig $1346.5 mill.

Pfd Stock None

Common Stock 50,560,040 shs.
as of 7/29/22

MARKET CAP: $4.9 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-.3	+2.0	+3.9
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	5.32	5.38	5.62
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	3242	3392	3751
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+2.5	+2.7	+2.8
Fixed Charge Cov. (%)	307	313	334

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	2.5%	1.5%	*4.0%*
"Cash Flow"	4.5%	4.0%	*4.0%*
Earnings	4.5%	4.0%	*4.0%*
Dividends	8.5%	7.0%	*6.5%*
Book Value	5.0%	4.5%	*4.0%*

QUARTERLY REVENUES($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	350.3	316.9	386.3	292.9	1346.4
2020	291.0	318.8	425.3	315.6	1350.7
2021	316.1	360.1	446.9	335.0	1458.1
2022	344.3	358.7	*425*	*312.0*	*1440*
2023	*350*	*360*	*430*	*320*	*1460*

EARNINGS PER SHARE A

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.84	1.05	1.78	.93	4.61
2020	.74	1.19	2.02	.74	4.69
2021	.89	1.38	1.93	.65	4.85
2022	.91	1.27	*2.00*	*.82*	*5.00*
2023	*.95*	*1.40*	*2.05*	*.85*	*5.25*

QUARTERLY DIVIDENDS PAID B ■ †

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.59	.59	.59	.63	2.40
2019	.63	.63	.63	.67	2.56
2020	.67	.67	.67	.71	2.72
2021	.71	.71	.71	.75	2.88
2022	.75	.75	.75		

BUSINESS: IDACORP, Inc. is a holding company for Idaho Power Company, a regulated electric utility that serves 604,000 customers throughout a 24,000-square-mile area in southern Idaho and eastern Oregon (population: 1.3 million). Most of the company's revenues are derived from the Idaho portion of its service area. Revenue breakdown: residential, 45%; commercial, 24%; industrial, 15%; irrigation, 13%; other, 3%. Generating sources: hydro, 30%; coal, 17%; gas, 15%; purchased, 38%. Fuel costs: 36% of revenues. '21 reported depreciation rate: 2.9%. Has 2,000 employees. Chairman: Richard J. Dahl. President & CEO: Lisa Grow. Incorporated: Idaho. Address: 1221 W. Idaho St., Boise, Idaho 83702. Telephone: 208-388-2200. Internet: www.idacorpinc.com.

Annual earnings growth at IDACORP is pegged to be 3% and 5%, respectively, in 2022 and 2023. Weather-related usage and transmission wheeling revenues are trending higher, aided by solid population growth in the areas that IDA serves. Air conditioning and irrigation have been primary drivers and should be for the foreseeable future. Too, the likelihood of a rate increase is certainly on the table (more color below) for next year, though nothing is set in stone on that front. With that, we think share net can climb to $5.00 this year, followed by an expected 5% annual increase to $5.25 in 2023.

One would need to go back to 2011 for the most recent rate case in Idaho Power's jurisdiction. That is more than a decade of no rate applications, a period marked by a lofty influx of people into IDA's areas of operation. Management has capital budget plans that will require funding, notably the increased stake it is taking in a transmission line and the financing of larger battery storage capabilities. Dipping in to debt markets will probably be the first move, even as rates are heading north, with an issuance of equity on the slate for 2024.

Capital expenditures are primed for an uptick next year, but should recede after that. For 2022, we look for the cap ex number to come in around $515 million. However, in 2023, we have that amount climbing to $725 million, with the vast majority earmarked for new capacity resources. A recent integrated resources plan came back stating that IDA could have a 125 MW capacity deficit by 2025. This is where using the battery storage comes into the situation. Too, the company's exit from coal-fired manufacturing will require adding significant generation capabilities. A new transmission line will help, but it will not come cheap.

IDACORP's shares are of high quality, but we are not recommending them at this time. For starters, the issue's yield is noticeably below what we deem as average for the utility stocks in our coverage universe. Add to this, the equity has dipped one notch to Below Average (4) on our Timeliness Ranking Scale. Lastly, total return potential three to five years hence does little to quicken the pulse.

Erik M. Manning *October 21, 2022*

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	75
Earnings Predictability	100

(A) Diluted EPS. Excl. nonrecurring gain: '06, 17¢. '19 earnings don't sum due to rounding. Next earnings report due last week of October. **(B)** Dividends historically paid in late Feb., May, Aug., and Nov. ■ Dividend reinvestment plan available. † Shareholder investment plan available. **(C)** Incl. intangibles. In '21: $1,462.4 mill., $28.95/sh. **(D)** In millions. **(E)** Rate base: Net original cost. Rate allowed on common equity in '12: 10% (imputed); earned on avg. com. eq., '21: 9.4%. Regulatory Climate: Above Average.

NORTHWESTERN NDQ-NWE

RECENT PRICE **49.48** | P/E RATIO **14.5** (Trailing: 14.9 Median: 17.0) | RELATIVE P/E RATIO **0.99** | DIV'D YLD **5.2%** | **VALUE LINE**

TIMELINESS 5 Lowered 9/9/22
SAFETY 2 Raised 7/27/18
TECHNICAL 3 Raised 10/21/22
BETA .90 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$46-$69	$58 (15%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+50%)	*15%*
Low	55	(+10%)	*8%*

Institutional Decisions

	4Q2021	1Q2022	2Q2022
to Buy	170	154	140
to Sell	105	111	121
Hld's(000)	56973	57800	56756

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
High:	36.6	38.0	47.2	58.7	59.7	63.8	64.5	65.7	76.7	80.5	70.8	63.1								
Low:	27.4	33.0	35.1	42.6	48.4	52.2	55.7	50.0	57.3	45.1	53.2	49.1								
	31.49	30.79	35.09	31.72	30.66	30.80	28.76	29.80	25.68	25.21	26.01	26.45	23.81	24.93	23.70	25.38	*24.15*	*23.55*	Revenues per sh	*25.75*
	3.62	3.70	4.40	4.62	4.76	5.42	5.18	5.45	5.39	5.92	6.74	6.76	6.96	7.07	6.86	6.92	*6.70*	*6.85*	"Cash Flow" per sh	*8.00*
	1.31	1.44	1.77	2.02	2.14	2.53	2.26	2.46	2.99	2.90	3.39	3.34	3.40	3.53	3.21	3.50	*3.35*	*3.55*	Earnings per sh [A]	*4.00*
	1.24	1.28	1.32	1.34	1.36	1.44	1.48	1.52	1.60	1.92	2.00	2.10	2.20	2.30	2.40	2.48	*2.52*	*2.56*	Div'd Decl'd per sh [B] ■ †	*2.68*
	2.81	3.00	3.47	5.26	6.30	5.20	5.89	5.95	5.76	5.89	5.96	5.60	5.64	6.26	8.02	8.03	*10.05*	*9.10*	Cap'l Spending per sh	*6.50*
	20.65	21.12	21.25	21.86	22.64	23.68	25.09	26.60	31.50	33.22	34.68	36.44	38.60	40.42	41.10	43.28	*44.60*	*46.30*	Book Value per sh [C]	*50.00*
	35.97	38.97	35.93	36.00	36.23	36.28	37.22	38.75	46.91	48.17	48.33	49.37	50.32	50.45	50.59	54.06	*58.00*	*62.00*	Common Shs Outst'g [D]	*62.00*
	26.0	21.7	13.9	11.5	12.9	12.6	15.7	16.9	16.2	18.4	17.2	17.8	16.8	19.9	18.6	17.4	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*16.5*
	1.40	1.15	.84	.77	.82	.79	1.00	.95	.85	.93	.90	.90	.91	1.06	.96	.94			Relative P/E Ratio	*.90*
	3.6%	4.1%	5.4%	5.7%	4.9%	4.5%	4.2%	3.7%	3.3%	3.6%	3.4%	3.5%	3.9%	3.3%	4.0%	4.1%			Avg Ann'l Div'd Yield	*4.1%*
							1070.3	1154.5	1204.9	1214.3	1257.2	1305.7	1198.1	1257.9	1198.7	1372.3	*1400*	*1460*	Revenues ($mill)	*1600*
							83.7	94.0	120.7	138.4	164.2	162.7	171.1	179.3	162.6	181.6	*190*	*215*	Net Profit ($mill)	*250*
							9.6%	13.2%	- -	13.7%	- -	7.6%	- -	1.6%	1.6%	.9%	*1.5%*	*3.0%*	Income Tax Rate	*12.0%*
							9.4%	8.7%	8.9%	9.8%	4.3%	5.2%	3.4%	4.6%	6.0%	14.9%	*16.0%*	*14.0%*	AFUDC % to Net Profit	*10.0%*
							53.8%	53.5%	53.4%	53.1%	52.0%	50.2%	52.2%	52.5%	52.8%	52.2%	*50.0%*	*49.5%*	Long-Term Debt Ratio	*49.0%*
							46.2%	46.5%	46.6%	46.9%	48.0%	49.8%	47.8%	47.5%	47.2%	47.8%	*50.0%*	*50.5%*	Common Equity Ratio	*51.0%*
							2020.7	2215.7	3168.0	3408.6	3493.9	3614.5	4064.6	4289.8	4409.1	4893.1	*5195*	*5675*	Total Capital ($mill)	*6050*
							2435.6	2690.1	3758.0	4059.5	4214.9	4358.3	4521.3	4700.9	4952.9	5247.2	*5630*	*5980*	Net Plant ($mill)	*6550*
							5.5%	5.5%	4.8%	5.2%	5.9%	5.6%	5.2%	5.2%	4.6%	4.6%	*4.5%*	*4.5%*	Return on Total Cap'l	*5.0%*
							9.0%	9.1%	8.2%	8.6%	9.8%	9.0%	8.8%	8.8%	7.8%	7.8%	*7.5%*	*7.5%*	Return on Shr. Equity	*8.0%*
							9.0%	9.1%	8.2%	8.6%	9.8%	9.0%	8.8%	8.8%	7.8%	7.8%	*7.5%*	*7.5%*	Return on Com Equity [E]	*8.0%*
							3.2%	3.5%	3.8%	3.0%	4.1%	3.4%	3.2%	3.1%	2.0%	2.3%	*2.0%*	*2.0%*	Retained to Com Eq	*2.5%*
							65%	61%	54%	65%	58%	62%	64%	64%	74%	71%	*75%*	*72%*	All Div'ds to Net Prof	*67%*

CAPITAL STRUCTURE as of 6/30/22
Total Debt $2533.4 mill. **Due in 5 Yrs** $1037.4 mill.
LT Debt $2530.4 mill. **LT Interest** $87.8 mill.
Incl. $11.9 mill. finance leases.
(Total Interest Coverage: 2.7x)

Pension Assets-12/21 $605.5 mill.
Oblig $696.8 mill.

Pfd Stock None

Common Stock 56,150,050 shs.
as of 7/22/22

MARKET CAP: $2.8 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	+4.6	-4.4	+.7
Avg. Indust. Use (MWH)	37808	33526	31792
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Winter (Mw)	2237	NA	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.2	+1.2	+1.6
Fixed Charge Cov. (%)	284	237	252

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-2.5%	-1.0%	*.5%*
"Cash Flow"	3.5%	3.0%	*2.5%*
Earnings	4.5%	2.0%	*2.5%*
Dividends	5.5%	5.5%	*2.0%*
Book Value	6.0%	4.5%	*3.0%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	384.2	270.7	274.8	328.2	1257.9
2020	335.3	269.4	280.6	313.4	1198.7
2021	400.8	298.2	326.0	347.3	1372.3
2022	394.5	323.0	*330.5*	*352*	*1400*
2023	*415*	*330*	*345*	*370*	*1460*

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	1.44	.49	.42	1.18	3.53
2020	1.00	.43	.58	1.21	3.21
2021	1.24	.59	.70	.97	3.50
2022	1.08	.58	*.64*	*1.05*	*3.35*
2023	*1.15*	*.60*	*.70*	*1.10*	*3.55*

QUARTERLY DIVIDENDS PAID [B] ■ †

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.55	.55	.55	.55	2.20
2019	.575	.575	.575	.575	2.30
2020	.60	.60	.60	.60	2.40
2021	.62	.62	.62	.62	2.48
2022	.63	.63	.63		

BUSINESS: NorthWestern Corporation (doing business as NorthWestern Energy) supplies electricity & gas in the Upper Midwest and Northwest, serving 456,000 electric customers in Montana and South Dakota and 298,000 gas customers in Montana (85% of gross margin), South Dakota (14%), and Nebraska (1%). Electric revenue breakdown: residential, 43%; commercial, 49%; industrial, 4%; other, 4%. Generating sources: coal, 28%; hydro, 27%; wind, 6%; other, 4%; purchased, 35%. Fuel costs: 31% of revenues. '21 reported deprec. rate: 2.8%. Has 1,500 employees. Chairman: Dana J. Dykhouse. CEO: Robert C. Rowe. President & COO: Brian B. Bird. Inc.: DE. Address: 3010 West 69th Street, Sioux Falls, SD 57108. Tel.: 605-978-2900. Internet: www.northwesternenergy.com.

NorthWestern shares have flatlined for years, commensurate with EPS. Since 2015, this issue has mainly traded within the $50-$60 price range, breaking out briefly from time to time. While net profits have grown gradually over the past several years (the 2016-2022 average annual rate is 2%), shares outstanding have also risen, diluting per-share gains. The main constraint, besides dilution, has been years of underearning the utility's allowable ROE. This is largely due to the relative constraints of the rate-relief mechanisms available in the company's utility territories, which results in regulatory lag. In other words, the company foots the bill for grid maintenance and upgrades but has to justify it and wait for the payback.

Management has a solid plan in place that should help reignite growth. In an effort to become less reliant on purchased power, while modernizing and shoring up reliability, the company is looking to add significant gas-fired capacity in both South Dakota and Montana. An $83 million, 58-megawatt plant in South Dakota was completed in the second quarter. And in April, NWE broke ground on a $275 million, 175-mw facility in Montana, expected to be operational by late 2023. Financing is via a $200 million equity offering ($53.50 a share) completed in fourth quarter 2021, with $300 million more expected in early 2023 via a forward sale.

Results depend on an upcoming general rate case decision. NWE has filed its case, and likely will obtain rate relief early next year. The company is also asking for pricing mechanisms that would help alleviate regulatory lag. This may be a tough sell in a historically difficult regulatory environment. Assuming the capacity expansion is allowed to proceed, it would lift the rate base and help to narrow the gap between NWE's earned and allowable ROE. Our projections assume an annual growth rate in share net from 2023 to mid-decade of 4%. It's somewhat below the industry average, yet significantly better than what's transpired in recent years.

This issue is untimely. However, at the recent valuation there may be some appeal for utility investors seeking outsized income. The yield is 115 basis points above the electric utility industry median.

Anthony J. Glennon *October 21, 2022*

(A) Diluted EPS. Excl. nonrec. gains/(losses): '12, 40¢; '15, 27¢; '18, 52¢; '19, 45¢; '20, (15¢); '21, 10¢; Q1-Q2 '22, (4¢). '20 EPS don't sum due to rounding. Next egs. report due late Oct. **(B)** Div'ds historically paid in late Mar., June, Sept. & Dec. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. **(C)** Incl. def'd charges. In '21: $19.39/sh. **(D)** In mill. **(E)** Rate base: Net orig. cost. Rate allowed on com. eq. in MT in '19 (elec.): 9.65%; in '17 (gas): 9.55%; in SD in '15: none specified; in NE in '07: 10.4%. Regulatory Climate: Below Average.

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	40
Earnings Predictability	90

OGE ENERGY CORP. NYSE-OGE

RECENT PRICE **39.75** | P/E RATIO **18.0** (Trailing: 17.5 Median: 17.0) | RELATIVE P/E RATIO **1.10** | DIV'D YLD **4.2%** | **VALUE LINE**

TIMELINESS 3 Raised 5/20/22
SAFETY 2 Lowered 12/18/15
TECHNICAL 3 Lowered 12/9/22
BETA 1.00 (1.00 = Market)

18-Month Target Price Range

Low-High	Midpoint (% to Mid)
$33-$51	$42 (5%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+40%)	*12%*
Low	40	(Nil)	*4%*

Institutional Decisions

	1Q2022	2Q2022	3Q2022
to Buy	228	218	185
to Sell	170	182	192
Hld's(000)	129869	136256	136256

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
High:	28.6	30.1	40.0	39.3	36.5	34.2	37.4	41.8	45.8	46.4	38.6	42.9						
Low:	20.3	25.1	27.7	32.8	24.2	23.4	32.6	29.6	38.0	23.0	29.2	33.3						

Target Price Range 2025 2026 2027

LEGENDS
25.00 x Dividends p sh divided by Interest Rate
Relative Price Strength
2-for-1 split 7/13
Options: Yes
Shaded area indicates recession

Percent shares traded 18 12 6

% TOT. RETURN 10/22

	THIS STOCK	VL ARITH.* INDEX
1 yr.	12.3	-13.4
3 yr.	-3.1	35.8
5 yr.	22.1	45.6

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21.96	20.68	21.77	14.79	19.04	19.96	18.58	14.45	12.30	11.00	11.31	11.32	11.37	11.15	10.61	18.26	***16.00***	***16.50***	Revenues per sh	***18.25***
2.23	2.39	2.40	2.69	3.01	3.31	3.69	3.46	3.40	3.23	3.31	3.34	3.74	4.02	4.03	4.44	***4.45***	***4.40***	"Cash Flow" per sh	***6.25***
1.23	1.32	1.25	1.33	1.50	1.73	1.79	1.94	1.98	1.69	1.69	1.92	2.12	2.24	2.08	2.36	***2.25***	***2.10***	Earnings per sh [A]	***3.25***
.67	.68	.70	.71	.73	.76	.80	.85	.95	1.05	1.16	1.27	1.40	1.51	1.58	1.63	***1.64***	***1.70***	Div'd Decl'd per sh [B] ■	***1.85***
2.67	3.04	4.01	4.37	4.36	6.48	5.85	4.99	2.86	2.74	3.31	4.13	2.87	3.18	3.25	3.89	***4.75***	***4.75***	Cap'l Spending per sh	***4.75***
8.79	9.16	10.14	10.52	11.73	13.06	14.00	15.30	16.27	16.66	17.24	19.28	20.06	20.69	18.15	20.27	***21.25***	***22.25***	Book Value per sh [C]	***26.00***
182.40	183.60	187.00	194.00	195.20	196.20	197.60	198.50	199.40	199.70	199.70	199.70	199.70	200.10	200.10	200.10	***200.20***	***200.20***	Common Shs Outst'g [D]	***200.20***
13.7	13.8	12.4	10.8	13.3	14.4	15.2	17.7	18.3	17.7	17.7	18.3	16.5	19.0	16.2	14.3			Avg Ann'l P/E Ratio	***14.0***
.74	.73	.75	.72	.85	.90	.97	.99	.96	.89	.93	.92	.89	1.01	.83	.76			Relative P/E Ratio	***.80***
4.0%	3.8%	4.5%	5.0%	3.7%	3.1%	2.9%	2.5%	2.6%	3.5%	3.9%	3.6%	4.0%	3.5%	4.7%	4.8%			Avg Ann'l Div'd Yield	***4.0%***

Bold figures are Value Line estimates

3671.2	2867.7	2453.1	2196.9	2259.2	2261.1	2270.3	2231.6	2122.3	3653.7	***3200***	***3300***	Revenues ($mill)	***3650***
355.0	387.6	395.8	337.6	338.2	384.3	425.5	449.6	415.9	472.5	***450***	***420***	Net Profit ($mill)	***665***
26.0%	24.9%	30.4%	29.2%	30.5%	32.5%	14.5%	7.4%	13.2%	11.5%	***12.0%***	***12.0%***	Income Tax Rate	***12.0%***
2.7%	2.6%	1.7%	3.7%	6.4%	15.0%	8.3%	1.6%	1.6%	2.2%	***2.0%***	***2.0%***	AFUDC % to Net Profit	***2.0%***
50.7%	43.1%	45.9%	44.3%	41.1%	41.7%	42.0%	43.6%	49.0%	52.6%	***46.0%***	***52.0%***	Long-Term Debt Ratio	***50.0%***
49.3%	56.9%	54.1%	55.7%	58.9%	58.3%	58.0%	56.4%	51.0%	47.4%	***53.0%***	***48.0%***	Common Equity Ratio	***50.0%***
5615.8	5337.2	5999.7	5971.6	5849.6	6600.7	6902.0	7334.7	7126.2	8552.7	***8100***	***9400***	Total Capital ($mill)	***10400***
8344.8	6672.8	6979.9	7322.4	7696.2	8339.9	8643.8	9044.6	9374.6	9832.9	***10345***	***10830***	Net Plant ($mill)	***12075***
7.7%	8.6%	7.8%	6.9%	7.0%	7.0%	7.3%	7.1%	6.9%	6.4%	***7.5%***	***6.5%***	Return on Total Cap'l	***7.5%***
12.8%	12.8%	12.2%	10.2%	9.8%	10.0%	10.6%	10.9%	11.5%	11.6%	***12.0%***	***12.0%***	Return on Shr. Equity	***13.0%***
12.8%	12.8%	12.2%	10.2%	9.8%	10.0%	10.6%	10.9%	11.5%	11.6%	***12.0%***	***12.0%***	Return on Com Equity [E]	***13.0%***
7.2%	7.3%	6.5%	4.0%	3.3%	3.5%	3.8%	3.6%	2.8%	3.6%	***4.0%***	***4.5%***	Retained to Com Eq	***5.5%***
44%	43%	47%	61%	67%	64%	64%	67%	76%	69%	***73%***	***81%***	All Div'ds to Net Prof	***57%***

CAPITAL STRUCTURE as of 9/30/22
Total Debt $5279.5 mill. **Due in 5 Yrs** $1731.5 mill.
LT Debt $3548.0 mill. **LT Interest** $158.7 mill.
(LT interest earned: 4.3x)

Leases, Uncapitalized Annual rentals $5.7 mill.

Pension Assets-12/21 $486.0 mill.
Oblig $502.9 mill.

Pfd Stock None

Common Stock 200,202,672 shs.

MARKET CAP: $8.0 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	+1.1	-4.9	+2.6
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	4.69	4.40	7.68
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	6817	6437	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.0	+1.1	+1.4
Fixed Charge Cov. (%)	335	326	336

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	-3.0%	3.0%	*5.5%*
"Cash Flow"	3.5%	4.5%	*7.0%*
Earnings	4.0%	4.5%	*6.5%*
Dividends	8.0%	8.5%	*3.0%*
Book Value	5.5%	3.5%	*5.5%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	490.0	513.7	755.4	472.5	2231.6
2020	431.3	503.5	702.1	485.4	2122.3
2021	1630.6	577.4	864.4	581.3	3653.7
2022	589.3	803.7	1270.8	***536.2***	***3200***
2023	***600***	***800***	***1200***	***700***	***3300***

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.24	.50	1.25	.26	2.24
2020	.23	.51	1.04	.30	2.08
2021	.26	.56	1.26	.27	2.36
2022	.33	.36	1.31	***.25***	***2.25***
2023	***.32***	***.33***	***1.25***	***.20***	***2.10***

QUARTERLY DIVIDENDS PAID [B] ■

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.3325	.3325	.3325	.365	1.36
2019	.365	.365	.365	.388	1.48
2020	.3875	.3875	.3875	.4025	1.57
2021	.4025	.4025	.4025	.41	1.62
2022	.41	.41	.41	.4141	

BUSINESS: OGE Energy Corp. is a holding company for Oklahoma Gas and Electric Company (OG&E), which supplies electricity to 879,000 customers in Oklahoma (84% of electric revenues) and western Arkansas (8%); wholesale is (8%). Owns 3% of Energy Transfer's limited partnership units. Electric revenue breakdown: residential, 44%; commercial, 25%; industrial, 11%; oilfield, 10%; other, 10%. Generating sources: gas, 25%; coal, 21%; wind, 6%; purchased, 48%. Fuel costs: 58% of revenues. '21 reported depreciation rate (utility): 2.6%. Has 2,200 employees. Chairman, President and Chief Executive Officer: Sean Trauschke. Incorporated: Oklahoma. Address: 321 North Harvey, P.O. Box 321, Oklahoma City, OK 73101-0321. Tel.: 405-553-3000. Internet: www.oge.com.

OGE Energy's utility subsidiary in Oklahoma agreed to a $30 million settlement in its general rate case. The company initially requested a $164 million increase which was reduced drastically by the Oklahoma Corporation Commission after regulatory hearings. The commission is now considering spreading out monthly price increases of $9.72 over a three to four year time frame, compared to the current two-year span to help mitigate the impact on customer bills. In Arkansas, the utility implemented its new fuel rates which went into effect on November 1st. The increases will recover $40 million over the next 17 months.

We see earnings declining through 2023. Management continues to expect long-term share-earnings growth of 5%-7% annually, based off 2021 profits. (Excluding equity income.) For 2022, the company expects share earnings in a range of $2.08-$2.12 a share. Our full-year 2022 and 2023 bottom-line estimates are $2.25 a share (including equity income from Energy Transfer stake), and $2.10 a share, respectively. We have lowered our 2023 forecasts due to the macroeconomic climate, including margin pressures from rising interest rates, along with depreciation rates and pending rate reviews.

In the third quarter, OGE completed its transformation to an electric utility, after selling its Energy Transfer units. The exit from midstream operations should reduce business risk and attract investors as it becomes a pure-play electric utility. The natural gas midstream segment has long been a weakness, and the exit should improve performance.

These shares are ranked to mirror the broader market averages in the coming six to 12 months. Equities in the utilties industry have faced immense pressure as of late due to rising interest rates. Rising Treasury yields are becoming more appealing to income-oriented investors, challenging the attractiveness of the utility industry. As a result, the stock is down more than 5% in value since our last report in September. While total return potential is below average for the 18-month and 3- to 5-year period, these shares hold an attractive dividend yield that is well above the utility average.

Zachary J. Hodgkinson *December 9, 2022*

(A) Diluted EPS. Excl. nonrecurring gains (losses): '15, (33¢); '17, $1.18; '19, (8¢); '20, ($2.95); '21, $1.32; '22, $1.06; gain on discont. ops.: '06, 20¢. '19 & '21 EPS don't sum due to rounding. Next earnings report due late Feb. **(B)** Div'ds historically paid in late Jan., Apr., July, & Oct. ■ Div'd reinvestment plan avail. **(C)** Incl. deferred charges. In '21: $6.15/sh. **(D)** In mill., adj. for split. **(E)** Rate base: Net original cost. Rate allowed on com. eq. in OK in '19: 9.5%; in AR in '18: 9.5%; earned on avg. com. eq., '21: 12.7%. Regulatory Climate: Average.

Company's Financial Strength	A
Stock's Price Stability	85
Price Growth Persistence	25
Earnings Predictability	95

PORTLAND GENERAL NYSE-POR

RECENT PRICE **42.17** | P/E RATIO **14.4** (Trailing: 15.7 Median: 18.0) | RELATIVE P/E RATIO **0.98** | DIV'D YLD **4.4%** | **VALUE LINE**

TIMELINESS 3 Raised 10/7/22
SAFETY 2 Raised 10/22/21
TECHNICAL 1 Raised 9/23/22
BETA .85 (1.00 = Market)

18-Month Target Price Range

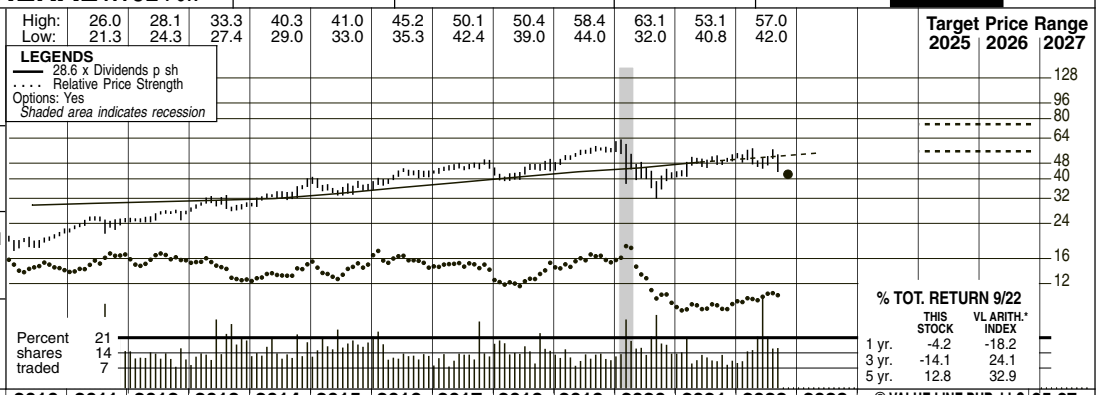
Low-High	Midpoint (% to Mid)
$44-$70	$57 (35%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+80%)	*19%*
Low	55	(+30%)	*11%*

Institutional Decisions

	4Q2021	1Q2022	2Q2022
to Buy	149	178	181
to Sell	141	142	153
Hld's(000)	81443	82974	89213



2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
24.32	27.87	27.89	23.99	23.67	24.06	23.89	23.18	24.29	21.38	21.62	22.54	22.30	23.75	23.96	26.80	*27.35*	*28.20*	Revenues per sh	*30.75*
4.64	5.21	4.71	4.07	4.82	4.96	5.15	4.93	6.08	5.37	5.78	6.16	6.65	6.97	7.83	7.25	*7.60*	*8.05*	"Cash Flow" per sh	*9.40*
1.14	2.33	1.39	1.31	1.66	1.95	1.87	1.77	2.18	2.04	2.16	2.29	2.37	2.39	2.75	2.72	*2.80*	*2.95*	Earnings per sh [A]	*3.45*
.68	.93	.97	1.01	1.04	1.06	1.08	1.10	1.12	1.18	1.26	1.34	1.43	1.52	1.59	1.70	*1.79*	*1.89*	Div'd Decl'd per sh [B] ■ †	*2.24*
5.94	7.28	6.12	9.25	5.97	3.98	4.01	8.40	12.87	6.73	6.57	5.77	6.67	6.78	8.76	7.11	*7.65*	*7.55*	Cap'l Spending per sh	*7.60*
19.58	21.05	21.64	20.50	21.14	22.07	22.87	23.30	24.43	25.43	26.35	27.11	28.07	28.99	29.18	30.28	*31.25*	*32.35*	Book Value per sh [C]	*35.80*
62.50	62.53	62.58	75.21	75.32	75.36	75.56	78.09	78.23	88.79	88.95	89.11	89.27	89.39	89.54	89.41	*89.50*	*89.50*	Common Shs Outst'g [D]	*89.50*
23.4	11.9	16.3	14.4	12.0	12.4	14.0	16.9	15.3	17.7	19.1	20.0	18.4	22.3	16.6	17.7	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*18.5*
1.26	.63	.98	.96	.76	.78	.89	.95	.81	.89	1.00	1.01	.99	1.19	.85	.95			Relative P/E Ratio	*1.05*
2.5%	3.3%	4.3%	5.4%	5.2%	4.4%	4.1%	3.7%	3.3%	3.3%	3.1%	2.9%	3.3%	2.8%	3.5%	3.5%			Avg Ann'l Div'd Yield	*3.5%*
1805.0	1810.0	1900.0	1898.0	1923.0	2009.0	1991.0	2123.0	2145.0	2396.0	*2450*	*2525*	Revenues ($mill)	*2750*
141.0	137.0	175.0	172.0	193.0	204.0	212.0	214.0	247.0	244.0	*250*	*265*	Net Profit ($mill)	*310*
31.4%	23.2%	26.0%	20.7%	20.6%	25.3%	7.4%	11.2%	12.4%	8.6%	*17.5%*	*17.5%*	Income Tax Rate	*17.5%*
7.1%	14.6%	33.7%	19.8%	16.6%	8.8%	8.0%	7.0%	9.7%	10.2%	*10.0%*	*9.0%*	AFUDC % to Net Profit	*8.0%*
47.1%	51.3%	52.7%	47.8%	48.4%	50.1%	46.5%	51.3%	53.6%	56.8%	*55.5%*	*56.0%*	Long-Term Debt Ratio	*57.5%*
52.9%	48.7%	47.3%	52.2%	51.6%	49.9%	53.5%	48.7%	46.4%	43.2%	*44.5%*	*44.0%*	Common Equity Ratio	*42.5%*
3264.0	3735.0	4037.0	4329.0	4544.0	4842.0	4684.0	5323.0	5628.0	6265.0	*6315*	*6565*	Total Capital ($mill)	*7575*
4392.0	4880.0	5679.0	6012.0	6434.0	6741.0	6887.0	7161.0	7539.0	8005.0	*8260*	*8480*	Net Plant ($mill)	*9000*
5.9%	5.1%	5.8%	5.4%	5.6%	5.5%	5.8%	5.1%	5.6%	4.9%	*5.0%*	*5.0%*	Return on Total Cap'l	*5.0%*
8.2%	7.5%	9.2%	7.6%	8.2%	8.4%	8.5%	8.3%	9.5%	9.0%	*9.0%*	*9.0%*	Return on Shr. Equity	*9.5%*
8.2%	7.5%	9.2%	7.6%	8.2%	8.4%	8.5%	8.3%	9.5%	9.0%	*9.0%*	*9.0%*	Return on Com Equity [E]	*9.5%*
3.5%	2.9%	4.6%	3.3%	3.5%	3.6%	3.5%	3.1%	4.1%	3.5%	*3.0%*	*3.5%*	Retained to Com Eq	*3.5%*
57%	61%	50%	56%	57%	58%	59%	63%	57%	61%	*64%*	*64%*	All Div'ds to Net Prof	*65%*

CAPITAL STRUCTURE as of 6/30/22
Total Debt $3604 mill. **Due in 5 Yrs** $186 mill.
LT Debt $3583 mill. **LT Interest** $128 mill.
Incl. $273 mill. finance leases.
(Total Interest Coverage: 2.9x)
Leases, Uncapitalized Annual rentals $4 mill.
Pension Assets-12/21 $800 mill.
Oblig $972 mill.
Pfd Stock None

Common Stock 89,242,847 shs.
as of 7/21/22

MARKET CAP: $3.8 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	+1.2	+.4	+5.1
Avg. Indust. Use (MWH)	17827	18472	20002
Avg. Indust. Revs. per KWH (¢)	4.75	4.99	5.22
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	3765	3771	4447
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.1	+1.5	+.6
Fixed Charge Cov. (%)	265	187	261

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	0.5%	2.0%	*3.5%*
"Cash Flow"	5.0%	5.0%	*4.0%*
Earnings	5.0%	4.5%	*4.5%*
Dividends	4.5%	6.0%	*6.0%*
Book Value	3.5%	3.0%	*3.5%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	573.0	460.0	542.0	548.0	2123.0
2020	573.0	469.0	547.0	556.0	2145.0
2021	609.0	537.0	642.0	608.0	2396.0
2022	626.0	591.0	*633*	*600*	*2450*
2023	*645*	*580*	*660*	*640*	*2525*

EARNINGS PER SHARE [A]

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.82	.28	.61	.68	2.39
2020	.91	.43	.84	.57	2.75
2021	1.07	.36	.56	.73	2.72
2022	.67	.72	*.65*	*.76*	*2.80*
2023	*.80*	*.65*	*.70*	*.80*	*2.95*

QUARTERLY DIVIDENDS PAID [B] ■ †

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.34	.34	.3625	.3625	1.41
2019	.3625	.3625	.385	.385	1.50
2020	.385	.385	.385	.4075	1.56
2021	.4075	.4075	.43	.43	1.68
2022	.43	.43	.4525	.4525	

BUSINESS: Portland General Electric Company (PGE) provides electricity to 917,000 customers in 51 cities in a 4,000-square-mile area of Oregon, including Portland and Salem (population: 1.9 million). The company is in the process of decommissioning the Trojan nuclear plant, which it closed in 1993. Electric revenue breakdown: residential, 47%; commercial, 29%; industrial, 11%; other, 13%. Generating sources: gas, 37%; wind, 9%; coal, 8%; hydro, 4%; purchased, 42%. Fuel costs: 34% of revenues. '21 reported depreciation rate: 3.4%. Has 2,800 full-time employees. Chairman: Jack E. Davis. President and Chief Executive Officer: Maria M. Pope. Incorporated: Oregon. Address: 121 S.W. Salmon Street, Portland, OR 97204. Tel.: 503-464-8000. Internet: www.portlandgeneral.com.

Portland General Electric (PGE) is having a good year, prompting management to lift guidance. To briefly recap, PGE received its general rate case decision from OPUC (Oregon Public Utility Commission) in late April, authorizing a 3.2% price hike. And during the first half of the year, the company profited from higher retail energy deliveries, due to continued growth in industrial demand, including high-tech and digital customers. PGE revised its 2022 GAAP-based share-earnings guidance up by a dime on both sides of the range, to $2.60-$2.75. Our estimate is higher, as we're excluding deferral reductions related to year ended 2020.

The utility is still awaiting finalized decisions on its RFP (request for proposals). PGE wants to add at least 375 to 500 megawatts of renewables and "nonemitting" capacity. In July, OPUC acknowledged PGE's submitted shortlist of bids in the pending RFP. The proposals provide various combinations of wind, solar, and battery storage options that include power purchase agreements along with company-owned resources. The goal remains for contracts to be executed with the winning bidders by year end.

PGE leadership's long-term earnings growth target of 4%-6% looks achievable. Next year will benefit from a full year of rate relief against an easy comparison. From 2023 out to mid-decade we're projecting a 5.5% growth rate in earnings. Accelerating load growth, thanks to the healthy economy of the utility's service territory, where there is a vibrant tech sector, is a key factor.

The board of directors raised the payout 5.2% this year. PGE targets a long-term growth rate of 5%-7% and a payout ratio of 60%-70%. Our projections assume a 6% rate of growth to mid-decade.

Utility investors may want to consider this issue for a long-term holding. Neutrally ranked PGE offers a healthy dividend yield that's 40 basis points above the electric utility median. This despite EPS and dividend growth rates being decently above the industry averages. Market weakness has the stock down 13% since our July report, and near the bottom of our 18-month Target Price Range, thereby offering solid recovery potential.

Anthony J. Glennon *October 21, 2022*

Company's Financial Strength	B++
Stock's Price Stability	90
Price Growth Persistence	65
Earnings Predictability	95

(A) Diluted earnings. Excl. nonrecurring gains/(losses): '13, (42¢); '17, (19¢); '20, ($1.03); '22, (14¢). Next earnings report due October 25th.
(B) Dividends paid mid-Jan., Apr., July, and Oct. ■ Dividend reinvestment plan available. † Shareholder investment plan available.
(C) Incl. deferred charges. In '21: $533 mill., $5.96/sh. **(D)** In mill.
(E) Rate base: Net original cost. Rate allowed on common equity in '22: 9.5%. Regulatory Climate: Average.

XCEL ENERGY NDQ-XEL

RECENT PRICE **60.21** | P/E RATIO **18.8** (Trailing: 20.0 Median: 19.0) | RELATIVE P/E RATIO **1.28** | DIV'D YLD **3.4%** | **VALUE LINE**

TIMELINESS 3 Raised 12/31/21
SAFETY 1 Raised 5/1/15
TECHNICAL 1 Raised 10/21/22
BETA .80 (1.00 = Market)

18-Month Target Price Range

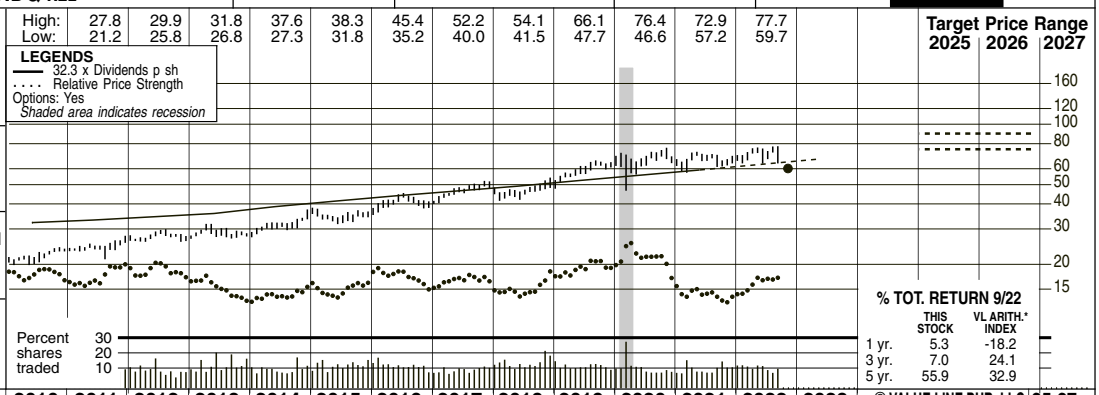
Low-High	Midpoint (% to Mid)
$64-$99	$82 (35%)

2025-27 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	90	(+50%)	*13%*
Low	75	(+25%)	*9%*

Institutional Decisions

	4Q2021	1Q2022	2Q2022
to Buy	449	458	453
to Sell	338	340	368
Hld's(000)	413762	418018	424573



2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	© VALUE LINE PUB. LLC	25-27
24.16	23.40	24.69	21.08	21.38	21.90	20.76	21.92	23.11	21.72	21.90	22.46	22.44	21.98	21.45	24.69	*25.90*	*26.35*	Revenues per sh	*28.50*
3.61	3.45	3.50	3.48	3.51	3.79	4.00	4.10	4.28	4.56	5.04	5.47	5.92	6.25	6.61	7.08	*7.75*	*8.30*	"Cash Flow" per sh	*10.00*
1.35	1.35	1.46	1.49	1.56	1.72	1.85	1.91	2.03	2.10	2.21	2.30	2.47	2.64	2.79	2.96	*3.15*	*3.35*	Earnings per sh A	*4.00*
.88	.91	.94	.97	1.00	1.03	1.07	1.11	1.20	1.28	1.36	1.44	1.52	1.62	1.72	1.83	*1.95*	*2.08*	Div'd Decl'd per sh B ■ †	*2.50*
4.00	4.89	4.66	3.91	4.60	4.53	5.27	6.82	6.33	7.26	6.42	6.54	7.70	8.05	9.99	7.80	*9.65*	*9.00*	Cap'l Spending per sh	*9.00*
14.28	14.70	15.35	15.92	16.76	17.44	18.19	19.21	20.20	20.89	21.73	22.56	23.78	25.24	27.12	28.70	*30.15*	*31.65*	Book Value per sh C	*37.00*
407.30	428.78	453.79	457.51	482.33	486.49	487.96	497.97	505.73	507.54	507.22	507.76	514.04	524.54	537.44	544.03	*547.00*	*550.00*	Common Shs Outst'g D	*561.00*
14.8	16.7	13.7	12.7	14.1	14.2	14.8	15.0	15.4	16.5	18.5	20.2	18.9	22.3	23.9	22.5	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*20.0*
.80	.89	.82	.85	.90	.89	.94	.84	.81	.83	.97	1.02	1.02	1.19	1.23	1.23			Relative P/E Ratio	*1.10*
4.4%	4.0%	4.7%	5.1%	4.5%	4.2%	3.9%	3.9%	3.8%	3.7%	3.3%	3.1%	3.3%	2.7%	2.6%	2.8%			Avg Ann'l Div'd Yield	*3.1%*
10128	10915	11686	11024	11107	11404	11537	11529	11526	13431	*14175*	*14500*	Revenues ($mill)	*16000*
905.2	948.2	1021.3	1063.6	1123.4	1171.0	1261.0	1372.0	1473.0	1597.0	*1720*	*1855*	Net Profit ($mill)	*2260*
33.2%	33.8%	33.9%	35.8%	34.1%	30.7%	12.6%	8.5%	8.5%	--	*NMF*	*NMF*	Income Tax Rate	*NMF*
10.8%	13.4%	12.5%	7.7%	7.8%	9.4%	12.4%	8.3%	10.7%	6.2%	*7.0%*	*6.0%*	AFUDC % to Net Profit	*5.0%*
53.3%	53.3%	53.0%	54.1%	56.3%	55.9%	56.4%	56.8%	57.4%	58.2%	*58.0%*	*58.0%*	Long-Term Debt Ratio	*58.0%*
46.7%	46.7%	47.0%	45.9%	43.7%	44.1%	43.6%	43.2%	42.6%	41.8%	*42.0%*	*42.0%*	Common Equity Ratio	*42.0%*
19018	20477	21714	23092	25216	25975	28025	30646	34220	37391	*39150*	*41600*	Total Capital ($mill)	*49200*
23809	26122	28757	31206	32842	34329	36944	39483	42950	45457	*48225*	*50475*	Net Plant ($mill)	*57000*
6.1%	6.0%	6.0%	5.8%	5.7%	5.8%	5.7%	5.6%	5.4%	5.3%	*5.5%*	*5.5%*	Return on Total Cap'l	*5.5%*
10.2%	9.9%	10.0%	10.0%	10.2%	10.2%	10.3%	10.4%	10.1%	10.2%	*10.5%*	*10.5%*	Return on Shr. Equity	*11.0%*
10.2%	9.9%	10.0%	10.0%	10.2%	10.2%	10.3%	10.4%	10.1%	10.2%	*10.5%*	*10.5%*	Return on Com Equity E	*11.0%*
4.7%	4.5%	4.5%	4.3%	4.0%	3.9%	4.3%	4.4%	4.2%	4.2%	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
54%	54%	55%	57%	61%	62%	58%	58%	58%	59%	*62%*	*62%*	All Div'ds to Net Prof	*62%*

CAPITAL STRUCTURE as of 6/30/22
Total Debt $23992 mill. **Due in 5 Yrs** $4911 mill.
LT Debt $23205 mill. **LT Interest** $809 mill.
Incl. $73 mill. finance leases.
(Total Interest Coverage: 2.9x)

Leases, Uncapitalized Annual rentals $69 mill.
Pension Assets-12/21 $3670 mill.
Oblig $3718 mill.
Pfd Stock None

Common Stock 546,991,330 shs.
as of 7/21/22
MARKET CAP: $32.9 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2019	2020	2021
% Change Retail Sales (KWH)	-1.2	-2.3	+1.4
Large C & I Use (MWH)	NA	NA	NA
Large C & I Revs. per KWH (¢)	5.96	5.78	6.60
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	20146	19665	19849
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+1.0	NA	NA
Fixed Charge Cov. (%)	272	252	262

ANNUAL RATES of change (per sh)

	Past 10 Yrs.	Past 5 Yrs.	Est'd '19-'21 to '25-'27
Revenues	.5%	.5%	*4.0%*
"Cash Flow"	6.5%	7.5%	*7.0%*
Earnings	6.0%	6.0%	*6.0%*
Dividends	5.5%	6.0%	*6.5%*
Book Value	5.0%	5.0%	*5.5%*

QUARTERLY REVENUES ($ mill.)

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	3141	2577	3013	2798	11529
2020	2811	2586	3182	2947	11526
2021	3541	3068	3467	3355	13431
2022	3751	3424	*3900*	*3100*	*14175*
2023	*3875*	*3450*	*4000*	*3175*	*14500*

EARNINGS PER SHARE A

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2019	.61	.46	1.01	.56	2.64
2020	.56	.54	1.14	.54	2.79
2021	.67	.58	1.13	.58	2.96
2022	.70	.60	*1.23*	*.62*	*3.15*
2023	*.75*	*.65*	*1.30*	*.65*	*3.35*

QUARTERLY DIVIDENDS PAID B ■ †

Calendar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2018	.36	.38	.38	.38	1.50
2019	.38	.405	.405	.405	1.60
2020	.405	.43	.43	.43	1.70
2021	.43	.4575	.4575	.4575	1.80
2022	.4575	.4875	.4875	.4875	

BUSINESS: Xcel Energy Inc. is the parent of Northern States Power Company (NSP), which supplies electricity to MN, WI, ND, SD & MI & gas to MN, WI, ND & MI; Public Service Company of Colorado (PSCo), which supplies electricity & gas to CO; & Southwestern Public Service Company (SPS), which supplies electricity to TX and NM. Customers: 3.7 mill. electric, 2.1 mill. gas. Electric revenue breakdown: residential, 31%; small comm'l & ind'l, 36%; large comm'l & ind'l, 18%; other, 15%. Generating sources not available. Fuel costs: 43% of revenues. '21 reported deprec. rate: 3.5%. Has 11,300 employees. Chrmn: Ben Fowke. Pres. & CEO: Bob Frenzel. Inc.: MN. Address: 414 Nicollet Mall, Minneapolis, MN 55401. Tel.: 612-330-5500. Internet: www.xcelenergy.com.

At Xcel Energy, rate relief should continue to drive steady earnings gains. Upcoming price hikes will be largely due to the approval of renewable-energy projects inclusion in the rate base, for which regulated utilities are allowed to earn a specified return on equity (ROE). The company is also effectively controlling costs despite inflationary headwinds. Our 2022 earnings estimate remains at the midpoint of Xcel's reaffirmed guidance of $3.10-$3.20 per share, given that first-half results were in line with expectations. (Entering this year our first-half share-net estimate tally was $1.33; Xcel earned $1.30 per share.) Meanwhile, our projections for 6%-6.5% profit gains in 2023 and beyond are based on the same factors. Namely, growing the rate base at its utility subsidiaries as Xcel works with its regulatory commissions to bring about a green-energy future. Company leadership has a stated earnings and dividend growth objective of 5%-7% and a solid track record that underscores its goal (see Annual Rates box). Notably, a consistently solid ROE has been delivered during both good and difficult economic times.

Xcel has numerous renewable-energy proposals up for review. The Colorado commission approved Xcel's resource plan, which includes about 4,000 megawatts (mw) of renewable (e.g., wind and solar) additions and the conversion of a major plant from coal to natural gas. This is in addition to the approved Minnesota plan, which adds 6,000 mw of renewables. RFPs (request for proposals) are being filed and commission decisions on the finer details are expected in the second half of next year. In the electric-vehicle (EV) arena, Xcel is making progress on its goal to power 1.5 million EVs by 2030. It filed transportation plans in Minnesota and Wisconsin in the third quarter. The company is looking to accelerate EV adoption through the development of high-speed public charging infrastructure in partnership with its states.

This high-quality issue offers utility investors solid risk-adjusted 3- to 5-year total returns. Its valuation is down 14% since our July report. The stock has significant recovery potential to the midpoint of our 18-month Target Price Range.

Anthony J. Glennon *October 21, 2022*

(A) Diluted EPS. Excl. nonrecurring gain (losses): '10, 5¢; '15, (16¢); '17, (5¢); gains (loss) on discontinued ops.: '06, 1¢; '09, (1¢); '10, 1¢. '20 EPS don't sum due to rounding. Next earnings report due late October. **(B)** Div'ds historically paid mid-Jan., Apr., July, and Oct. ■ Div'd reinvestment plan available. † Shareholder investment plan available. **(C)** Incl. intangibles. In '21: $2738 mill., $4.42/sh. **(D)** In mill. **(E)** Rate base: Varies. Rate allowed on common equity (blended): 9.6%. Regulatory Climate: Average.

Company's Financial Strength	A+
Stock's Price Stability	95
Price Growth Persistence	90
Earnings Predictability	100

Jersey Central Power & Light Company
Summary of Risk Premium Models for the
Proxy Group of Thirteen Electric Utilities

	Proxy Group of Thirteen Electric Utilities
Predictive Risk Premium Model (PRPM) (1)	11.95 %
Risk Premium Using an Adjusted Total Market Approach (2)	11.33
Average	11.64 %

Notes:
(1) From page 2 of this Schedule.
(2) From page 3 of this Schedule.

Jersey Central Power & Light Company
Indicated ROE
Derived by the Predictive Risk Premium Model (1)

Proxy Group of Thirteen Electric Utilities	[1] LT Average Predicted Variance	[2] Spot Predicted Variance	[3] Recommended Variance (2)	[4] GARCH Coefficient	[5] Predicted Risk Premium (3)	[6] Risk-Free Rate (4)	[7] Indicated ROE (5)
Alliant Energy Corporation	0.28%	0.43%	0.28%	2.5640	8.84%	3.91%	12.75%
Ameren Corporation	0.23%	0.35%	0.23%	2.0106	5.77%	3.91%	9.68%
American Electric Power Corporation	0.29%	0.44%	0.29%	2.3326	8.35%	3.91%	12.26%
Duke Energy Corporation	0.31%	0.40%	0.31%	1.8383	7.14%	3.91%	11.05%
Edison International	0.43%	0.65%	0.43%	1.4762	7.98%	3.91%	11.89%
Entergy Corporation	0.40%	0.51%	0.40%	2.2043	11.22%	3.91%	15.13%
Evergy, Inc.	0.49%	0.84%	0.49%	1.3060	7.99%	3.91%	11.90%
Eversource Energy	0.31%	0.46%	0.31%	1.6024	6.15%	3.91%	10.06%
IDACORP, Inc.	0.29%	0.34%	0.29%	2.1876	7.85%	3.91%	11.76%
NorthWestern Corporation	0.34%	0.53%	0.34%	2.2110	9.28%	3.91%	13.19%
OGE Energy Corporation	0.31%	0.41%	0.31%	2.1939	8.46%	3.91%	12.37%
Portland General Electric Company	0.30%	0.56%	0.30%	1.6998	6.39%	3.91%	10.30%
Xcel Energy Inc.	0.28%	0.37%	0.28%	2.7770	9.62%	3.91%	13.53%
						Average	11.99%
						Median	11.90%
						Average of Mean and Median	11.95%

Notes:
(1) The Predictive Risk Premium Model uses historical data to generate a predicted variance and a GARCH coefficient. The historical data used are the equity risk premiums for the first available trading month as reported by Bloomberg Professional Service.
(2) In view of the current increased volatility, Mr. D'Ascendis recommends the long-term predicted variance at this time.
(3) $(1+(\text{Column [3]} * \text{Column [4]})^{\wedge 12}) - 1$.
(4) From note 2 on page 2 of Schedule DWD-4.
(5) Column [5] + Column [6].

Jersey Central Power & Light Company
Indicated Common Equity Cost Rate
Through Use of a Risk Premium Model
Using an Adjusted Total Market Approach

Line No.		Proxy Group of Thirteen Electric Utilities
1.	Prospective Yield on Aaa Rated Corporate Bonds (1)	5.05 %
2.	Adjustment to Reflect Yield Spread Between Aaa Rated Corporate Bonds and A2 Rated Public Utility Bonds (2)	0.83
3.	Adjusted Prospective Yield on A2 Rated Public Utility Bonds	5.88 %
4.	Adjustment to Reflect Bond Rating Difference of Proxy Group (3)	0.20
5.	Adjusted Prospective Bond Yield	6.08 %
6.	Equity Risk Premium (4)	5.25
7.	Risk Premium Derived Common Equity Cost Rate	11.33 %

Notes:
(1) Consensus forecast of Moody's Aaa Rated Corporate bonds from Blue Chip Financial Forecasts (see pages 10 and 11 of this Schedule).
(2) The average yield spread of A2 rated public utility bonds over Aaa rated corporate bonds of 0.83% from page 4 of this Schedule.
(3) Adjustment to reflect the Baa1 Moody's LT issuer rating of the Utility Proxy Group as shown on page 5 of this Schedule. The 0.20% upward adjustment is derived by taking 2/3 of the spread between A2 and Baa2 Public Utility Bonds (2/3 * 0.30%) = 0.20%) as derived from page 4 of this Schedule.
(4) From page 7 of this Schedule.

Jersey Central Power & Light Company
Interest Rates and Bond Spreads for
Moody's Corporate and Public Utility Bonds

Selected Bond Yields

	[1] Aaa Rated Corporate Bond	[2] A2 Rated Public Utility Bond	[3] Baa2 Rated Public Utility Bond
Dec-2022	4.41 %	5.27 %	5.56 %
Nov-2022	4.90	5.75	6.05
Oct-2022	5.10	5.88	6.18
Average	4.80 %	5.63 %	5.93 %

Selected Bond Spreads

A2 Rated Public Utility Bonds Over Aaa Rated Corporate Bonds:
0.83 % (1)

Baa2 Rated Public Utility Bonds Over A2 Rated Public Utility Bonds:
0.30 % (2)

Notes:
(1) Column [2] - Column [1].
(2) Column [3] - Column [2].

Source of Information:
Bloomberg Professional Services

Jersey Central Power & Light Company
Comparison of Long-Term Issuer Ratings for
Proxy Group of Thirteen Electric Utilities

	Moody's		Standard & Poor's	
	Long-Term Issuer Rating December 2022		Long-Term Issuer Rating December 2022	
Proxy Group of Thirteen Electric Utilities (2)	Long-Term Issuer Rating	Numerical Weighting (1)	Long-Term Issuer Rating	Numerical Weighting (1)
Alliant Energy Corporation	A3/Baa1	7.5	A/A-	6.5
Ameren Corporation	A3	7.0	BBB+	8.0
American Electric Power Corporation	Baa1	8.0	A-	7.0
Duke Energy Corporation	A3	7.0	BBB+	8.0
Edison International	Baa2	9.0	BBB	9.0
Entergy Corporation	Baa1	8.0	BBB+	8.0
Evergy, Inc.	Baa1	8.0	A-	7.0
Eversource Energy	A3	7.0	A-	7.0
IDACORP, Inc.	Baa1	8.0	BBB	9.0
NorthWestern Corporation	Baa2	9.0	BBB	9.0
OGE Energy Corporation	A3	7.0	A-	7.0
Portland General Electric Company	A3	7.0	BBB+	8.0
Xcel Energy Inc.	A3	7.0	A-	7.0
Average	Baa1	7.7	BBB+	7.7

Notes:
(1) From page 6 of this Schedule.
(2) Based on the ratings of the utility operating subsidaries of the Utility Proxy Group.

Source of Information: Moody's Investors Service
Standard & Poor's Global Utilities Rating Service

Numerical Assignment for
Moody's and Standard & Poor's Bond Ratings

Moody's Bond Rating	Numerical Bond Weighting	Standard & Poor's Bond Rating
Aaa	1	AAA
Aa1	2	AA+
Aa2	3	AA
Aa3	4	AA-
A1	5	A+
A2	6	A
A3	7	A-
Baa1	8	BBB+
Baa2	9	BBB
Baa3	10	BBB-
Ba1	11	BB+
Ba2	12	BB
Ba3	13	BB-
B1	14	B+
B2	15	B
B3	16	B-

Jersey Central Power & Light Company
Judgment of Equity Risk Premium for the
Proxy Group of Thirteen Electric Utilities

Line No.		Proxy Group of Thirteen Electric Utilities
1.	Calculated equity risk premium based on the total market using the beta approach (1)	6.67 %
2.	Mean equity risk premium based on a study using the holding period returns of public utilities with A2 rated bonds (2)	4.32
3.	Predicted Equity Risk Premium Based on Regression Analysis of 1207 Fully-Litigated Electric Utility Rate Cases (3)	4.77
4.	Average equity risk premium	5.25 %

Notes: (1) From page 8 of this Schedule.
(2) From page 12 of this Schedule.
(3) From pages 13 of this Schedule.

Jersey Central Power & Light Company
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for the
Proxy Group of Thirteen Electric Utilities

Line No.	Equity Risk Premium Measure	Proxy Group of Thirteen Electric Utilities
1.	Kroll Equity Risk Premium (1)	6.13 %
2.	Regression on Kroll Risk Premium Data (2)	7.26
3.	Kroll Equity Risk Premium based on PRPM (3)	9.76
4.	Equity Risk Premium Based on Value Line Summary and Index (4)	11.53
5.	Equity Risk Premium Based on Value Line S&P 500 Companies (5)	10.62
6.	Equity Risk Premium Based on Bloomberg S&P 500 Companies (6)	6.01
7.	Conclusion of Equity Risk Premium	8.55 %
8.	Adjusted Beta (7)	0.78
9.	Forecasted Equity Risk Premium	6.67 %

Notes provided on page 9 of this Schedule.

Jersey Central Power & Light Company
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for the
Proxy Group of Thirteen Electric Utilities

Notes:

(1) Based on the arithmetic mean historical monthly returns on large company common stocks from Kroll 2022 SBBI® Yearbook minus the arithmetic mean monthly yield of Moody's average Aaa and Aa corporate bonds from 1928-2021.

(2) This equity risk premium is based on a regression of the monthly equity risk premiums of large company common stocks relative to Moody's average Aaa and Aa2 rated corporate bond yields from 1928-2021 referenced in Note 1 above.

(3) The Predictive Risk Premium Model (PRPM) is discussed in the accompanying direct testimony. The SBBI equity risk premium based on the PRPM is derived by applying the PRPM to the monthly risk premiums between SBBI large company common stock monthly returns and average Aaa and Aa2 corporate monthly bond yields, from January 1928 through December 2022.

(4) The equity risk premium based on the Value Line Summary and Index is derived by subtracting the average consensus forecast of Aaa corporate bonds of 5.05% (from page 3 of this Schedule) from the projected 3-5 year total annual market return of 16.58% (described fully in note 1 on page 2 of Schedule DWD-4).

(5) Using data from Value Line for the S&P 500, an expected total return of 15.67% was derived based upon expected dividend yields and long-term earnings growth estimates as a proxy for capital appreciation. Subtracting the average consensus forecast of Aaa corporate bonds of 5.05% results in an expected equity risk premium of 10.62%.

(6) Using data from Bloomberg for the S&P 500, an expected total return of 11.06% was derived based upon expected dividend yields and long-term earnings growth estimates as a proxy for capital appreciation. Subtracting the average consensus forecast of Aaa corporate bonds of 5.05% results in an expected equity risk premium of 6.01%.

(7) Average of mean and median beta from Schedule DWD-4.

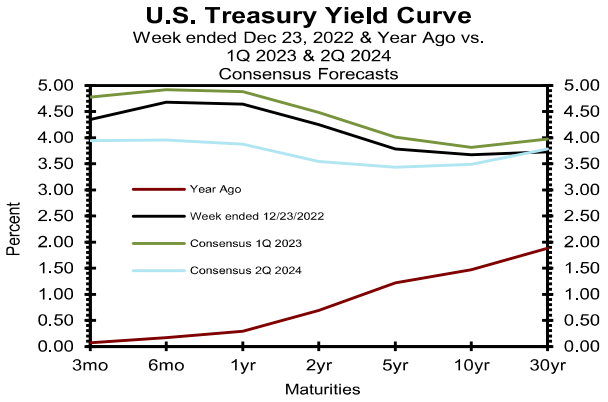
Sources of Information:

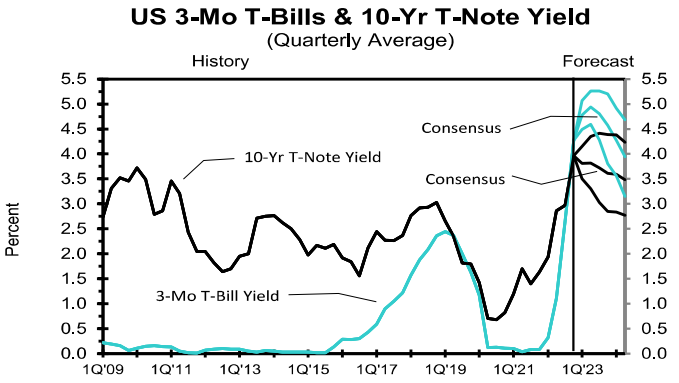
Stocks, Bonds, Bills, and Inflation - 2022 SBBI Yearbook, Kroll, Inc.
Industrial Manual and Mergent Bond Record Monthly Update.
Value Line Summary and Index.
Blue Chip Financial Forecasts, January 1, 2023 and December 2, 2022
Bloomberg Professional Services.

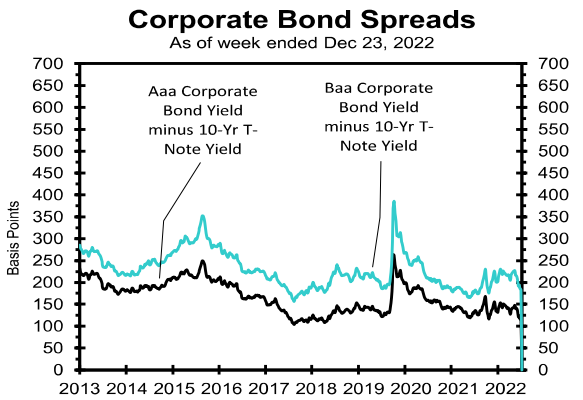
Consensus Forecasts of U.S. Interest Rates and Key Assumptions

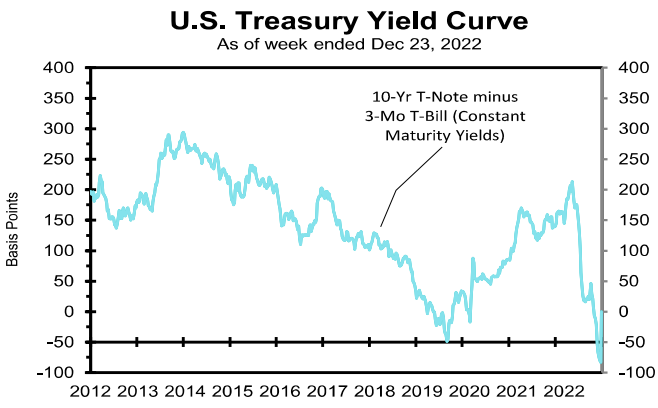
	History								Consensus Forecasts-Quarterly Avg.					
	Average For Week Ending				Average For Month			*Latest Qtr*	1Q	2Q	3Q	4Q	1Q	2Q
Interest Rates	Dec 23	Dec 16	Dec 9	Dec 2	Nov	Oct	Sep	4Q 2022*	2023	2023	2023	2023	2024	2024
Federal Funds Rate	4.33	3.83	3.83	3.83	3.78	3.08	2.56	3.59	**4.7**	**5.0**	**4.9**	**4.7**	**4.4**	**4.0**
Prime Rate	7.50	7.00	7.00	7.00	6.95	6.25	5.73	6.76	**7.8**	**8.1**	**8.0**	**7.8**	**7.5**	**7.2**
SOFR	4.30	4.01	3.80	3.81	3.73	3.04	2.50	3.55	**4.6**	**4.9**	**4.8**	**4.6**	**4.4**	**4.1**
Commercial Paper, 1-mo.	4.28	4.23	4.15	4.00	3.88	3.28	2.80	3.71	**4.8**	**5.1**	**4.9**	**4.6**	**4.4**	**4.0**
Treasury bill, 3-mo.	4.35	4.34	4.32	4.37	4.32	3.87	3.22	4.17	**4.8**	**4.9**	**4.8**	**4.6**	**4.3**	**3.9**
Treasury bill, 6-mo.	4.68	4.71	4.72	4.69	4.61	4.31	3.71	4.53	**4.9**	**5.0**	**4.8**	**4.5**	**4.3**	**4.0**
Treasury bill, 1 yr.	4.64	4.66	4.72	4.73	4.73	4.43	3.89	4.61	**4.9**	**4.9**	**4.7**	**4.4**	**4.2**	**3.9**
Treasury note, 2 yr.	4.25	4.25	4.33	4.37	4.50	4.38	3.86	4.39	**4.5**	**4.4**	**4.2**	**3.9**	**3.8**	**3.5**
Treasury note, 5 yr.	3.78	3.67	3.72	3.79	4.06	4.18	3.70	4.00	**4.0**	**4.0**	**3.9**	**3.7**	**3.6**	**3.4**
Treasury note, 10 yr.	3.67	3.51	3.52	3.63	3.89	3.98	3.52	3.82	**3.8**	**3.8**	**3.7**	**3.6**	**3.6**	**3.5**
Treasury note, 30 yr.	3.73	3.53	3.51	3.71	4.00	4.04	3.56	3.89	**4.0**	**4.0**	**3.9**	**3.9**	**3.8**	**3.8**
Corporate Aaa bond	4.88	4.66	4.68	4.87	5.23	5.41	4.87	5.15	**5.1**	**5.2**	**5.2**	**5.1**	**4.9**	**4.8**
Corporate Baa bond	5.56	5.34	5.38	5.57	5.95	6.22	5.64	5.90	**6.1**	**6.3**	**6.2**	**6.1**	**5.9**	**5.8**
State & Local bonds	4.24	4.18	4.19	4.26	4.50	4.62	4.31	4.46	**4.3**	**4.4**	**4.3**	**4.3**	**4.3**	**4.2**
Home mortgage rate	6.27	6.31	6.33	6.49	6.81	6.90	6.11	6.69	**6.5**	**6.5**	**6.3**	**6.2**	**6.0**	**5.8**
	History								Consensus Forecasts-Quarterly					
	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q	3Q	4Q	1Q	2Q
Key Assumptions	2021	2021	2021	2021	2022	2022	2022	2022**	2023	2023	2023	2023	2024	2024
Fed's AFE $ Index	103.4	102.9	105.0	107.0	108.4	113.7	119.0	120.6	**118.7**	**118.1**	**117.6**	**117.1**	**116.8**	**116.9**
Real GDP	6.3	7.0	2.7	7.0	-1.6	-0.6	3.2	1.0	**-0.2**	**-0.7**	**0.3**	**0.9**	**1.3**	**1.7**
GDP Price Index	5.2	6.3	6.2	6.8	8.3	9.0	4.4	4.3	**3.6**	**3.0**	**2.7**	**2.5**	**2.3**	**2.2**
Consumer Price Index	4.1	8.2	6.7	7.9	9.2	10.5	5.7	4.5	**3.4**	**3.1**	**2.9**	**2.6**	**2.4**	**2.3**
PCE Price Index	4.5	6.4	5.6	6.2	7.5	7.3	4.3	4.2	**3.2**	**2.8**	**2.6**	**2.5**	**2.4**	**2.2**

Forecasts for interest rates and the Federal Reserve's Advanced Foreign Economies Index represent averages for the quarter. Forecasts for Real GDP, GDP Price Index, CPI and PCE Price Index are seasonally-adjusted annual rates of change (saar). Individual panel members' forecasts are on pages 4 through 9. Historical data: Treasury rates from the Federal Reserve Board's H.15; AAA-AA and A-BBB corporate bond yields from Bank of America-Merrill Lynch and are 15+ years, yield to maturity; State and local bond yields from Bank of America-Merrill Lynch, A-rated, yield to maturity; Mortgage rates from Freddie Mac, 30-year, fixed; SOFR from the New York Fed. *Interest rate data for 4Q 2022 based on historical data through the week ended December 23. **Data for 4Q 2022 for the Fed's AFE $ Index based on data through the week ended December 23. Figures for 4Q 2022 Real GDP, GDP Chained Price Index, Consumer Price Index, and PCE Price Index are consensus forecasts from the December 2022 survey.









Long-Range Survey:

The table below contains the results of our twice-annual long-range CONSENSUS survey. There are also Top 10 and Bottom 10 averages for each variable. Shown are consensus estimates for the years 2024 through 2028 and averages for the five-year periods 2024-2028 and 2029-2033. Apply these projections cautiously. Few if any economic, demographic and political forces can be evaluated accurately over such long time spans.

		Average For The Year					Five-Year Averages	
		2024	2025	2026	2027	2028	2024-2028	2029-2033
1. Federal Funds Rate	**CONSENSUS**	**3.7**	**2.9**	**2.8**	**2.8**	**2.7**	**3.0**	**2.8**
	Top 10 Average	4.5	3.7	3.6	3.5	3.4	3.7	3.4
	Bottom 10 Average	2.7	2.2	2.2	2.2	2.2	2.3	2.3
2. Prime Rate	**CONSENSUS**	**6.8**	**6.1**	**5.9**	**5.9**	**5.9**	**6.1**	**5.9**
	Top 10 Average	7.6	6.8	6.7	6.6	6.5	6.8	6.5
	Bottom 10 Average	5.9	5.3	5.3	5.3	5.3	5.4	5.3
3. SOFR	**CONSENSUS**	**3.7**	**2.9**	**2.8**	**2.8**	**2.7**	**3.0**	**2.8**
	Top 10 Average	4.4	3.6	3.4	3.3	3.2	3.6	3.3
	Bottom 10 Average	3.0	2.3	2.2	2.2	2.2	2.4	2.2
4. Commercial Paper, 1-Mo	**CONSENSUS**	**3.7**	**3.1**	**3.0**	**2.9**	**2.9**	**3.1**	**2.9**
	Top 10 Average	4.4	3.6	3.5	3.4	3.3	3.6	3.3
	Bottom 10 Average	3.2	2.6	2.5	2.4	2.4	2.6	2.5
5. Treasury Bill Yield, 3-Mo	**CONSENSUS**	**3.7**	**3.0**	**2.9**	**2.8**	**2.8**	**3.0**	**2.8**
	Top 10 Average	4.4	3.7	3.6	3.5	3.4	3.7	3.4
	Bottom 10 Average	2.9	2.2	2.3	2.2	2.2	2.4	2.3
6. Treasury Bill Yield, 6-Mo	**CONSENSUS**	**3.7**	**3.0**	**3.0**	**3.0**	**2.9**	**3.1**	**3.0**
	Top 10 Average	4.4	3.7	3.7	3.6	3.5	3.8	3.5
	Bottom 10 Average	3.1	2.4	2.4	2.4	2.4	2.5	2.4
7. Treasury Bill Yield, 1-Yr	**CONSENSUS**	**3.8**	**3.1**	**3.1**	**3.1**	**3.0**	**3.2**	**3.1**
	Top 10 Average	4.4	3.8	3.7	3.6	3.5	3.8	3.6
	Bottom 10 Average	3.1	2.5	2.5	2.5	2.5	2.6	2.6
8. Treasury Note Yield, 2-Yr	**CONSENSUS**	**3.6**	**3.2**	**3.2**	**3.1**	**3.1**	**3.2**	**3.1**
	Top 10 Average	4.4	3.9	3.8	3.8	3.7	3.9	3.8
	Bottom 10 Average	2.7	2.5	2.6	2.6	2.6	2.6	2.6
9. Treasury Note Yield, 5-Yr	**CONSENSUS**	**3.6**	**3.3**	**3.4**	**3.4**	**3.3**	**3.4**	**3.4**
	Top 10 Average	4.4	4.0	4.0	4.0	3.9	4.1	3.9
	Bottom 10 Average	2.9	2.7	2.7	2.8	2.8	2.8	2.9
10. Treasury Note Yield, 10-Yr	**CONSENSUS**	**3.7**	**3.5**	**3.6**	**3.6**	**3.6**	**3.6**	**3.7**
	Top 10 Average	4.4	4.2	4.4	4.4	4.3	4.3	4.3
	Bottom 10 Average	3.0	2.9	2.8	2.9	3.0	2.9	3.0
11. Treasury Bond Yield, 30-Yr	**CONSENSUS**	**4.0**	**3.9**	**3.9**	**4.0**	**3.9**	**3.9**	**4.0**
	Top 10 Average	4.6	4.5	4.7	4.6	4.6	4.6	4.7
	Bottom 10 Average	3.4	3.3	3.3	3.3	3.3	3.3	3.3
12. Corporate Aaa Bond Yield	**CONSENSUS**	**5.1**	**4.9**	**5.0**	**5.0**	**5.0**	**5.0**	**5.1**
	Top 10 Average	5.7	5.5	5.6	5.6	5.6	5.6	5.7
	Bottom 10 Average	4.6	4.4	4.4	4.4	4.5	4.4	4.5
13. Corporate Baa Bond Yield	**CONSENSUS**	**6.2**	**5.9**	**5.9**	**6.0**	**5.9**	**6.0**	**6.0**
	Top 10 Average	6.6	6.4	6.5	6.5	6.5	6.5	6.6
	Bottom 10 Average	5.7	5.3	5.3	5.4	5.4	5.4	5.5
14. State & Local Bonds Yield	**CONSENSUS**	**4.4**	**4.2**	**4.3**	**4.3**	**4.3**	**4.3**	**4.4**
	Top 10 Average	4.8	4.7	4.8	4.7	4.7	4.7	4.8
	Bottom 10 Average	3.9	3.7	3.8	3.9	3.9	3.9	3.9
15. Home Mortgage Rate	**CONSENSUS**	**5.9**	**5.5**	**5.5**	**5.5**	**5.5**	**5.6**	**5.5**
	Top 10 Average	6.6	6.2	6.2	6.2	6.2	6.3	6.2
	Bottom 10 Average	5.3	4.8	4.8	4.8	4.8	4.9	4.9
A. Fed's AFE Nominal $ Index	**CONSENSUS**	**117.6**	**116.0**	**114.5**	**113.5**	**112.2**	**114.8**	**110.7**
	Top 10 Average	120.7	119.3	118.5	118.0	117.9	118.9	116.7
	Bottom 10 Average	115.1	112.9	110.7	109.2	107.2	111.0	105.4
		Year-Over-Year, % Change					Five-Year Averages	
		2024	2025	2026	2027	2028	2024-2028	2029-2033
B. Real GDP	**CONSENSUS**	**1.4**	**2.2**	**2.1**	**2.0**	**2.0**	**1.9**	**1.9**
	Top 10 Average	2.2	2.6	2.6	2.4	2.4	2.5	2.3
	Bottom 10 Average	0.5	1.8	1.7	1.7	1.7	1.5	1.6
C. GDP Chained Price Index	**CONSENSUS**	**2.3**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**
	Top 10 Average	2.7	2.4	2.3	2.3	2.3	2.4	2.2
	Bottom 10 Average	2.0	1.9	1.9	1.9	1.9	1.9	1.9
D. Consumer Price Index	**CONSENSUS**	**2.4**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**	**2.1**
	Top 10 Average	2.8	2.5	2.4	2.3	2.3	2.5	2.3
	Bottom 10 Average	2.0	2.0	2.0	2.0	2.0	2.0	2.0
E. PCE Price Index	**CONSENSUS**	**2.3**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**
	Top 10 Average	2.6	2.4	2.4	2.3	2.2	2.4	2.2
	Bottom 10 Average	1.9	1.9	1.9	1.9	2.0	1.9	1.9

Jersey Central Power & Light Company
Derivation of Mean Equity Risk Premium Based Studies
Using Holding Period Returns and
Projected Market Appreciation of the S&P Utility Index

Line No.	Equity Risk Premium based on S&P Utility Index Holding Period Returns (1) :	Implied Equity Risk Premium
1.	Historical Equity Risk Premium	4.28 %
2.	Regression of Historical Equity Risk Premium (2)	4.80
3.	Forecasted Equity Risk Premium Based on PRPM (3)	5.56
4.	Forecasted Equity Risk Premium based on Projected Total Return on the S&P Utilities Index (Value Line Data) (4)	3.62
5.	Forecasted Equity Risk Premium based on Projected Total Return on the S&P Utilities Index (Bloomberg Data) (5)	3.32
6.	Average Equity Risk Premium (6)	4.32 %

Notes:
(1) Based on S&P Public Utility Index monthly total returns and Moody's Public Utility Bond average monthly yields from 1928-2021. Holding period returns are calculated based upon income received (dividends and interest) plus the relative change in the market value of a security over a one-year holding period.

(2) This equity risk premium is based on a regression of the monthly equity risk premiums of the S&P Utility Index relative to Moody's A2 rated public utility bond yields from 1928 - 2021 referenced in note 1 above. Using the equation generated from the regression, an expected equity risk premium is calculated using the relevant bond yield. The projected A2 rated utiliy bond yields are shown on line 3 of page 3 of this Schedule.

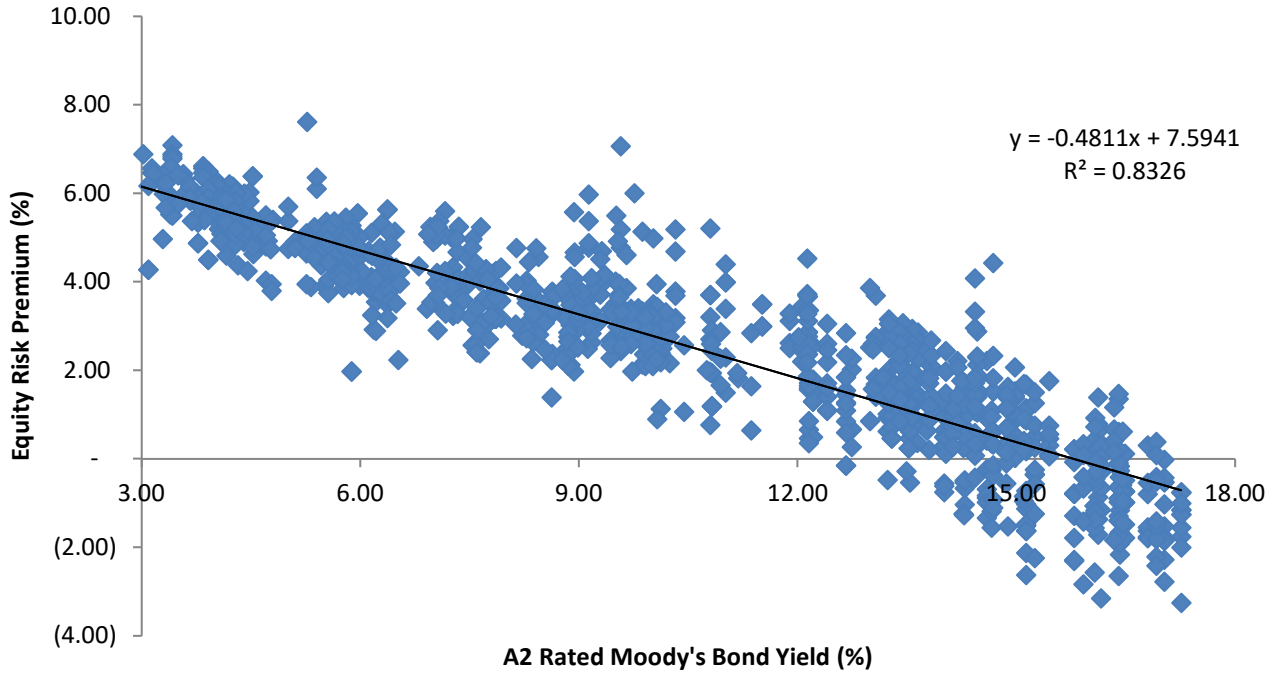
(3) The Predictive Risk Premium Model (PRPM) is applied to the risk premium of the monthly total returns of the S&P Utility Index and the monthly yields on Moody's A2 rated public utility bonds from January 1928 - December 2022.

(4) Using data from Value Line for the S&P Utilities Index, an expected return of 9.50% was derived based on expected dividend yields and long-term growth estimates as a proxy for market appreciation. Subtracting the expected A2 rated public utility bond yield of 5.88%, calculated on line 3 of page 3 of this Schedule results in an equity risk premium of 3.62%. (9.50% - 5.88% = 3.62%)

(5) Using data from Bloomberg Professional Services for the S&P Utilities Index, an expected return of 9.20% was derived based on expected dividend yields and long-term growth estimates as a proxy for market appreciation. Subtracting the expected A2 rated public utility bond yield of 5.88%, calculated on line 3 of page 3 of this Schedule results in an equity risk premium of 3.32%. (9.20% - 5.88% = 3.32%)

(6) Average of lines 1 through 5.

Jersey Central Power & Light Company
Prediction of Equity Risk Premiums Relative to
Moody's A2 Rated Utility Bond Yields - Electric Utilities



Constant	Slope	Prospective A2 Rated Utility Bond (1)	Prospective Equity Risk Premium
7.5941 %	-0.4811	5.88 %	4.77 %

Notes:

(1) From line 3 of page 3 of this Schedule.

Source of Information: Regulatory Research Associates.

Jersey Central Power & Light Company
Indicated Common Equity Cost Rate Through Use
of the Traditional Capital Asset Pricing Model (CAPM) and Empirical Capital Asset Pricing Model (ECAPM)

Proxy Group of Thirteen Electric Utilities	[1] Value Line Adjusted Beta	[2] Bloomberg Adjusted Beta	[3] Average Beta	[4] Market Risk Premium (1)	[5] Risk-Free Rate (2)	[6] Traditional CAPM Cost Rate	[7] ECAPM Cost Rate	[8] Indicated Common Equity Cost Rate (3)
Alliant Energy Corporation	0.85	0.72	0.78	9.75 %	3.91 %	11.51 %	12.05 %	11.78 %
Ameren Corporation	0.85	0.74	0.79	9.75	3.91	11.61	12.12	11.87
American Electric Power Corporation	0.75	0.66	0.71	9.75	3.91	10.83	11.54	11.19
Duke Energy Corporation	0.85	0.63	0.74	9.75	3.91	11.12	11.76	11.44
Edison International	0.95	0.83	0.89	9.75	3.91	12.59	12.86	12.72
Entergy Corporation	0.95	0.73	0.84	9.75	3.91	12.10	12.49	12.29
Evergy, Inc.	0.90	0.68	0.79	9.75	3.91	11.61	12.12	11.87
Eversource Energy	0.90	0.69	0.80	9.75	3.91	11.71	12.20	11.95
IDACORP, Inc.	0.80	0.63	0.72	9.75	3.91	10.93	11.61	11.27
NorthWestern Corporation	0.90	0.61	0.75	9.75	3.91	11.22	11.83	11.53
OGE Energy Corporation	1.00	0.75	0.88	9.75	3.91	12.49	12.78	12.64
Portland General Electric Company	0.85	0.63	0.74	9.75	3.91	11.12	11.76	11.44
Xcel Energy Inc.	0.80	0.68	0.74	9.75	3.91	11.12	11.76	11.44
Mean			0.78			11.54 %	12.07 %	11.80 %
Median			0.78			11.51 %	12.05 %	11.78 %
Average of Mean and Median			0.78			11.53	12.06	11.79 %

Notes on page 2 of this Schedule.

Jersey Central Power & Light Company
Notes to Accompany the Application of the CAPM and ECAPM

Notes:

(1) The market risk premium (MRP) is derived by using six different measures from three sources: Kroll, Value Line, and Bloomberg as illustrated below:

Historical Data MRP Estimates:

Measure 1: Kroll Arithmetic Mean MRP (1926-2021)

Arithmetic Mean Monthly Returns for Large Stocks 1926-2021:	12.37 %
Arithmetic Mean Income Returns on Long-Term Government Bonds:	5.02
MRP based on Kroll Historical Data:	7.35 %

Measure 2: Application of a Regression Analysis to Kroll Historical Data
(1926-2022) 8.71 %

Measure 3: Application of the PRPM to Kroll Historical Data:
(January 1926 - December 2022) 10.86 %

Value Line MRP Estimates:

Measure 4: Value Line Projected MRP (Thirteen weeks ending December 30, 2022)

Total projected return on the market 3-5 years hence*:	16.58 %
Projected Risk-Free Rate (see note 2):	3.91
MRP based on Value Line Summary & Index:	12.67 %

*Forcasted 3-5 year capital appreciation plus expected dividend yield

Measure 5: Value Line Projected Return on the Market based on the S&P 500

Total return on the Market based on the S&P 500:	15.67 %
Projected Risk-Free Rate (see note 2):	3.91
MRP based on Value Line data	11.76 %

Measure 6: Bloomberg Projected MRP

Total return on the Market based on the S&P 500:	11.06 %
Projected Risk-Free Rate (see note 2):	3.91
MRP based on Bloomberg data	7.15 %

Average of Value Line, Kroll, and Bloomberg MRP: 9.75 %

(2) For reasons explained in the direct testimony, the appropriate risk-free rate for cost of capital purposes is the average forecast of 30 year Treasury Bonds per the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts. (See pages 10-11 of Schedule DWD-3.) The projection of the risk-free rate is illustrated below:

First Quarter 2023	4.00 %
Second Quarter 2023	4.00
Third Quarter 2023	3.90
Fourth Quarter 2023	3.90
First Quarter 2024	3.80
Second Quarter 2024	3.80
2024-2028	3.90
2029-2033	4.00
	3.91 %

(3) Average of Column 6 and Column 7.

Sources of Information:

Value Line Summary and Index
Blue Chip Financial Forecasts, January 1, 2023 and December 2, 2022
Stocks, Bonds, Bills, and Inflation - 2022 SBBI Yearbook, Kroll, Inc.
Bloomberg Professional Services

Jersey Central Power & Light Company
Basis of Selection of the Group of Non-Price Regulated Companies
Comparable in Total Risk to the Utility Proxy Group

The criteria for selection of the Non-Price Regulated Proxy Group was that the non-price regulated companies be domestic and reported in Value Line Investment Survey (Standard Edition).

The Non-Price Regulated Proxy Group was then selected based on the unadjusted beta range of 0.65 – 0.93 and residual standard error of the regression range of 2.5574–3.0502 of the Utility Proxy Group.

These ranges are based upon plus or minus two standard deviations of the unadjusted beta and standard error of the regression. Plus or minus two standard deviations captures 95.50% of the distribution of unadjusted betas and residual standard errors of the regression.

The standard deviation of the Utility Proxy Group's residual standard error of the regression is 0.1232. The standard deviation of the standard error of the regression is calculated as follows:

$$\text{Standard Deviation of the Std. Err. of the Regr.} = \frac{\text{Standard Error of the Regression}}{\sqrt{2N}}$$

where: N = number of observations. Since Value Line betas are derived from weekly price change observations over a period of five years, N = 259

$$\text{Thus, } 0.1232 = \frac{2.8038}{\sqrt{518}} = \frac{2.8038}{22.7596}$$

Source of Information: Value Line, Inc., December 2022
Value Line Investment Survey (Standard Edition)

Jersey Central Power & Light Company
Basis of Selection of Comparable Risk
Domestic Non-Price Regulated Companies

Proxy Group of Thirteen Electric Distribution Companies	[1] Value Line Adjusted Beta	[2] Unadjusted Beta	[3] Residual Standard Error of the Regression	[4] Standard Deviation of Beta
Alliant Energy Corporation	0.85	0.71	2.7441	0.0683
Ameren Corporation	0.80	0.69	2.5700	0.0640
American Electric Power Corporation	0.75	0.59	2.6606	0.0662
Duke Energy Corporation	0.85	0.76	2.7262	0.0679
Edison International	0.95	0.91	3.2762	0.0816
Entergy Corporation	0.95	0.86	2.7816	0.0692
Evergy, Inc.	0.95	0.87	3.1310	0.0806
Eversource Energy	0.90	0.83	3.0490	0.0759
IDACORP, Inc.	0.80	0.68	2.5804	0.0642
NorthWestern Corporation	0.95	0.89	2.7689	0.0689
OGE Energy Corporation	1.05	1.05	2.6629	0.0663
Portland General Electric Company	0.90	0.79	2.8012	0.0697
Xcel Energy Inc.	0.80	0.66	2.6976	0.0672
Average	0.88	0.79	2.8038	0.0700
Beta Range (+/- 2 std. Devs. of Beta)	0.65	0.93		
2 std. Devs. of Beta	0.14			
Residual Std. Err. Range (+/- 2 std. Devs. of the Residual Std. Err.)	2.5574	3.0502		
Std. dev. of the Res. Std. Err.	0.1232			
2 std. devs. of the Res. Std. Err.	0.2464			

Source of Information: Valueline Proprietary Database, December 2022

Jersey Central Power & Light Company
Proxy Group of Non-Price Regulated Companies
Comparable in Total Risk to the
Proxy Group of Thirteen Electric Distribution Companies

Proxy Group of Fifty Non-Price Regulated Companies	[1] VL Adjusted Beta	[2] Unadjusted Beta	[3] Residual Standard Error of the Regression	[4] Standard Deviation of Beta
Agilent Technologies	0.85	0.77	2.6442	0.0658
Abbott Labs.	0.90	0.81	2.7622	0.0688
Analog Devices	0.95	0.87	2.8417	0.0707
Assurant Inc.	0.95	0.85	2.7366	0.0681
Smith (A.O.)	0.85	0.76	2.7272	0.0679
Air Products & Chem.	0.90	0.79	2.6237	0.0653
Ball Corp.	0.95	0.91	2.8314	0.0705
Brown-Forman 'B'	0.90	0.80	2.6915	0.0670
Bristol-Myers Squibb	0.85	0.76	3.0330	0.0755
Broadridge Fin'l	0.85	0.70	2.7610	0.0687
Brady Corp.	1.00	0.93	2.7641	0.0688
CACI Int'l	0.90	0.84	2.9846	0.0743
Chemed Corp.	0.85	0.70	2.7215	0.0677
Cooper Cos.	0.95	0.90	2.7720	0.0690
CSW Industrials	0.90	0.80	2.9127	0.0725
Quest Diagnostics	0.80	0.69	3.0218	0.0752
Dolby Labs.	0.95	0.88	2.6152	0.0651
Lauder (Estee)	0.95	0.92	2.9395	0.0732
Exponent, Inc.	0.90	0.80	2.8742	0.0715
FactSet Research	1.00	0.93	2.6951	0.0671
Gentex Corp.	0.95	0.90	2.7524	0.0685
Ingredion Inc.	0.90	0.85	2.8617	0.0712
Hunt (J.B.)	0.95	0.90	2.9072	0.0724
J&J Snack Foods	0.95	0.87	2.9766	0.0741
Henry (Jack) & Assoc	0.85	0.70	2.8821	0.0717
L3Harris Technologie	0.95	0.92	2.5815	0.0709
McCormick & Co.	0.80	0.66	2.8331	0.0705
Altria Group	0.95	0.88	2.9551	0.0736
MSA Safety	0.95	0.92	3.0013	0.0747
MSCI Inc.	0.95	0.85	3.0171	0.0751
Motorola Solutions	0.90	0.79	2.6757	0.0666
Mettler-Toledo Int'l	0.95	0.89	2.7628	0.0688
Northrop Grumman	0.85	0.74	2.9186	0.0727
Old Dominion Freight	0.95	0.85	2.9677	0.0739
Packaging Corp.	0.95	0.90	2.8815	0.0717
Post Holdings	0.95	0.86	2.9244	0.0728
RLI Corp.	0.80	0.66	2.8575	0.0711
Rollins, Inc.	0.85	0.72	2.9831	0.0743
Service Corp. Int'l	0.95	0.89	2.6275	0.0654
Sherwin-Williams	0.90	0.84	2.5643	0.0638
Selective Ins. Group	0.90	0.81	2.9464	0.0733
Sirius XM Holdings	0.95	0.86	2.9589	0.0737
Sensient Techn.	0.90	0.82	2.6393	0.0657
Thermo Fisher Sci.	0.85	0.70	2.6279	0.0654
Texas Instruments	0.85	0.75	2.6590	0.0662
U-Haul Holding	0.95	0.92	2.7274	0.0679
UniFirst Corp.	0.95	0.91	2.7167	0.0676
VeriSign Inc.	0.90	0.78	2.5863	0.0644
Waters Corp.	0.95	0.87	2.8032	0.0698
Watsco, Inc.	0.85	0.75	2.6936	0.0671
Average	0.91	0.82	2.8049	0.0700
Proxy Group of Thirteen Electric Distribution Companies	0.88	0.79	2.8038	0.0700

Source of Information: Value Line Proprietary Database, December 2022

Jersey Central Power & Light Company
Summary of Cost of Equity Models Applied to
Proxy Group of Fifty Non-Price Regulated Companies
Comparable in Total Risk to the
Proxy Group of Thirteen Electric Utilities

Principal Methods	Proxy Group of Fifty Non-Price Regulated Companies
Discounted Cash Flow Model (DCF) (1)	11.72 %
Risk Premium Model (RPM) (2)	13.40
Capital Asset Pricing Model (CAPM) (3)	12.59
Mean	12.57 %
Median	12.59 %
Average of Mean and Median	12.58 %

Notes:
(1) From page 2 of this Schedule.
(2) From page 3 of this Schedule.
(3) From page 6 of this Schedule.

Jersey Central Power & Light Company
DCF Results for the Proxy Group of Non-Price-Regulated Companies Comparable in Total Risk to the
Proxy Group of Thirteen Electric Utilities

	[1]	[2]	[3]	[4]	[6]	[7]	[8]
Proxy Group of Fifty Non-Price Regulated Companies	Average Dividend Yield	Value Line Projected Five Year Growth in EPS	Zack's Five Year Projected Growth Rate in EPS	Yahoo! Finance Projected Five Year Growth in EPS	Average Projected Five Year Growth Rate in EPS	Adjusted Dividend Yield	Indicated Common Equity Cost Rate (1)
Agilent Technologies	0.63 %	12.00 %	10.00 %	11.97 %	11.32 %	0.67 %	11.99 %
Abbott Labs.	1.97	7.00	5.10	8.30	6.80	2.04	8.84
Analog Devices	1.94	11.50	12.30	14.87	12.89	2.07	14.96
Assurant Inc.	2.12	15.50	12.70	17.40	15.20	2.28	17.48
Smith (A.O.)	2.14	11.50	9.00	8.00	9.50	2.24	11.74
Air Products & Chem.	2.28	11.00	12.20	10.65	11.28	2.41	13.69
Ball Corp.	1.54	21.50	5.00	4.51	10.34	1.62	11.96
Brown-Forman 'B'	1.21	14.50	NA	8.62	11.56	1.28	12.84
Bristol-Myers Squibb	3.02	NA	5.60	4.14	4.87	3.09	7.96
Broadridge Fin'l	2.05	9.50	NA	11.80	10.65	2.16	12.81
Brady Corp.	2.00	12.50	7.00	7.00	8.83	2.09	10.92
CACI Int'l	-	7.00	6.70	2.40	5.37	-	NA
Chemed Corp.	0.31	7.00	6.90	6.95	6.95	0.32	7.27
Cooper Cos.	0.02	12.00	11.00	10.00	11.00	0.02	11.02
CSW Industrials	0.57	11.50	NA	12.00	11.75	0.60	12.35
Quest Diagnostics	1.83	4.00	NA	(15.60)	4.00	1.87	5.87
Dolby Labs.	1.57	9.50	16.00	16.00	13.83	1.68	15.51
Lauder (Estee)	1.18	14.00	9.60	5.03	9.54	1.24	10.78
Exponent, Inc.	0.98	10.50	NA	15.00	12.75	1.04	13.79
FactSet Research	0.84	10.50	10.00	11.90	10.80	0.89	11.69
Gentex Corp.	1.79	10.00	16.60	15.80	14.13	1.92	16.05
Ingredion Inc.	3.06	8.00	NA	9.90	8.95	3.20	12.15
Hunt (J.B.)	0.91	11.00	15.00	14.98	13.66	0.97	14.63
J&J Snack Foods	1.88	9.00	NA	73.10	9.00	1.96	10.96
Henry (Jack) & Assoc	1.06	8.00	9.00	9.00	8.67	1.11	9.78
L3Harris Technologie	1.98	17.50	2.70	41.80	10.10	2.08	12.18
McCormick & Co.	1.93	5.00	5.30	5.10	5.13	1.98	7.11
Altria Group	8.27	5.50	4.00	4.16	4.55	8.46	13.01
MSA Safety	1.40	7.00	NA	18.00	12.50	1.49	13.99
MSCI Inc.	1.07	14.50	NA	12.53	13.52	1.14	14.66
Motorola Solutions	1.40	10.50	9.00	11.18	10.23	1.47	11.70
Mettler-Toledo Int'l	-	13.50	12.20	12.20	12.63	-	NA
Northrop Grumman	1.32	6.50	3.30	3.00	4.27	1.35	5.62
Old Dominion Freight	0.42	10.50	14.10	14.54	13.05	0.45	13.50
Packaging Corp.	3.98	11.00	5.00	(5.16)	8.00	4.14	12.14
Post Holdings	-	5.00	NA	32.40	5.00	-	NA
RLI Corp.	0.83	12.00	NA	9.80	10.90	0.88	11.78
Rollins, Inc.	1.33	10.50	NA	8.20	9.35	1.39	10.74
Service Corp. Int'l	1.61	2.00	12.00	12.00	8.67	1.68	10.35
Sherwin-Williams	1.03	11.50	12.80	11.46	11.92	1.09	13.01
Selective Ins. Group	1.31	9.50	6.60	13.40	9.83	1.37	11.20
Sirius XM Holdings	1.57	32.50	7.00	3.54	5.27	1.61	6.88
Sensient Techn.	2.29	2.50	NA	3.80	3.15	2.33	5.48
Thermo Fisher Sci.	0.23	10.50	12.50	3.51	8.84	0.24	9.08
Texas Instruments	2.97	7.50	9.30	10.00	8.93	3.10	12.03
U-Haul Holding	-	11.50	NA	15.00	13.25	-	NA
UniFirst Corp.	0.68	10.50	NA	10.00	10.25	0.71	10.96
VeriSign Inc.	-	11.00	NA	8.00	9.50	-	NA
Waters Corp.	-	6.00	7.20	8.34	7.18	-	NA
Watsco, Inc.	3.35	11.50	NA	15.00	13.25	3.57	16.82
						Mean	11.57 %
						Median	11.87 %
						Average of Mean and Median	11.72 %

NA= Not Available

(1) The application of the DCF model to the domestic, non-price regluated comparable risk companies is identical to the application of the DCF to the utility proxy group. The dividend yield is derived by using the 60 day average price and the spot indicated dividend as of December 30, 2022. The dividend yield is then adjusted by 1/2 the average projected growth rate in EPS, which is calculated by averaging the 5-year projected growth in EPS provided by Value Line, www.zacks.com, and www.yahoo.com (excluding any negative growth rates) and then adding that growth rate to the adjusted dividend yield.

Source of Information:
Value Line Investment Survey
www.zacks.com Downloaded on 12/30/2022
www.yahoo.com Downloaded on 12/30/2022

Jersey Central Power & Light Company
Indicated Common Equity Cost Rate
Through Use of a Risk Premium Model
Using an Adjusted Total Market Approach

Line No.		Proxy Group of Fifty Non-Price Regulated Companies
1.	Prospective Yield on Baa2 Rated Corporate Bonds (1)	6.05 %
2.	Adjustment to Reflect Proxy Group Bond Rating (2)	(0.17)
3.	Adjusted Bond Yield Applicable to the Non-Price Regulated Proxy Group	5.88 %
4.	Equity Risk Premium (3)	7.52
5.	Risk Premium Derived Common Equity Cost Rate	13.40 %

Notes: (1) Average forecast of Baa2 corporate bonds based upon the consensus of nearly 50 economists reported in Blue Chip Financial Forecasts dated January 1, 2023 and December 2, 2022 (see pages 10 and 11 of Schedule DWD-3). The estimates are detailed below.

First Quarter 2023	6.10 %
Second Quarter 2023	6.30
Third Quarter 2023	6.20
Fourth Quarter 2023	6.10
First Quarter 2024	5.90
Second Quarter 2024	5.80
2024-2028	6.00
2029-2033	6.00
Average	6.05 %

(2) To reflect the Baa1 average rating of the Non-Price Regulated Proxy Group, the prosepctive yield on Baa2 corporate bonds must be adjusted downward by 1/3 of the spread between A2 and Baa2 corporate bond yields as shown below:

	A2 Corp. Bond Yield	Baa2 Corp. Bond Yield	Spread
Dec-2022	5.10 %	5.58 %	0.48 %
Nov-2022	5.58	6.07	0.49
Oct-2022	5.74	6.26	0.52
		Average yield spread	0.50 %
		1/3 of spread	0.17 %

(3) From page 5 of this Schedule.

Jersey Central Power & Light Company
Comparison of Long-Term Issuer Ratings for the
Proxy Group of Fifty Non-Price Regulated Companies of Comparable risk to the
Proxy Group of Thirteen Electric Utilities

Proxy Group of Fifty Non-Price Regulated Companies	Moody's Long-Term Issuer Rating December 2022	Numerical Weighting (1)	Standard & Poor's Long-Term Issuer Rating December 2022	Numerical Weighting (1)
Agilent Technologies	Baa2	9.0	BBB+	8.0
Abbott Labs.	A1	5.0	AA-	4.0
Analog Devices	A3	7.0	A-	7.0
Assurant Inc.	Baa2	9.0	BBB	9.0
Smith (A.O.)	NA	--	NA	--
Air Products & Chem.	A2	6.0	A	6.0
Ball Corp.	Ba1	11.0	BB+	11.0
Brown-Forman 'B'	A1	5.0	A-	7.0
Bristol-Myers Squibb	A2	6.0	A+	5.0
Broadridge Fin'l	Baa1	8.0	BBB+	8.0
Brady Corp.	NA	--	NA	--
CACI Int'l	NA	--	BB+	11.0
Chemed Corp.	WR	--	NR	--
Cooper Cos.	WR	--	NR	--
CSW Industrials	NA	--	NA	--
Quest Diagnostics	Baa2	9.0	BBB+	8.0
Dolby Labs.	NA	--	NA	--
Lauder (Estee)	A1	5.0	A+	5.0
Exponent, Inc.	NA	--	NA	--
FactSet Research	Baa3	10.0	NA	--
Gentex Corp.	NA	--	NA	--
Ingredion Inc.	Baa1	8.0	BBB	9.0
Hunt (J.B.)	Baa1	8.0	BBB+	8.0
J&J Snack Foods	NA	--	NA	--
Henry (Jack) & Assoc	NA	--	NA	--
L3Harris Technologie	Baa2	9.0	BBB	9.0
McCormick & Co.	Baa2	9.0	BBB	9.0
Altria Group	A3	7.0	BBB	9.0
MSA Safety	NA	--	NA	--
MSCI Inc.	Ba1	11.0	BB+	11.0
Motorola Solutions	Baa3	10.0	BBB-	10.0
Mettler-Toledo Int'l	WR	--	NR	--
Northrop Grumman	Baa1	8.0	BBB+	8.0
Old Dominion Freight	NA	--	NA	--
Packaging Corp.	Baa2	9.0	BBB	9.0
Post Holdings	B2	15.0	B+	14.0
RLI Corp.	Baa2	9.0	BBB	9.0
Rollins, Inc.	NA	--	NA	--
Service Corp. Int'l	Ba3	13.0	BB+	11.0
Sherwin-Williams	Baa2	9.0	BBB	9.0
Selective Ins. Group	Baa2	9.0	BBB	9.0
Sirius XM Holdings	NA	--	NA	--
Sensient Techn.	WR	--	NR	--
Thermo Fisher Sci.	A3	7.0	A-	7.0
Texas Instruments	Aa3	4.0	A+	5.0
U-Haul Holding	WR	--	NR	--
UniFirst Corp.	NA	--	NA	--
VeriSign Inc.	Baa3	10.0	BBB	9.0
Waters Corp.	NA	--	NA	--
Watsco, Inc.	NA	--	NA	--
Average	Baa1	8.4	BBB+	8.4

Notes:
(1) From page 6 of Schedule DWD-3.

Source of Information:
Bloomberg Professional Services

Jersey Central Power & Light Company
Derivation of Equity Risk Premium Based on the Total Market Approach
Using the Beta for
Proxy Group of Fifty Non-Price Regulated Companies of Comparable risk to the
Proxy Group of Thirteen Electric Utilities

Line No.	Equity Risk Premium Measure	Proxy Group of Fifty Non-Price Regulated Companies
1.	Kroll Equity Risk Premium (1)	6.13 %
2.	Regression on Kroll Risk Premium Data (2)	7.26
3.	Kroll Equity Risk Premium based on PRPM (3)	9.76
4.	Equity Risk Premium Based on Value Line Summary and Index (4)	11.53
5	Equity Risk Premium Based on Value Line S&P 500 Companies (5)	10.62
6.	Equity Risk Premium Based on Bloomberg S&P 500 Companies (6)	6.01
7.	Conclusion of Equity Risk Premium	8.55 %
8.	Adjusted Beta (7)	0.88
9.	Forecasted Equity Risk Premium	7.52 %

Notes:

(1) From note 1 of page 9 of Schedule DWD-3.
(2) From note 2 of page 9 of Schedule DWD-3.
(3) From note 3 of page 9 of Schedule DWD-3.
(4) From note 4 of page 9 of Schedule DWD-3.
(5) From note 5 of page 9 of Schedule DWD-3.
(6) From note 6 of page 9 of Schedule DWD-3.
(7) Average of mean and median beta from page 6 of this Schedule.

Sources of Information:

Stocks, Bonds, Bills, and Inflation - 2022 SBBI Yearbook, Kroll, Inc.
Value Line Summary and Index
Blue Chip Financial Forecasts, January 1, 2023 and December 2, 2022
Bloomberg Professional Services

Jersey Central Power & Light Company
Traditional CAPM and ECAPM Results for the Proxy Group of Non-Price-Regulated Companies Comparable in Total Risk to the
Proxy Group of Thirteen Electric Utilities

	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Proxy Group of Fifty Non-Price Regulated Companies	Value Line Adjusted Beta	Bloomberg Beta	Average Beta	Market Risk Premium (1)	Risk-Free Rate (2)	Traditional CAPM Cost Rate	ECAPM Cost Rate	Indicated Common Equity Cost Rate (3)
Agilent Technologies	0.85	0.77	0.81	9.75 %	3.91 %	11.81 %	12.27 %	12.04 %
Abbott Labs.	0.90	0.81	0.86	9.75	3.91	12.29	12.64	12.47
Analog Devices	1.00	0.87	0.94	9.75	3.91	13.07	13.22	13.15
Assurant Inc.	0.90	0.85	0.88	9.75	3.91	12.49	12.78	12.64
Smith (A.O.)	0.90	0.76	0.83	9.75	3.91	12.00	12.42	12.21
Air Products & Chem.	0.90	0.79	0.85	9.75	3.91	12.20	12.56	12.38
Ball Corp.	1.05	0.91	0.98	9.75	3.91	13.46	13.51	13.49
Brown-Forman 'B'	0.85	0.80	0.83	9.75	3.91	12.00	12.42	12.21
Bristol-Myers Squibb	0.80	0.76	0.78	9.75	3.91	11.51	12.05	11.78
Broadridge Fin'l	0.90	0.70	0.80	9.75	3.91	11.71	12.20	11.95
Brady Corp.	0.95	0.93	0.94	9.75	3.91	13.07	13.22	13.15
CACI Int'l	0.90	0.84	0.87	9.75	3.91	12.39	12.71	12.55
Chemed Corp.	0.80	0.70	0.75	9.75	3.91	11.22	11.83	11.53
Cooper Cos.	0.95	0.90	0.93	9.75	3.91	12.98	13.15	13.06
CSW Industrials	0.85	0.80	0.83	9.75	3.91	12.00	12.42	12.21
Quest Diagnostics	0.80	0.69	0.75	9.75	3.91	11.22	11.83	11.53
Dolby Labs.	0.95	0.88	0.92	9.75	3.91	12.88	13.07	12.98
Lauder (Estee)	1.05	0.92	0.99	9.75	3.91	13.56	13.59	13.57
Exponent, Inc.	0.90	0.80	0.85	9.75	3.91	12.20	12.56	12.38
FactSet Research	1.00	0.93	0.97	9.75	3.91	13.37	13.44	13.40
Gentex Corp.	0.95	0.90	0.93	9.75	3.91	12.98	13.15	13.06
Ingredion Inc.	0.90	0.85	0.88	9.75	3.91	12.49	12.78	12.64
Hunt (J.B.)	0.95	0.90	0.93	9.75	3.91	12.98	13.15	13.06
J&J Snack Foods	0.90	0.87	0.89	9.75	3.91	12.59	12.86	12.72
Henry (Jack) & Assoc	0.85	0.70	0.78	9.75	3.91	11.51	12.05	11.78
L3Harris Technologie	0.90	0.92	0.91	9.75	3.91	12.78	13.00	12.89
McCormick & Co.	0.75	0.66	0.71	9.75	3.91	10.83	11.54	11.19
Altria Group	0.90	0.88	0.89	9.75	3.91	12.59	12.86	12.72
MSA Safety	1.00	0.92	0.96	9.75	3.91	13.27	13.37	13.32
MSCI Inc.	1.05	0.85	0.95	9.75	3.91	13.17	13.29	13.23
Motorola Solutions	0.90	0.79	0.85	9.75	3.91	12.20	12.56	12.38
Mettler-Toledo Int'l	0.95	0.89	0.92	9.75	3.91	12.88	13.07	12.98
Northrop Grumman	0.80	0.74	0.77	9.75	3.91	11.42	11.98	11.70
Old Dominion Freight	0.95	0.85	0.90	9.75	3.91	12.68	12.93	12.81
Packaging Corp.	0.95	0.90	0.93	9.75	3.91	12.98	13.15	13.06
Post Holdings	NMF	0.86	0.86	9.75	3.91	12.29	12.64	12.47
RLI Corp.	0.80	0.66	0.73	9.75	3.91	11.03	11.69	11.36
Rollins, Inc.	0.85	0.72	0.79	9.75	3.91	11.61	12.12	11.87
Service Corp. Int'l	0.95	0.89	0.92	9.75	3.91	12.88	13.07	12.98
Sherwin-Williams	0.95	0.84	0.90	9.75	3.91	12.68	12.93	12.81
Selective Ins. Group	0.85	0.81	0.83	9.75	3.91	12.00	12.42	12.21
Sirius XM Holdings	0.90	0.86	0.88	9.75	3.91	12.49	12.78	12.64
Sensient Techn.	0.95	0.82	0.89	9.75	3.91	12.59	12.86	12.72
Thermo Fisher Sci.	0.85	0.70	0.78	9.75	3.91	11.51	12.05	11.78
Texas Instruments	0.90	0.75	0.83	9.75	3.91	12.00	12.42	12.21
U-Haul Holding	0.95	0.92	0.94	9.75	3.91	13.07	13.22	13.15
UniFirst Corp.	0.95	0.91	0.93	9.75	3.91	12.98	13.15	13.06
VeriSign Inc.	0.95	0.78	0.87	9.75	3.91	12.39	12.71	12.55
Waters Corp.	0.95	0.87	0.91	9.75	3.91	12.78	13.00	12.89
Watsco, Inc.	0.85	0.75	0.80	9.75	3.91	11.71	12.20	11.95
Mean			0.87			12.38 %	12.70 %	12.54 %
Median			0.88			12.49 %	12.78 %	12.64 %
Average of Mean and Median			0.88			12.44 %	12.74 %	12.59 %

NMF = Not Meaningful Figure

Notes:
(1) From Schedule DWD-4, note 1.
(2) From Schedule DWD-4, note 2.
(3) Average of CAPM and ECAPM cost rates.

Jersey Central Power & Light Company
Derivation of Investment Risk Adjustment Based upon
Kroll Associates' Size Premia for the Decile Portfolios of the NYSE/AMEX/NASDAQ

Line No.		[1] Market Capitalization on December 30, 2022 (1) (millions)		[2] Applicable Decile of the NYSE/AMEX/ NASDAQ (2)	[3] Applicable Size Premium (3)	[4] Spread from Applicable Size Premium (4)
1.	Jersey Central Power & Light Company	$ 3,037.449		6	1.18%	
2.	Proxy Group of Thirteen Electric Utilities	$ 22,798.483	7.5 x	2	0.43%	0.75%
			[A]	[B]	[C]	[D]

	Decile	Market Capitalization of Smallest Company (millions)	Market Capitalization of Largest Company (millions)	Size Premium (Return in Excess of CAPM)*
Largest	1	$ 36,160.584	$ 2,324,390.219	-0.22%
	2	16,759.390	36,099.221	0.43%
	3	8,216.356	16,738.364	0.55%
	4	5,019.883	8,212.638	0.54%
	5	3,281.009	5,003.747	0.89%
	6	2,170.315	3,276.553	1.18%
	7	1,306.402	2,164.524	1.34%
	8	629.118	1,306.038	1.21%
	9	290.002	627.803	2.10%
Smallest	10	10.588	289.007	4.80%

*From 2022 Kroll Cost of Capital Navigator

Notes:

(1) From page 2 of this Schedule.
(2) Gleaned from Columns [B] and [C] on the bottom of this page. The appropriate decile (Column [A]) corresponds to the market capitalization of the proxy group, which is found in Column [1].
(3) Corresponding risk premium to the decile is provided in Column [D] on the bottom of this page.
(4) Line No. 1 Column [3] – Line No. 2 Column [3]. For example, the 0.75% in Column [4], Line No. 2 is derived as follows 0.75% = 1.18% - 0.43%.

Jersey Central Power & Light Company
Market Capitalization of Jersey Central Power & Light Company and the
Proxy Group of Thirteen Electric Utilities

Company	Exchange	[1] Common Stock Shares Outstanding at Fiscal Year End 2021 (millions)	[2] Book Value per Share at Fiscal Year End 2020 (1)	[3] Total Common Equity at Fiscal Year End 2021 (millions)	[4] Closing Stock Market Price on December 30, 2022	[5] Market-to-Book Ratio on December 30, 2022 (2)	[6] Market Capitalization on December 30, 2022 (3) (millions)
Jersey Central Power & Light Company		NA	NA	$ 1,550.510 (4)	NA		
Based upon Proxy Group of Thirteen Electric Utilities						195.9 (5)	$ 3,031.184 (6)
Proxy Group of Thirteen Electric Utilities							
Alliant Energy Corporation	NASDAQ	250.475	$ 23.915	$ 5,990.000	$ 55.210	230.9 %	$ 13,828.699
Ameren Corporation	NYSE	257.700	37.641	9,700.000	88.920	236.2	22,914.684
American Electric Power Corporation	NASDAQ	504.212	44.492	22,433.200	94.950	213.4	47,874.931
Duke Energy Corporation	NYSE	769.000	61.553	47,334.000	102.990	167.3	79,199.310
Edison International	NASDAQ	380.378	36.572	13,911.000	63.620	174.0	24,199.658
Entergy Corporation	NYSE	202.653	57.425	11,637.284	112.500	195.9	22,798.483
Evergy, Inc.	NYSE	229.300	40.316	9,244.400	62.930	156.1	14,429.843
Eversource Energy	NYSE	344.403	42.392	14,599.844	83.840	197.8	28,874.764
IDACORP, Inc.	NYSE	50.516	52.823	2,668.436	107.850	204.2	5,448.202
NorthWestern Corporation	NYSE	57.606	40.616	2,339.713	59.340	146.1	3,418.355
OGE Energy Corporation	NASDAQ	200.500	20.231	4,056.300	39.550	195.5	7,929.775
Portland General Electric Company	NYSE	89.411	30.276	2,707.000	49.000	161.8	4,381.120
Xcel Energy Inc.	NYSE	544.025	28.697	15,612.000	70.110	244.3	38,141.612
Median		250.475	$ 40.316	$ 9,700.000	$ 70.110	195.9 %	$ 22,798.483

NA= Not Available

Notes: (1) Column 3 / Column 1.
(2) Column 4 / Column 2.
(3) Column 1 * Column 4.
(4) Requested rate base multiplied by the requested common equity ratio.
(5) The market-to-book ratio of Jersey Central Power & Light Company on December 30, 2022 is assumed to be equal to the market-to-book ratio of Proxy Group of Thirteen Electric Utilities on December 30, 2022 as appropriate.
(6) Column [3] multiplied by Column [5].

Source of Information: 2021 Annual Forms 10K
Bloomberg Financial Services

Jersey Central Power & Light Company
Derivation of the Flotation Cost Adjustment to the Cost of Common Equity

Equity Issuances since 2003

Date of Offering	Transaction (1)	[Column 1] Shares Issued (1)	[Column 2] Market Price per Share (1)	[Column 3] Average Offering Price per Share (1)	[Column 4] Market Pressure (2)	[Column 5] Issuance Expense	[Column 6] Net Proceeds per Share (3)	[Column 7] Gross Equity Issue before Costs (4)	[Column 8] Total Net Proceeds (5)	[Column 9] Total Flotation Costs (6)	[Column 10] Flotation Cost Percentage (7)
9/11/2003	Equity Offering	32,200,000	$ 31.1000	$ 30.0000	$ 1.10	$ 0.975	$ 29.0250	$ 1,001,420,000	$ 934,605,000	$ 66,815,000	6.67%
12/13/2021	Equity Offering	25,588,535	$ 40.1700	$ 39.0800	$ 1.09	$ 1.016	$ 38.0639	$ 999,999,948	$ 973,999,948	$ 53,891,503	2.60%
								$ 2,001,419,948	$ 1,908,604,948	$ 120,706,503	4.64%

Flotation Cost Adjustment

	[Column 11] Average Dividend Yield (8)	[Column 12] Average Projected EPS Growth Rate (8)	[Column 13] Adjusted Dividend Yield (8)	[Column 14] Average DCF Cost Rate Unadjusted for Flotation (9)	[Column 15] DCF Cost Rate Adjusted for Flotation (10)	[Column 16] Flotation Cost Adjustment (11)
Proxy Group of Thirteen Electric Utilities	3.75 %	5.39 %	3.85 %	9.24 %	9.43 %	0.19 %

Notes:
(1) From Company SEC filings
(2) Col. 2 - Col. 3
(3) Col. 2 - Col. 4 - Col. 5
(4) Col. 1 x Col. 2
(5) Col. 1 x Col. 6
(6) Col. 1 *(Col. 4 + Col. 5)
(7) (Col. 7 - Col. 8) / Col. 7
(8) From Schedule DWD-2
(9) Col. 12 + Col. 13
(10) (Col. 13 / (1 - Col. 10)) + Col. 12
(11) Col. 15 - Col. 14

Source of Information: Company SEC filings.

Exhibit JC-7
Schedule DWD-8
Page 1 of 1

scottmadden
MANAGEMENT CONSULTANTS

Resume & Testimony Listing of:
Dylan W. D'Ascendis, CRRA, CVA
Partner

Summary

Dylan is an experienced consultant and a Certified Rate of Return Analyst (CRRA) and Certified Valuation Analyst (CVA). Dylan joined ScottMadden in 2016 and has become a leading expert witness with respect to cost of capital and capital structure. He has served as a consultant for investor-owned and municipal utilities and authorities for 14 years. Dylan has testified as an expert witness on over 125 occasions regarding rate of return, cost of service, rate design, and valuation before more than 35 regulatory jurisdictions in the United States and Canada, an American Arbitration Association panel, and the Superior Court of Rhode Island. He also maintains the benchmark index against which the Hennessy Gas Utility Mutual Fund performance is measured. Dylan holds a B.A. in economic history from the University of Pennsylvania and an M.B.A. with concentrations in finance and international business from Rutgers University.

Areas of Specialization

- Regulation and Rates
- Rate of Return
- Valuation
- Mutual Fund Benchmarking
- Capital Market Risk
- Regulatory Strategy
- Cost of Service

Recent Expert Testimony Submission/Appearance

- Regulatory Commission of Alaska – Capital Structure
- Federal Energy Regulatory Commission – Rate of Return
- Public Utility Commission of Texas – Return on Equity
- Hawaii Public Utilities Commission – Cost of Service / Rate Design
- Pennsylvania Public Utility Commission - Valuation

Recent Assignments

- Provided expert testimony on the cost of capital for ratemaking purposes before numerous state utility regulatory agencies
- Sponsored valuation testimony for a large municipal water company in front of an American Arbitration Association Board to justify the reasonability of their lease payments to the City
- Co-authored a valuation report on behalf of a large investor-owned utility company in response to a new state regulation which allowed the appraised value of acquired assets into rate base

Recent Articles and Speeches

- Co-Author of: "Decoupling, Risk Impacts and the Cost of Capital", co-authored with Richard A. Michelfelder, Ph.D., Rutgers University and Pauline M. Ahern. The Electricity Journal, March, 2020
- Co-Author of: "Decoupling Impact and Public Utility Conservation Investment", co-authored with Richard A. Michelfelder, Ph.D., Rutgers University and Pauline M. Ahern. Energy Policy Journal, 130 (2019), 311-319
- "Establishing Alternative Proxy Groups", before the Society of Utility and Regulatory Financial Analysts: 51st Financial Forum, April 4, 2019, New Orleans, LA
- "Past is Prologue: Future Test Year", Presentation before the National Association of Water Companies 2017 Southeast Water Infrastructure Summit, May 2, 2017, Savannah, GA.
- Co-author of: "Comparative Evaluation of the Predictive Risk Premium Model™, the Discounted Cash Flow Model and the Capital Asset Pricing Model", co-authored with Richard A. Michelfelder, Ph.D., Rutgers University, Pauline M. Ahern, and Frank J. Hanley, The Electricity Journal, May, 2013
- "Decoupling: Impact on the Risk and Cost of Common Equity of Public Utility Stocks", before the Society of Utility and Regulatory Financial Analysts: 45th Financial Forum, April 17-18, 2013, Indianapolis, IN

Sponsor	Date	Case/Applicant	Docket No.	Subject
Regulatory Commission of Alaska				
ENSTAR Natural Gas Company	08/22	ENSTAR Natural Gas Company	Docket No. TA334-4	Rate of Return
Cook Inlet Natural Gas Storage Alaska, LLC	07/21	Cook Inlet Natural Gas Storage Alaska, LLC	Docket No. TA45-733	Capital Structure
Alaska Power Company	09/20	Alaska Power Company; Goat Lake Hydro, Inc.; BBL Hydro, Inc.	Tariff Nos. TA886-2; TA6-521; TA4-573	Capital Structure
Alaska Power Company	07/16	Alaska Power Company	Docket No. TA857-2	Rate of Return
Alberta Utilities Commission				
AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	01/20	AltaLink, L.P., and EPCOR Distribution & Transmission, Inc.	2021 Generic Cost of Capital, Proceeding ID. 24110	Rate of Return
Arizona Corporation Commission				
Arizona Water Company	12/22	Arizona Water Company – Eastern Group	Docket No. W-01445A-22-0286	Rate of Return
EPCOR Water Arizona, Inc.	08/22	EPCOR Water Arizona, Inc.	Docket No. WS-01303A-22-0236	Rate of Return
EPCOR Water Arizona, Inc.	06/20	EPCOR Water Arizona, Inc.	Docket No. WS-01303A-20-0177	Rate of Return
Arizona Water Company	12/19	Arizona Water Company – Western Group	Docket No. W-01445A-19-0278	Rate of Return
Arizona Water Company	08/18	Arizona Water Company – Northern Group	Docket No. W-01445A-18-0164	Rate of Return
Arkansas Public Service Commission				
Southwestern Electric Power Co.	07/21	Southwestern Electric Power Co.	Docket No. 21-070-U	Return on Equity
CenterPoint Energy Resources Corp.	05/21	CenterPoint Arkansas Gas	Docket No. 21-004-U	Return on Equity
Colorado Public Utilities Commission				
Atmos Energy Corporation	08/22	Atmos Energy Corporation	Docket No. 22AL-0348G	Rate of Return
Summit Utilities, Inc.	04/18	Colorado Natural Gas Company	Docket No. 18AL-0305G	Rate of Return
Atmos Energy Corporation	06/17	Atmos Energy Corporation	Docket No. 17AL-0429G	Rate of Return
Delaware Public Service Commission				
Delmarva Power & Light Co.	01/22	Delmarva Power & Light Co.	Docket No. 22-002 (Gas)	Return on Equity
Delmarva Power & Light Co.	11/20	Delmarva Power & Light Co.	Docket No. 20-0149 (Electric)	Return on Equity
Delmarva Power & Light Co.	10/20	Delmarva Power & Light Co.	Docket No. 20-0150 (Gas)	Return on Equity
Tidewater Utilities, Inc.	11/13	Tidewater Utilities, Inc.	Docket No. 13-466	Capital Structure
Public Service Commission of the District of Columbia				
Washington Gas Light Company	04/22	Washington Gas Light Company	Formal Case No. 1169	Rate of Return
Washington Gas Light Company	09/20	Washington Gas Light Company	Formal Case No. 1162	Rate of Return
Federal Energy Regulatory Commission				
LS Power Grid California, LLC	10/20	LS Power Grid California, LLC	Docket No. ER21-195-000	Rate of Return
Florida Public Service Commission				
Tampa Electric Company	04/21	Tampa Electric Company	Docket No. 20210034-EI	Return on Equity
Peoples Gas System	09/20	Peoples Gas System	Docket No. 20200051-GU	Rate of Return
Utilities, Inc. of Florida	06/20	Utilities, Inc. of Florida	Docket No. 20200139-WS	Rate of Return
Hawaii Public Utilities Commission				
Launiupoko Irrigation Company, Inc.	12/20	Launiupoko Irrigation Company, Inc.	Docket No. 2020-0217 / Transferred to 2020-0089	Capital Structure

Resume and Testimony Listing of:
Dylan W. D'Ascendis, CRRA, CVA
Partner

Sponsor	Date	Case/Applicant	Docket No.	Subject
Lanai Water Company, Inc.	12/19	Lanai Water Company, Inc.	Docket No. 2019-0386	Cost of Service / Rate Design
Manele Water Resources, LLC	08/19	Manele Water Resources, LLC	Docket No. 2019-0311	Cost of Service / Rate Design
Kaupulehu Water Company	02/18	Kaupulehu Water Company	Docket No. 2016-0363	Rate of Return
Aqua Engineers, LLC	05/17	Puhi Sewer & Water Company	Docket No. 2017-0118	Cost of Service / Rate Design
Hawaii Resources, Inc.	09/16	Laie Water Company	Docket No. 2016-0229	Cost of Service / Rate Design
Illinois Commerce Commission				
Utility Services of Illinois, Inc.	02/21	Utility Services of Illinois, Inc.	Docket No. 21-0198	Rate of Return
Ameren Illinois Company d/b/a Ameren Illinois	07/20	Ameren Illinois Company d/b/a Ameren Illinois	Docket No. 20-0308	Return on Equity
Utility Services of Illinois, Inc.	11/17	Utility Services of Illinois, Inc.	Docket No. 17-1106	Cost of Service / Rate Design
Aqua Illinois, Inc.	04/17	Aqua Illinois, Inc.	Docket No. 17-0259	Rate of Return
Utility Services of Illinois, Inc.	04/15	Utility Services of Illinois, Inc.	Docket No. 14-0741	Rate of Return
Indiana Utility Regulatory Commission				
Aqua Indiana, Inc.	03/16	Aqua Indiana, Inc. Aboite Wastewater Division	Docket No. 44752	Rate of Return
Twin Lakes, Utilities, Inc.	08/13	Twin Lakes, Utilities, Inc.	Docket No. 44388	Rate of Return
Kansas Corporation Commission				
Atmos Energy Corporation	07/19	Atmos Energy Corporation	19-ATMG-525-RTS	Rate of Return
Kentucky Public Service Commission				
Water Service Corporation of KY	06/22	Water Service Corporation of KY	2022-00147	Rate of Return
Atmos Energy Corporation	07/21	Atmos Energy Corporation	2021-00304	PRP Rider Rate
Atmos Energy Corporation	06/21	Atmos Energy Corporation	2021-00214	Rate of Return
Duke Energy Kentucky, Inc.	06/21	Duke Energy Kentucky, Inc.	2021-00190	Return on Equity
Bluegrass Water Utility Operating Company	10/20	Bluegrass Water Utility Operating Company	2020-00290	Return on Equity
Louisiana Public Service Commission				
Utilities, Inc. of Louisiana	05/21	Utilities, Inc. of Louisiana	Docket No. U-36003	Rate of Return
Southwestern Electric Power Company	12/20	Southwestern Electric Power Company	Docket No. U-35441	Return on Equity
Atmos Energy	04/20	Atmos Energy	Docket No. U-35535	Rate of Return
Louisiana Water Service, Inc.	06/13	Louisiana Water Service, Inc.	Docket No. U-32848	Rate of Return
Maine Public Utilities Commission				
Summit Natural Gas of Maine, Inc.	03/22	Summit Natural Gas of Maine, Inc.	Docket No. 2022-00025	Rate of Return
The Maine Water Company	09/21	The Maine Water Company	Docket No. 2021-00053	Rate of Return
Maryland Public Service Commission				
Washington Gas Light Company	08/20	Washington Gas Light Company	Case No. 9651	Rate of Return
FirstEnergy, Inc.	08/18	Potomac Edison Company	Case No. 9490	Rate of Return
Massachusetts Department of Public Utilities				
Unitil Corporation	12/19	Fitchburg Gas & Electric Co. (Elec.)	D.P.U. 19-130	Rate of Return
Unitil Corporation	12/19	Fitchburg Gas & Electric Co. (Gas)	D.P.U. 19-131	Rate of Return
Liberty Utilities	07/15	Liberty Utilities d/b/a New England Natural Gas Company	Docket No. 15-75	Rate of Return
Minnesota Public Utilities Commission				

Sponsor	Date	Case/Applicant	Docket No.	Subject
Northern States Power Company	11/01	Northern States Power Company	Docket No. G002/GR-21-678	Return on Equity
Northern States Power Company	10/21	Northern States Power Company	Docket No. E002/GR-21-630	Return on Equity
Northern States Power Company	11/20	Northern States Power Company	Docket No. E002/GR-20-723	Return on Equity
Mississippi Public Service Commission				
Great River Utility Operating Co.	07/22	Great River Utility Operating Co.	Docket No. 2022-UN-86	Rate of Return
Atmos Energy	03/19	Atmos Energy	Docket No. 2015-UN-049	Capital Structure
Atmos Energy	07/18	Atmos Energy	Docket No. 2015-UN-049	Capital Structure
Missouri Public Service Commission				
Spire Missouri, Inc.	12/20	Spire Missouri, Inc.	Case No. GR-2021-0108	Return on Equity
Indian Hills Utility Operating Company, Inc.	10/17	Indian Hills Utility Operating Company, Inc.	Case No. SR-2017-0259	Rate of Return
Raccoon Creek Utility Operating Company, Inc.	09/16	Raccoon Creek Utility Operating Company, Inc.	Case No. SR-2016-0202	Rate of Return
Public Utilities Commission of Nevada				
Southwest Gas Corporation	09/21	Southwest Gas Corporation	Docket No. 21-09001	Return on Equity
Southwest Gas Corporation	08/20	Southwest Gas Corporation	Docket No. 20-02023	Return on Equity
New Hampshire Public Utilities Commission				
Aquarion Water Company of New Hampshire, Inc.	12/20	Aquarion Water Company of New Hampshire, Inc.	Docket No. DW 20-184	Rate of Return
New Jersey Board of Public Utilities				
Middlesex Water Company	05/21	Middlesex Water Company	Docket No. WR21050813	Rate of Return
Atlantic City Electric Company	12/20	Atlantic City Electric Company	Docket No. ER20120746	Return on Equity
FirstEnergy	02/20	Jersey Central Power & Light Co.	Docket No. ER20020146	Rate of Return
Aqua New Jersey, Inc.	12/18	Aqua New Jersey, Inc.	Docket No. WR18121351	Rate of Return
Middlesex Water Company	10/17	Middlesex Water Company	Docket No. WR17101049	Rate of Return
Middlesex Water Company	03/15	Middlesex Water Company	Docket No. WR15030391	Rate of Return
The Atlantic City Sewerage Company	10/14	The Atlantic City Sewerage Company	Docket No. WR14101263	Cost of Service / Rate Design
Middlesex Water Company	11/13	Middlesex Water Company	Docket No. WR1311059	Capital Structure
New Mexico Public Regulation Commission				
Southwestern Public Service Co.	01/21	Southwestern Public Service Co.	Case No. 20-00238-UT	Return on Equity
North Carolina Utilities Commission				
Carolina Water Service, Inc.	07/22	Carolina Water Service, Inc.	Docket No. W-354 Sub 400	Rate of Return
Aqua North Carolina, Inc.	06/22	Aqua North Carolina, Inc.	Docket No. W-218 Sub 573	Rate of Return
Carolina Water Service, Inc.	07/21	Carolina Water Service, Inc.	Docket No. W-354 Sub 384	Rate of Return
Piedmont Natural Gas Co., Inc.	03/21	Piedmont Natural Gas Co., Inc.	Docket No. G-9, Sub 781	Return on Equity
Duke Energy Carolinas, LLC	07/20	Duke Energy Carolinas, LLC	Docket No. E-7, Sub 1214	Return on Equity
Duke Energy Progress, LLC	07/20	Duke Energy Progress, LLC	Docket No. E-2, Sub 1219	Return on Equity
Aqua North Carolina, Inc.	12/19	Aqua North Carolina, Inc.	Docket No. W-218 Sub 526	Rate of Return
Carolina Water Service, Inc.	06/19	Carolina Water Service, Inc.	Docket No. W-354 Sub 364	Rate of Return
Carolina Water Service, Inc.	09/18	Carolina Water Service, Inc.	Docket No. W-354 Sub 360	Rate of Return
Aqua North Carolina, Inc.	07/18	Aqua North Carolina, Inc.	Docket No. W-218 Sub 497	Rate of Return
North Dakota Public Service Commission				
Northern States Power Company	09/21	Northern States Power Company	Case No. PU-21-381	Rate of Return
Northern States Power Company	11/20	Northern States Power Company	Case No. PU-20-441	Rate of Return
Public Utilities Commission of Ohio				
Duke Energy Ohio, Inc.	10/21	Duke Energy Ohio, Inc.	Case No. 21-887-EL-AIR	Return on Equity

Resume and Testimony Listing of:
Dylan W. D'Ascendis, CRRA, CVA
Partner

Sponsor	Date	Case/Applicant	Docket No.	Subject
Aqua Ohio, Inc.	07/21	Aqua Ohio, Inc.	Case No. 21-0595-WW-AIR	Rate of Return
Aqua Ohio, Inc.	05/16	Aqua Ohio, Inc.	Case No. 16-0907-WW-AIR	Rate of Return
Pennsylvania Public Utility Commission				
Borough of Ambler	06/22	Borough of Ambler – Bureau of Water	Docket No. R-2022-3031704	Rate of Return
Citizens' Electric Company of Lewisburg	05/22	C&T Enterprises	Docket No. R-2022-3032369	Rate of Return
Valley Energy Company	05/22	C&T Enterprises	Docket No. R-2022-3032300	Rate of Return
Community Utilities of Pennsylvania, Inc.	04/21	Community Utilities of Pennsylvania, Inc.	Docket No. R-2021-3025207	Rate of Return
Vicinity Energy Philadelphia, Inc.	04/21	Vicinity Energy Philadelphia, Inc.	Docket No. R-2021-3024060	Rate of Return
Delaware County Regional Water Control Authority	02/20	Delaware County Regional Water Control Authority	Docket No. A-2019-3015173	Valuation
Valley Energy, Inc.	07/19	C&T Enterprises	Docket No. R-2019-3008209	Rate of Return
Wellsboro Electric Company	07/19	C&T Enterprises	Docket No. R-2019-3008208	Rate of Return
Citizens' Electric Company of Lewisburg	07/19	C&T Enterprises	Docket No. R-2019-3008212	Rate of Return
Steelton Borough Authority	01/19	Steelton Borough Authority	Docket No. A-2019-3006880	Valuation
Mahoning Township, PA	08/18	Mahoning Township, PA	Docket No. A-2018-3003519	Valuation
SUEZ Water Pennsylvania Inc.	04/18	SUEZ Water Pennsylvania Inc.	Docket No. R-2018-000834	Rate of Return
Columbia Water Company	09/17	Columbia Water Company	Docket No. R-2017-2598203	Rate of Return
Veolia Energy Philadelphia, Inc.	06/17	Veolia Energy Philadelphia, Inc.	Docket No. R-2017-2593142	Rate of Return
Emporium Water Company	07/14	Emporium Water Company	Docket No. R-2014-2402324	Rate of Return
Columbia Water Company	07/13	Columbia Water Company	Docket No. R-2013-2360798	Rate of Return
Penn Estates Utilities, Inc.	12/11	Penn Estates, Utilities, Inc.	Docket No. R-2011-2255159	Capital Structure / Long-Term Debt Cost Rate
South Carolina Public Service Commission				
Blue Granite Water Co.	12/19	Blue Granite Water Company	Docket No. 2019-292-WS	Rate of Return
Carolina Water Service, Inc.	02/18	Carolina Water Service, Inc.	Docket No. 2017-292-WS	Rate of Return
Carolina Water Service, Inc.	06/15	Carolina Water Service, Inc.	Docket No. 2015-199-WS	Rate of Return
Carolina Water Service, Inc.	11/13	Carolina Water Service, Inc.	Docket No. 2013-275-WS	Rate of Return
United Utility Companies, Inc.	09/13	United Utility Companies, Inc.	Docket No. 2013-199-WS	Rate of Return
Utility Services of South Carolina, Inc.	09/13	Utility Services of South Carolina, Inc.	Docket No. 2013-201-WS	Rate of Return
Tega Cay Water Services, Inc.	11/12	Tega Cay Water Services, Inc.	Docket No. 2012-177-WS	Capital Structure
South Dakota Public Service Commission				
Northern States Power Company	06/22	Northern States Power Company	Docket No. EL22-017	Rate of Return
Tennessee Public Utility Commission				
Piedmont Natural Gas Company	07/20	Piedmont Natural Gas Company	Docket No. 20-00086	Return on Equity
Public Utility Commission of Texas				
Oncor Electric Delivery Co. LLC	05/22	Oncor Electric Delivery Co. LLC	Docket No. 53601	Return on Equity
Southwestern Public Service Co.	02/21	Southwestern Public Service Co.	Docket No. 51802	Return on Equity
Southwestern Electric Power Co.	10/20	Southwestern Electric Power Co.	Docket No. 51415	Rate of Return
Virginia State Corporation Commission				
Washington Gas Light Company	06/22	Washington Gas Light Company	PUR-2022-00054	Return on Equity
Virginia Natural Gas, Inc.	04/21	Virginia Natural Gas, Inc.	PUR-2020-00095	Return on Equity

Resume and Testimony Listing of:
Dylan W. D'Ascendis, CRRA, CVA
Partner

Sponsor	Date	Case/Applicant	Docket No.	Subject
Massanutten Public Service Corporation	12/20	Massanutten Public Service Corporation	PUE-2020-00039	Return on Equity
Aqua Virginia, Inc.	07/20	Aqua Virginia, Inc.	PUR-2020-00106	Rate of Return
WGL Holdings, Inc.	07/18	Washington Gas Light Company	PUR-2018-00080	Rate of Return
Atmos Energy Corporation	05/18	Atmos Energy Corporation	PUR-2018-00014	Rate of Return
Aqua Virginia, Inc.	07/17	Aqua Virginia, Inc.	PUR-2017-00082	Rate of Return
Massanutten Public Service Corp.	08/14	Massanutten Public Service Corp.	PUE-2014-00035	Rate of Return / Rate Design
Public Service Commission of West Virginia				
Monongahela Power Company and The Potomac Edison Company	12/21	Monongahela Power Company and The Potomac Edison Company	Case No. 21-0857-E-CN (ELG)	Return on Equity
Monongahela Power Company and The Potomac Edison Company	11/21	Monongahela Power Company and The Potomac Edison Company	Case No. 21-0813-E-P (Solar)	Return on Equity

EXHIBIT JC-8

BEFORE THE
NEW JERSEY BOARD OF PUBLIC UTILITIES

In the Matter of the Verified Petition of Jersey Central Power & Light Company for Review and Approval of Increases in and Other Adjustments to Its Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith

Direct Testimony

of

Timothy S. Lyons

on

Class Cost of Service Study

TABLE OF CONTENTS

EXHIBIT JC-8

DIRECT TESTIMONY OF TIMOTHY S. LYONS ON BEHALF OF JERSEY CENTRAL POWER & LIGHT COMPANY

I. Introduction and Qualifications

Q. Please state your name and business address.

A. My name is Timothy S. Lyons. My business address is 3 Speen Street, Suite 150, Framingham, Massachusetts 01701.

Q. Please describe your current position.

A. I am a Partner at ScottMadden, Inc. ("ScottMadden").

Q. Please describe your work experience and qualifications.

A. I have more than 30 years of experience in the energy industry. I started my career in 1985 at Boston Gas Company, eventually becoming Director of Rates and Revenue Analysis. In 1993, I moved to Providence Gas Company, eventually becoming Vice President of Marketing and Regulatory Affairs. Starting in 2001, I held several management consulting positions in the energy industry, first at KEMA and then at Quantec, LLC. In 2005, I became Vice President of Sales and Marketing at Vermont Gas Systems, Inc. before joining Sussex Economic Advisors, LLC ("Sussex") in 2013. Sussex was acquired by ScottMadden in 2016.

Q. Please describe your educational background.

A. I hold a bachelor's degree from St. Anselm College, a master's degree in Economics from The Pennsylvania State University, and a master's degree in Business Administration from Babson College.

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

A. Yes. A summary of my testimony experience is included as Appendix A.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to sponsor the results of the Class Cost of Service Study ("COSS") conducted on behalf of Jersey Central Power & Light Company ("JCP&L" or the "Company"), a subsidiary of FirstEnergy Corp. ("FirstEnergy"). The COSS is submitted as part of the Company's February 2023 base rate filing with the Board. The COSS was used to guide the Company's proposed rate design.

The testimony describes development of two COSS studies.

- The first COSS ("Complied COSS") is based on methodologies approved by the Board in Docket No. ER12111052, the Company's most recent fully-litigated rate case in 2012 ("2012 Base Rate Filing" or "Docket No. ER12111052").
- The second COSS ("Alternative COSS") is based on methodologies that address concerns with certain cost allocation methodologies in the Complied COSS, as discussed below.

Q. Are you sponsoring schedules in connection with your testimony?

A. Yes. I am sponsoring the following schedules that were prepared by me or under my direction:

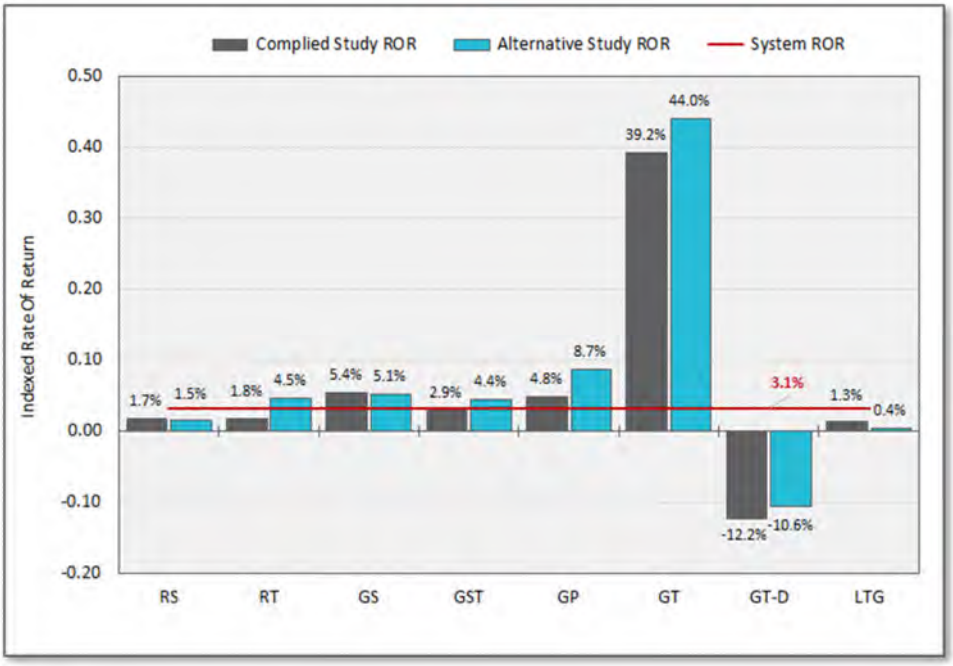
- Schedule TSL-1 – Complied COSS Results
- Schedule TSL-2 – Alternative COSS Results

II. Overview of Testimony

Q. Please summarize your Direct Testimony.

A. The results of the Company's Complied and Alternative COSS show differences in class rates of return ("ROR") for each rate class as compared to the system or overall ROR, as shown in Figure 1 (below).

Figure 1: COSS Results (Complied and Alternative COSS)



The Figure compares class RORs to the system or overall ROR based on current rates.

The Figure shows that Residential ("RS"), Residential Time of Day ("RT"), General Service Time of Day ("GST"), General Service Transmission Provision D ("GT-D"), and Lighting ("LTG") rate classes produce RORs below the system ROR in the Complied COSS study. The RS, GT-D, and LTG rate classes also produce RORs below

the system ROR in the Alternative COSS, while the RT and GST rate classes produce RORs above the system ROR in the Alternative COSS.

The Figure also shows the Company's General Service Secondary ("GS"), General Service Primary ("GP"), and General Service Transmission ("GT") rate classes produce RORs above the system ROR in both the Complied and Alternative COSS.

In general, individual class RORs were used to help guide the proposed rate design, as explained in the testimony of Company witness Yongmei Peng.

Q. Please describe the Company's service area and rate schedules.

A. JCP&L is a regulated utility providing electric service in New Jersey. The Company provides electric service to residential, commercial, and industrial ("C&I"), and lighting customers.

Customers are presently served under one of 12 rate classes based on type of service and load characteristics, as shown in Figure 2 (below). The Figure shows there are three residential classes, four C&I classes, and five lighting classes. For developing the COSS, the Residential Geothermal & Heat Pump Service ("RGT") is combined with the RT class, GT-D rate class is analyzed separately from GT rate class, and all five lighting classes are combined into one LTG rate class.

Figure 2: Current Rate Structure

Rate Class	Description
Residential General Service	Available for: (a) Individual Residential Structures; (b) separately metered residences in Multiple Residential Structures; (c) incidental use for non-residential purposes when included along with the residence; and/or (d) Auxiliary Residential Purposes whether metered separately from the residence or not.
Residential Time-of-Day	Available for: (a) Individual Residential Structures; (b) separately metered residences in Multiple Residential Structures; (c) incidental use for non-residential purposes when included along with the residence; and/or (d) Auxiliary Residential Purposes whether metered separately from the residence or not. For COSS purposes, includes Residential Geothermal & Heat Pump Service (RGT).
General Service Secondary	Available for general service purposes at secondary voltages not included under Service Classifications RS, RT, RGT or GST. Single or three-phase service at secondary voltages.
General Service Secondary Time-of-Day	Available for general Service purposes for C&I customers establishing demands in excess of 750 KW in two consecutive months during the current 24-month period. Customers which were served under this Service Classification as part of its previous experimental implementation may continue such Service until voluntarily transferring to Service Classification GS. Single or three-phase service at secondary voltages.
General Service Primary	Available for general service purposes for C&I customers. Single or three-phase service at primary voltages.
General Service Transmission	Available for general service purposes for C&I customers. Three-phase service at transmission voltages. Excludes special provision (d) Closing of GTX Service customers.
General Service Transmission Provision D	Special provision D of Schedule GT. Available for former Schedule GTX customers.
Lighting	Includes Outdoor Lighting Service (OL), Sodium Vapor Street Lighting Service (SVL), Mercury Vapor Street Lighting (MVL), Incandescent Street Lighting (ISL), LED Street Lighting Service (LED).

Q. Please provide a breakdown of the Company's customers.

A. Figure 3 (below) provides a breakdown of the Company's customers and kWh sales by rate class. The test year represents the period July 1, 2022 through June 30, 2023, representing 6-months of historical data (July 1, 2022 through December 31, 2022) and 6-months of forecast data (January 1, 2023 through June 30, 2023). The sales in Figure 3 were based on normal weather.

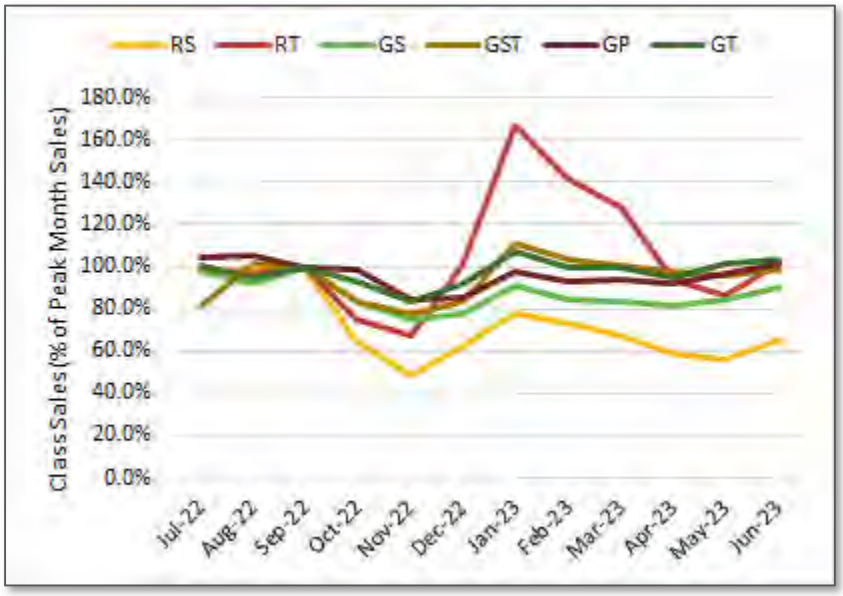
Figure 3: July 1, 2022 through June 30, 2023 Test Year Customers and Sales

Rate Class	Number of Customers	% of Customers	Normalized Sales (kWh)	% of Sales	kWh Sales per Customer
RS	1,005,454	87.2%	9,422,567	46.7%	9,371
RT	14,230	1.2%	195,504	1.0%	13,739
GS	129,795	11.3%	6,496,218	32.2%	50,050
GST	188	0.0%	441,097	2.2%	2,349,019
GP	599	0.1%	1,594,495	7.9%	2,661,443
GT	172	0.0%	1,708,916	8.5%	9,914,079
[redacted]					
Lighting	2,857	0.2%	112,498	0.6%	39,383
Total	1,153,297		20,178,644		17,496

The Figure shows Residential rate classes (RS and RT) represent a majority (88.4 percent) of the Company's customers. The Figure also shows variations in annual use per customer among the rate classes. RS customers, for example, use on average 9,371 kWh per year, while GP customers use on average 2,661,443 kWh per year.

Figure 4 (below) shows monthly kWh sales by rate class as a percentage of class peak month (September) sales. The Figure shows sales vary seasonally for certain rate classes.

Figure 4: Monthly kWh Sales as % of System Peak Month (September)



The RS rate class, for example, shows a seasonal load pattern, with monthly sales increasing during the winter and summer months, reflecting heating and cooling use, respectively. The GS rate class, by comparison, shows a consistent load pattern throughout the year, with a slight increase in the summer months. Demand differences, as discussed below, have implications on the allocation of costs in the COSS studies.

III. Class Cost of Service Study

Q. What is the purpose of a COSS?

A. The purpose of a COSS is to allocate a utility's overall cost of service to each rate class in a manner that reflects its underlying cost of service. The approach is well established in industry literature.[1]

Q. What was the approach used to develop the COSS for this case?

[1] See Principles of Public Utility Rates by James C. Bonbright.

A. The approach used to develop the COSS for this case was based on three steps. First, costs were functionalized or assigned into functional categories. Next, functionalized costs were classified into one of three cost drivers, based on whether the costs are related to: (1) serving peak demands, (2) serving energy demands, or (3) meeting customer service requirements. Finally, classified costs were allocated to each rate class based on methods that best reflect how the costs were incurred.

The three steps were performed using two types of assignments: direct assignment and indirect assignment. Direct assignments utilized the Company's financial data and certain assignments of plant investments and expenses to certain functions, classifications, and rate classes. Indirect assignments utilized composite allocators based on direct and indirect assignments developed during the functionalization, classification, and allocation process. The three steps were utilized to prepare the two COSS studies.

- The first or Complied COSS was based on methodologies approved by the Board in Docket No. ER12111052, the Company's 2012 Base Rate Filing.
- The second or Alternative COSS was based on certain refinements to the Complied COSS. The refinements address concerns with certain methodologies in the Complied COSS.

Q. What is functionalization?

A. Functionalization is the process of assigning rate base and expense items into operational components. The functionalization of costs in the COSS studies was based on the Company's accounting records, which are maintained in accordance with the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts ("USOA").

Q. What is classification?

A. Classification is the process of assigning rate base and expense items into categories that reflect cost-causation. There are three principle causes or drivers of costs related to the electric system:

- Customer-related – costs that vary with the number of customers, such as costs associated with connecting customers to the electric system and providing basic customer services, such as metering and billing;
- Demand-related – costs that vary with maximum customer demands at the time of the system peak, at the time of the rate class peak, or at the time of the individual customer peak; and
- Energy-related – costs that vary with production, transmission, and/or delivery of energy, such as fuel and purchased power expenses.

Q. What is allocation?

A. Allocation is the process of assigning rate base and expense items to each rate class based on allocators that best reflect how the costs were incurred. In other words, cost allocation should follow how costs were incurred.

Q. What types of allocators were used to develop the COSS studies?

A. There were three types of allocators used to develop the COSS studies:

1. Class determinants – class characteristics, such as number of customers, peak demands, kWh sales, and revenues by rate class;
2. Special studies – detailed analysis of specific plant or expense items, such as meters and services; and

3. Indirect – composite allocators based on how other costs were allocated.

Q. What was the approach used to develop the COSS for this case?

A. The Complied and Alternative COSS studies were based on a spreadsheet model developed by ScottMadden for this filing. Rate base and expense items in the COSS studies were assigned to each rate class based on the three-step process described above. The results of the Complied and Alternative COSS studies are shown in Figure 1 (above).

Q. What conclusions can be reached when a rate class ROR is lower or higher than the system or overall ROR?

A. If a rate class produces a ROR that is lower than the system ROR, then the revenues recovered from the rate class are less than its cost of service. Conversely, if a rate class produces a ROR that is higher than the system ROR, then the revenues recovered from the rate class are more than its cost of service. As discussed in the testimony of Company witness Yongmei Peng, the COSS results were used to establish revenue targets for each rate class, subject to bill continuity concerns, that move the Company's proposed rates in aggregate closer to the system ROR to achieve more fair and equitable rates across customer classes.

Q. What data was used to prepare the COSS?

A. The COSS was based on financial data for the period July 1, 2022 through June 30, 2023, with 6-months of historical data (July 1, 2022 through December 31, 2022) and 6-months of forecasted data (January 1, 2023 through June 30, 2023). The COSS includes the number of customers, sales, and revenues by rate class. Sales and revenues have been adjusted to reflect normal weather. The COSS also includes rate base items, including

intangible plant, distribution, and general plant-in-service as well as (a) additions to plant-in-service, including materials and supplies, cash working capital, and other regulatory assets, and (b) reductions to plant-in-service, including accumulated deferred income taxes ("ADIT"), customer deposits, customer advances, and other regulatory liabilities. The COSS also includes operations and maintenance ("O&M") expenses, including distribution, customer service, customer account, sales, and administrative and general expenses as well as taxes other than income, such as payroll and property taxes, and income taxes.

IV. Development of the Complied COSS

Q. Why did the Company prepare a "Complied" COSS study?

A. The Company prepared a Complied COSS study in compliance with the Board's directive in the Company's 2012 Base Rate Filing (Docket No. ER12111052). Specifically, the Commission stated:

> "…the Board ORDERS the Company to submit in its next base rate petition a cost of service study pursuant to the prescriptions detailed in Exhibit S-61, pages 1 through 8, attached hereto as Attachment B."[2]

Q. What was the approach to functionalize costs in the Complied COSS?

A. The Complied COSS includes only distribution costs consistent with the Company's revenue requirements.

[2] Docket No. ER12111052 (2012 Base Rate Filing), 'Order Adopting Initial Decision with Modifications and Clarifications' at 76.

Distribution costs include: (1) rate base and O&M expenses related to the distribution facilities, (2) customer-specific facilities, such as meters (370) and services (369), and (3) customer services, such as meter reading expenses (902) and customer records and collection expenses (903). Distribution costs were identified from the Company's accounting records, which are maintained in accordance with the FERC's USOA.

The Complied COSS further functionalized costs by primary and secondary distribution based on voltage levels to more accurately allocate distribution costs to each rate class. It was important to functionalize costs by primary and secondary distribution since some customers are served only from primary distribution facilities and thus should not be allocated costs related to the secondary distribution facilities. Costs were functionalized into primary and secondary distribution consistent with the Board's order in the Company's 2012 Base Rate Filing in the following manner:

- Primary Distribution – Fifty percent of costs related to Land and Land Rights (360), Structures and Improvements (361), Station Equipment (362), poles and towers (364), Overhead Conductors and Devices (365), and Underground Conductors and Devices (367) were assigned to primary distribution. Ninety percent of Underground Conductors and Devices (366) were assigned to primary distribution.
- Secondary Distribution – Fifty percent of costs related to Land and Land Rights (360), Structures and Improvements (361), Station Equipment (362), poles and towers (364), Overhead Conductors and Devices (365), and Underground Conductors and Devices (367) were assigned to secondary distribution. Ten

percent of Underground Conductors and Devices (366) were assigned to secondary distribution.

The remaining rate base and expense items were functionalized based on various methods.

Q. What was the approach to classify costs in the Complied COSS?

A. The Complied COSS generally classified costs based on the Average and Excess ("A&E") method, consistent with the Board's order in Docket No. ER12111052.

Q. What is the A&E method?

A. The A&E method is recognized by National Association of Regulatory Utility Commissioners ("NARUC") as a method to classify production or generation costs since production costs are driven by customer demand and energy requirements.[3]

Q. What costs in the Complied COSS were classified using the A&E method?

A. The Complied COSS classifies distribution costs using the A&E method.

Q. How were distribution costs classified and allocated using the A&E method?

A. Distribution costs were classified and allocated using the A&E method in two steps. The first step was to calculate average demand, which represents the energy portion of the Company's facilities. It represents each rate class's share of the average demand and is calculated as each class's share of total kWh sales. The average demand component is

[3] NARUC Electric Utility Cost Allocation Manual (January 1992) ("NARUC Manual") states (at p. 35): "Production plant costs can be classified in two ways between costs that are demand-related and those that are energy-related." In a later discussion, the NARUC Manual states the A&E method is a method to classify and allocate production plant (at pp. 49-52).

weighted by the system load factor representing that portion of a utility's capacity that would be needed if all customers used energy at a constant 100.0 percent load factor.

The second step was to calculate "excess" demand, which in the Complied COSS represents the peak demand portion of the Company's facilities. It represents each rate class's share of the peak demand. The class peak demand is based on coincident peak ("CP") demands. The "excess" demand component is weighted by 1 minus the system load factor – and then added to the average demand component to derive the A&E allocator.

Classification of costs using the A&E method was developed utilizing average demand (kWh) and CP demand data collected by the Company for each rate class utilizing billing and load research data. The CP demand represents class demand at the time of the system peak.

The Complied COSS has separate classifiers for the primary and secondary distribution systems, reflecting the average and excess demands on each system.

Q. Does the Company have concerns with the A&E method used in the Complied COSS?

A. Yes. The Complied COSS does not classify and allocate costs consistent with the A&E method described by NARUC. Specifically, NARUC describes "excess" demand as "the proportion of the difference between the sum of all classes' non-coincident peaks and the system average demand."[4]

The Complied COSS has two important differences compared to NARUC's description. First, "excess" demand in the Complied COSS is based on the sum of class peak demands, rather than the difference (or excess) between class peak and class average

[4] NARUC Electric Utility Cost Allocation Manual at 49

demands. Second, "excess" demand in the Complied COSS is based on CP demands, as opposed to NCP demands. NARUC states the A&E method should utilize NCP instead of CP demands. NARUC states:

> "If your objective is – as it should be using this method – to reflect the impact of average demand on production plant costs, then it is a mistake to allocate the excess demand with a coincidental peak allocator factor because it produces allocation factors that are identical to those derived using a CP method. Rather, use the NCP to allocate the excess demands."[5]

As described below, the Company's alternative COSS utilizes the A&E method described by NARUC to classify and allocate distribution costs. Specifically, the A&E method in the Alternative COSS (1) is based on "excess" demand as the difference between class peak and class average demand and (2) utilizes NCP demands rather than CP demands.

Q. How were rate base items classified and allocated in the Complied COSS?

A. Rate base items were classified and allocated in the Complied COSS in the following manner:

- Intangible plant (301-303)
  - Costs were classified based on the A&E method.
  - Demand costs were allocated based on the CP demands of each rate class. Energy costs were allocated based on kWh sales of each rate class.
- Distribution facilities – poles, towers, fixtures, and conductors (360-367)
  - Costs were functionalized in the manner described earlier.

[5] Id., at 50

- Costs were classified based on the A&E method.
- Demand costs were allocated based on the CP demands of each rate class. Energy costs were allocated based on kWh sales of each rate class.

- Transformers (368)
  - Costs were functionalized as 100% secondary.
  - Costs were classified based on the A&E method.
  - Demand costs were allocated based on the secondary voltage CP demands of each rate class. Energy costs were allocated based on kWh sales of each rate class.
- Services (369)
  - Costs were classified equally as customer and demand.
  - Customer costs were allocated based on the number of customers of each rate class. Demand costs were allocated based on the secondary voltage CP demands of each rate class.
- Meters (370)
  - Costs were classified as customer and demand based on a special study. Customer costs reflect only the equipment portion of the total meter costs.
  - Customer costs were allocated based on minimum meter costs calculated for each rate class. The costs in excess of class minimum meter costs were considered as demand costs for each rate class.
- Installation costs on customer premises (371 and 373)
  - Costs are associated with installation of lighting equipment on customer premises and are assigned to the lighting rate classes.

- General plant (389 through 399)
    - Costs were classified based on the A&E method.
    - Demand costs were allocated based on the CP demands of each rate class. Energy costs were allocated on kWh sales of each rate class.
- Service Company plant
    - Costs were classified based on the A&E method.
    - Demand costs were allocated based on the CP demands of each rate class. Energy costs were allocated on kWh sales of each rate class.
- Accumulated depreciation
    - Costs were classified and allocated based on the applicable plant items.
- Customer advances for construction, accumulated deferred income taxes, net/loss on required debt, material and supplies, excess cost of removal, customer refunds, net operating losses, and property-related unprotected amortization.
    - Costs were classified and allocated to each rate class in proportion to distribution plant in service.
- Customer deposits
    - Costs were classified as customer and allocated to non-lighting rate classes based on customer counts.
- Cash working capital
    - Costs were classified and allocated based on O&M expenses, excluding administrative and general ("A&G") expenses.
- Consolidated tax adjustment
    - Costs were classified and allocated based on plant in service.

- Net operating reserves
    - Costs were classified and allocated based on the labor portion of distribution O&M, customer service and A&G expenses.

Q. How were O&M expenses classified and allocated in the Complied COSS?

A. O&M expenses were classified and allocated in the Complied COSS in the following manner:

- Distribution O&M expenses (580-598)
    - Costs were classified and allocated based on their respective plant item.
- Supervision (901) and Miscellaneous customer account (905) expenses
    - Costs were classified as 100% energy and allocated based on weighted customer counts developed through customer billing study utilized in the Company's prior base rate proceedings.
- Meter reading (902) and Customer records and collection (903) expenses
    - Costs were classified and allocated based on Meters (370).
- Uncollectible expenses (904)
    - Costs were classified as 100% energy and allocated based on kWh sales of each rate class.
- Customer service costs (907-910) and sales expense (911)
    - Costs were classified based on the A&E method.
    - Demand costs were allocated based on the CP demands of each rate class. Energy costs were allocated on kWh sales of each rate class, excluding GT.
- A&G expenses (920-932)

- Costs were allocated to GT based on their portion of distribution plant and classified as customer.
- Remaining costs were classified based on the A&E method.
- Demand costs were allocated based on the CP demands of each rate class. Energy costs were allocated on kWh sales of each rate class.

- Depreciation and amortization expenses
  - Costs were classified and allocated based on the respective plant item.
- Property taxes
  - Costs were classified and allocated based on total plant.
- Payroll and unemployment taxes
  - Costs were classified and allocated based on labor.

Q. How were Other Operating Revenues allocated in the Complied COSS?

A. Other operating revenues were allocated in the Complied COSS in the following manner:

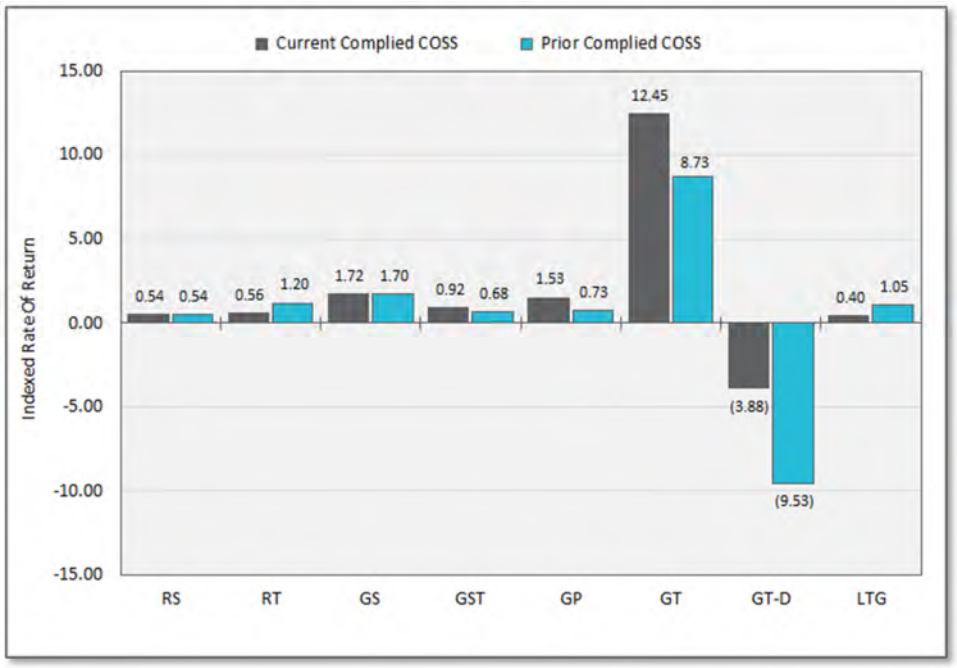
- Late payment fees (450) and service fees (451) were allocated to each rate class based on historical data.
- Rent from electric property (454) were classified and allocated based on a composite allocator developed based on the classification and allocation distribution plant.
- Other Electric Revenues (456) were classified and allocated based on retail distribution revenues.

Q. Have you compared the results of the Complied COSS in this rate case to the results of the Complied COSS in the prior rate case?

A. Yes. Figure 5 (below) compares the Unit RORs for each rate class in this rate case to the Unit RORs in Docket No. ER12111052 based on the allocation methods in the Complied COSS (where Unit ROR is the class ROR as a factor of the system or overall ROR). The comparison is based on the "Unit" ROR since the system or overall RORs in this rate case is different than in Docket No. ER12111052.

Figure 5: Comparison of Complied COSS

Indexed Rate of Return: Class ROR divided by System ROR



The Figure shows the results of the Complied COSS in this rate case are generally consistent with the results of the Complied COSS in Docket No. ER12111052.

The testimony of Company witness Yongmei Peng discusses utilization of the COSS results to develop the proposed rate design.

Q. Does the cost of service vary across the Company's rate classes?

A. Yes, the cost of service per customer and per kWh (i.e., unit cost of service) varies across the Company's rate classes, as shown in Figure 6 (below).

Figure 6: Unit Cost of Service by Rate Class (Complied COSS)

Rate Schedule	Revenue Requirements Per Customer	Per kWh
Residential Service (RS)	$ 497	$ 0.053
Residential Time of Day (RT)	573	0.042
General Service (GS)	1,839	0.037
General Time of Day (GST)	69,814	0.030
General Service Primary (GP)	43,461	0.016
General Service Transmission (GT)	50,048	0.005
[redacted]		
Lighting (LTG)	11,315	0.287

The Figure shows, for example, the unit cost of service for the Residential rate class is $496 per customer, while the unit cost of service for the GT-D rate class is [redacted] per customer. By comparison, the unit cost of service for the Residential rate class is $0.053 per kWh, while the unit cost of service for the GT-D rate class is [redacted] per kWh.

Q. How are variations in the unit cost of service used to support the Company's rate design?

A. Variations in the unit cost of service support the need for distinct rate classes and rate designs.

Q. How were the results of the Complied COSS used to inform the Company's proposed revenue requirements for each rate class.

A. The Complied COSS apportions the Company's overall revenue requirements to each rate class consistent with the Board's order in Docket No. ER12111052. Specifically, class

revenue requirements at the system ROR are determined as the sum of required return on allocated rate base and allocated expenses (such as O&M, taxes, and depreciation).

The Complied COSS study also determines class revenue requirements by cost classifications (i.e., customer, demand, and energy). The class revenue requirements by cost classification are utilized by Company Witness Yongmei Peng to develop the Company's proposed rates for each rate class.

V. Development of the Alternative COSS

Q. Why has the Company prepared an Alternative COSS?

A. The Company prepared an Alternative COSS to address concerns with certain methodologies in the Complied COSS.

Q. Which methodologies are of primary concern in the Complied COSS?

A. The Company has concerns with the following methodologies:

- The classification and allocation of distribution costs based on the A&E method does not follow NARUC convention, as described earlier.
- The classification of meter costs is not based on meter installation costs.
- The classification of services is not based on analysis of service costs.
- The classification of customer accounting and service expenses does not reflect that these costs vary directly and linearly with the number of customers.

Q. What is the Company's concern regarding the use of the A&E method in the Complied COSS?

A. As stated earlier, the A&E method used in the Complied COSS does not follow NARUC convention. First, "excess" demand in the Complied COSS is not based on the difference

(or excess) between class peak and class average demands. Second, "excess" demand in the Complied COSS is not allocated based on class NCP demands.

Q. What is the Company's recommendation regarding use of the A&E method in the Alternative COSS?

A. The Company recommends that the A&E method follow NARUC convention by (1) calculating excess demand as the difference between class peak and average demand and (2) utilizing NCP rather than CP demands.

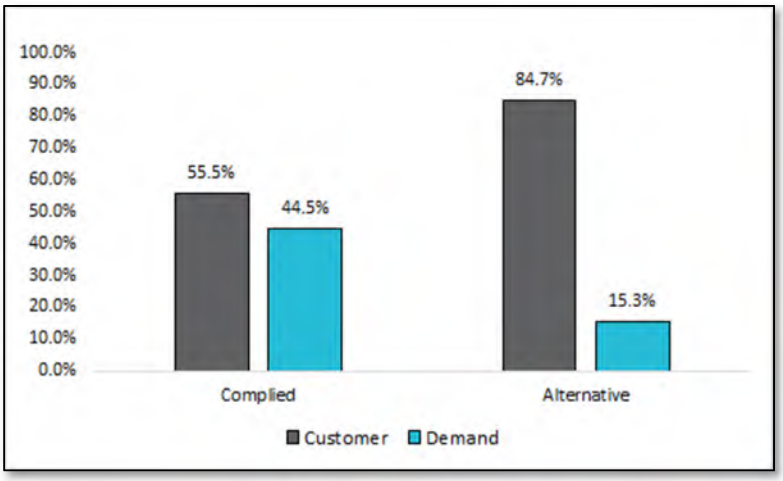
Q. What is the Company's concern regarding classification of meter costs in the Complied COSS?

A. The Company is concerned that the classification of meter costs is not based on the relative cost of purchasing and installing a minimum-sized meter as compared to an average-sized meter. Specifically, the customer component of the meter cost in the Complied COSS is based only on the relative purchase cost of a minimum-sized meter for each rate class as compared to an average-sized meter. The classification method does not include the relative cost of installing a minimum-sized meter for each rate class as compared to the cost of installing an average-sized meter. The Company believes the classification methodology should be based on the purchase and installation cost of a minimum-sized and average-sized meter since those costs are included in meter plant (370). In other words, the classification method should be based on the costs that are classified.

Q. What is the Company's recommendation regarding classification of meter costs in the Alternative COSS?

A. The Company recommends classification of meter costs in the Alternative COSS should be based on the relative cost of purchasing and installing a minimum-sized meter for each rate class as compared to the cost of purchasing and installing an average-sized meter. The impact of the change in classification method is shown in Figure 7 (below).

Figure 7: Meter Cost Classification



The Figure shows that the portion of meter costs classified as customer is 55.5 percent in the Complied COSS and 84.7 percent in the Alternative COSS.

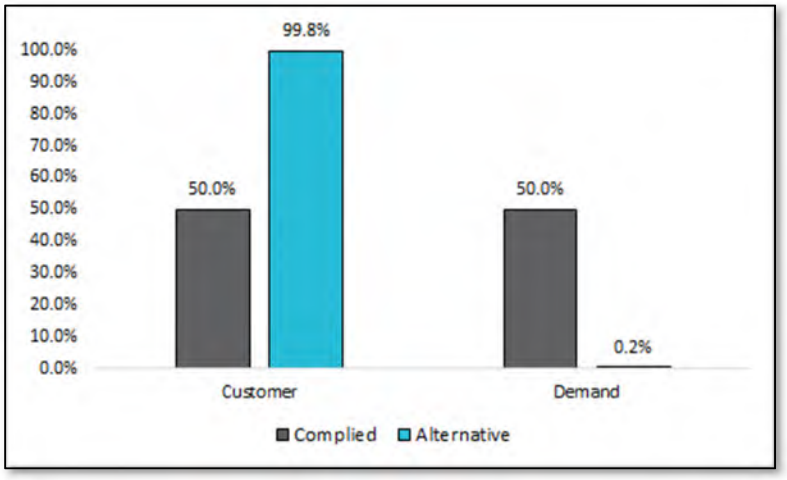
Q. What is the Company's concern regarding classification of service costs in the Complied COSS?

A. The Company is concerned that the classification of service costs in the Complied COSS is not based on an analysis of service costs; instead, the classification of service costs is based on 50.00 percent customer and 50.00 percent demand.

Q. What is the Company's recommendation regarding classification of service costs in the Alternative COSS?

A. The Company recommends classifying service costs based on the same methodology as meter costs. Specifically, the Company recommends classifying service costs in the Alternative COSS based on the relative cost of purchasing and installing a minimum-sized service line as compared to an average-sized service line. The impact of the change in classification method is shown in Figure 8 (below).

Figure 8: Service Line Cost Classification



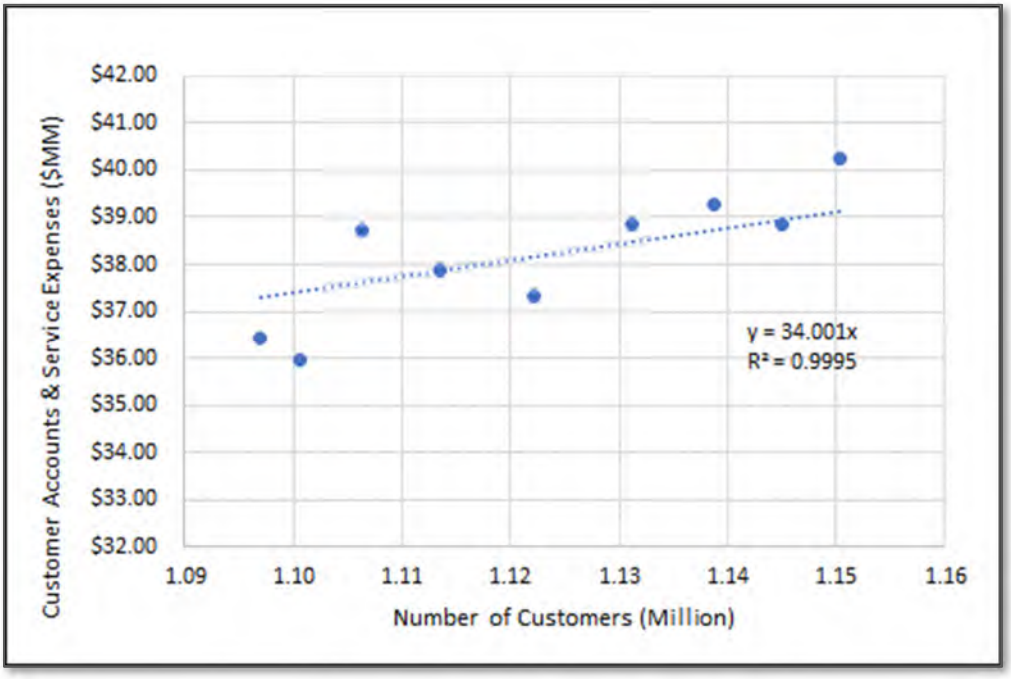
The Figure shows that the portion of service costs classified as customer is 50.0 percent in the Complied COSS and 99.8 percent in the Alternative COSS.

Q. What is the Company's concern regarding classification of customer accounting, excluding Uncollectible Expenses (904), and customer service expenses in the Complied COSS?

A. The Company is concerned that the classification of customer accounting and service expenses does not reflect that the costs vary directly and linearly with the number of

customers, shown in Figure 9 (below), consistent with the Board's guidance on classification of customer costs.[6]

Figure 9: Relationship between Customers and Customer Expenses[7]



The Figure shows there is a direct relationship between the changes in the number of customers and changes in customer accounting and service expenses.

Q. What is the Company's recommendation regarding classification of customer accounting and customer service expenses in the Alternative COSS?

[6] "…we herein reaffirm our policy that the classification of customer costs should be limited to those costs which are demonstrated to vary directly and linearly with the number of customers on the system, unaffected by demand or energy consumption." Board order in ER12111052 at p. 65.
[7] Includes Accounts 901, 902, 903, 905, 907, 909, and 910.

A. The Company recommends classifying customer accounting and service expenses as customer in the Alternative COSS since they vary directly and linearly with the number of customers. The Company's recommendation is also consistent with NARUC's guidance:

> "[Customer Account Expenses (901-905)] are generally classified as customer-related. The exception may be Account 904, Uncollectible Accounts…."[8]

> "[Customer Service and Informational Expenses (905-910)] include the costs of encouraging safe and efficient use of the utility's service. Except for conservation and load management, these costs are classified as customer-related. Emphasis is placed upon the costs of responding to customer inquiries and preparing billing inserts."[9]

The Company does not recommend a change to the classification of uncollectible expenses (904).

Q. What are the primary differences between the Alternative and Complied COSS?

A. There are two primary differences. First, the Alternative and Complied COSS produce variations in class RORs, as shown in Figure 1 (above). The Figure shows the ROR for some rate classes, such as RT, increasing from 1.8 percent in the Complied COSS to 4.5 percent in the Alternative COSS. The Figure also shows the ROR for some rate classes, such as GS, decreasing from 5.4 percent in the Complied COSS to 5.1 percent in the Alternative COSS.

[8] NARUC Electric Utility Cost Allocation Manual at 103
[9] Id.

Second, the Alternative and Complied COSS produce variations in classification of costs. Specifically, the Complied COSS classifies as customer 6.2 percent of the cost of service, whereas the Alternative COSS classifies as customer 12.9 percent of the cost of service.

VI. Electric Vehicle Rates

Q. Has the Company reviewed the Stipulation requirements approved by the Board in BPU Docket No. EO21030630 regarding development of electric vehicle ("EV") rates.[10]

A. Yes. The Stipulation requirements are presented below.

> "The Signatory Parties further agree that JCP&L will perform a Cost of Service Study ("COSS"), based upon EV Charging Data available to JCP&L, to develop and present an EV specific rate schedule or new EV provisions under the Company's existing residential and nonresidential rate schedules in its Next Base Rate Case for applicable customers."[11]
> "Commercial EV COSS. The Signatory Parties agree that the Company will perform a COSS based on the EV Charging Data available to JCP&L to develop and present a non-residential EV specific rate schedule or new EV provision under existing non-residential rate schedules in its Next Base Rate Case for commercial customers." [12]

Q. What is the Company's response to the Stipulation requirements?

A. The Company's response to the Stipulation requirements is to develop a COSS study based on EV charging data and to design an EV specific rate schedule which requires certain EV load data to perform the functionalization, classification, and allocation of costs to an EV specific rate schedule. According to NARUC,

[10] BPU Docket No. EO21030630, In the Matter of the Verified Petition of Jersey Central Power & Light Company for Approval of an Electric Vehicle Program and an Associated Cost Recovery Mechanism, Decision and Order Approving Stipulation ("EV Program Order").
[11] EV Program Order, at paragraph 54.
[12] Id., Paragraph 55

> "After the costs have been functionalized and classified, the next step is to allocate them among the customer classes. To accomplish this, the customers served by the utility are separated into several groups based on the nature of the service provided and load characteristics. The three principal customer classes are residential, commercial, and industrial. It may be reasonable to subdivide the three classes based on characteristics such as size of load, the voltage level at which the customer is served and other service characteristics such as whether a residential customer is all-electric or not." [13]

Presently, there is limited data to develop a COSS study and design a residential EV-specific rate, as shown in Figure 10 (below).

Figure 10: JCP&L Residential EV Charging

Residential EV Customers	Oct'22	Nov'22	Dec'22	Jan'23
Number of Chargers by Month	223	320	322	438
Charging kWh by Month	44,876	93,785	107,395	78,193
kWh per Charger	201	293	334	179

Specifically, the Figure shows the Company has only 4 months of residential EV data to develop a COSS study and design an EV specific rate. Further, the 4 months of residential EV data occur outside of the Company's system peak months of June through September, which would provide important information on whether EV demands contribute to the system peak demands.

Similarly, there is limited data to develop a COSS study and design a commercial Direct-current fast charger ("DCFC) rate, as shown in Figure 11 (below).

Figure 11: JCP&L DCFC Charging

DCFC Chargers	Jun'22	Jul'22	Aug'22	Sep'22	Oct'22	Nov'22	Dec'22	Jan'23
Number of Chargers by Month	7	7	10	10	13	13	13	13
Charging kWh by Month	381,093	454,148	444,768	603,345	726,894	764,594	892,285	748,944
kWh per Charger	54,442	64,878	44,477	60,334	55,915	58,815	68,637	57,611

[13] NARUC Electric Utility Cost Allocation Manual at pg. 22.

Specifically, the Figure shows the Company has only 8 months of DCFC charging residential EV data to develop a COSS study and design a DCFC rate. Further, there are only 7 (out of 13) chargers whose data is available during June and July, which are the Company's system peak months. The data provides only limited information on DCFC demands during system peak months.

Q. Does the Company believe it is appropriate to continue with its current EV rate provision while it continues to collect data to develop a COSS study and design an EV specific rate?

A. Yes. The current EV rate provisions are based on: 1) a time-period defined as the off-peak period (11:00 PM to 6:00 AM) for EV charging discount, and 2) a 2.0 cents discount provided to EV charging during the off-peak hours.[14]

Q. Is the current off-peak period appropriate for the EV charging discount?

A. Yes. The EV charging discount occurs during the Company's off-peak period – when system demands are lowest – as shown in Figure 12 (below).

[14] Jersey Central Power & Light Company, Tariff for Service, Original Sheet No. 69 (Rider EV – Electric Vehicle Charger Rider)

Figure 12: JCP&L 2022 Average System Hourly Loads (GW)

Month	Hour Ending 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	3.4	3.5	3.5	3.5	3.5	3.4	3.6	3.7	3.7	3.7	3.6	3.6	3.6	3.6	3.6	3.7	3.8	3.9	3.9	3.9	3.9	3.8	3.7	3.5
2	3.2	3.2	3.1	3.1	3.2	3.3	3.5	3.6	3.5	3.4	3.4	3.5	3.5	3.2	3.6	3.4	3.5	3.7	3.8	3.8	3.7	3.6	3.5	3.3
3	3.0	2.9	2.9	2.9	3.0	3.1	3.2	3.3	3.3	3.2	3.1	3.0	3.0	3.0	3.0	3.1	3.2	3.4	3.5	3.6	3.5	3.4	3.2	3.0
4	2.9	2.9	2.7	2.7	2.9	2.9	3.0	3.1	3.0	3.0	2.9	2.9	2.9	2.9	2.9	2.9	3.0	3.1	3.2	3.3	3.3	3.2	3.1	2.9
5	2.9	2.8	2.7	2.7	2.7	2.8	2.9	3.0	3.1	3.1	3.1	3.2	3.2	3.3	3.4	3.5	3.6	3.7	3.7	3.7	3.7	3.5	3.3	3.1
6	2.2	2.0	1.9	1.9	1.9	1.9	2.0	2.2	2.3	2.4	2.5	2.7	2.8	2.9	3.1	3.2	3.4	3.5	3.4	3.5	3.1	3.0	2.7	2.4
7	2.9	2.6	2.5	2.4	2.3	2.4	2.5	2.6	2.9	3.1	3.4	3.7	3.9	4.1	4.3	4.5	4.6	4.6	4.6	4.3	4.1	3.8	3.5	3.2
8	2.8	2.6	2.4	2.4	2.3	2.4	2.5	2.6	2.8	3.0	3.3	3.5	3.7	4.0	4.2	4.4	4.5	4.6	4.5	4.2	4.0	3.7	3.4	3.1
9	3.1	3.0	2.9	2.9	2.9	2.9	3.1	3.2	3.2	3.3	3.4	3.4	3.6	3.7	3.8	3.9	4.1	4.1	4.1	4.1	3.9	3.7	3.5	3.3
10	2.9	2.7	2.7	2.7	2.7	2.8	3.0	3.1	3.1	3.0	3.0	2.9	2.9	2.9	2.9	3.0	3.1	3.3	3.4	3.4	3.3	3.2	3.0	2.9
11	2.9	2.8	2.8	2.8	2.8	2.9	3.1	3.2	3.2	3.1	3.1	3.0	3.0	3.0	3.1	3.2	3.4	3.6	3.6	3.5	3.4	3.3	3.2	3.0
12	3.3	3.2	3.1	3.1	3.2	3.3	3.4	3.6	3.6	3.5	3.4	3.4	3.4	3.4	3.5	3.6	3.8	3.9	3.9	3.8	3.8	3.7	3.6	3.4

The Figure shows a 'heat map' of the Company's loads with the highest system loads represented by red and the lowest system load represented by green.

The Figure also shows the highest system loads generally occur during the daytime/ early evening hours from 7:00 AM through 11:00 PM and the lowest system loads generally occur during the late night/ early morning hours from 11:00 PM through 6:00 AM.

Consequently, the EV charging discount is offered concurrent with the lowest system loads from 11:00 PM through 6:00 AM. It is appropriate to offer customers an incentive to charge during this period since the distribution system has available capacity.

Q. Is the Company's 2.0 cents discount an appropriate incentive for customers to charge in the off-peak period?

A. Yes. The Company's 2.0 cents discount is an appropriate incentive for customers to charge in the off-peak period, as shown in Figure 13 (below).

Figure 13: JCP&L Residential Average EV Charging Loads per Charger (kWh)

Month	Hour Ending 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	13.3	11.6	11.7	10.5	11.5	10.2	8.6	6.6	4.7	4.0	3.3	2.6	2.7	2.8	3.1	3.3	3.8	4.8	5.6	6.3	9.0	10.6	11.0	16.7
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10	13.3	14.3	13.6	20.5	19.6	14.7	10.5	7.1	4.9	3.2	2.1	2.2	2.4	2.4	3.1	4.2	4.6	5.2	5.9	7.0	9.0	9.4	9.9	12.2
11	21.9	19.6	19.6	18.1	22.9	19.3	15.4	11.2	8.1	6.2	4.7	4.1	4.1	4.3	5.3	5.7	6.5	7.3	8.7	10.2	13.6	16.2	16.8	23.3
12	21.2	21.3	21.9	19.4	26.8	25.3	21.0	16.2	11.8	9.1	6.2	4.3	4.5	5.6	5.9	6.0	7.0	8.6	9.3	10.4	14.3	16.8	17.1	21.0

Based on only 9 months of data, the Figure shows that the highest charging loads (represented by red) occur in the off-peak period and the lowest charging loads (represented by green) occur in the peak period.

Q. **Does this conclude your Direct Testimony?**

A. Yes, it does.

Jersey Central Power & Light - First Energy Corp. COSS Summary Complied	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
Current Delivery Service Rates									
Rate base	$ 2,987,495,271	$ 1,813,647,170	$ 32,750,589	$ 851,009,430	$ 53,904,290	$ 89,220,227	$ 23,701,925		$ 120,970,245
Net operating income	$ 94,086,848	$ 30,916,954	$ 579,372	$ 46,206,790	$ 1,565,774	$ 4,291,803	$ 9,291,758		$ 1,514,451
Rate of return	**3.15%**	**1.70%**	**1.77%**	**5.43%**	**2.90%**	**4.81%**	**39.20%**		**1.25%**
Unitized Rate of Return	**1.00**	**0.54**	**0.56**	**1.72**	**0.92**	**1.53**	**12.45**		**0.40**
Relative rate of return	100%	54%	56%	172%	92%	153%	1245%		40%
Distribution Revenues	$ 642,676,612	$ 349,755,697	$ 6,912,701	$ 207,791,273	$ 10,889,186	$ 27,242,693	$ 20,523,970		$ 19,253,942
Other Operating Revenues	$ 12,445,306	$ 6,336,511	$ 95,102	$ 4,743,607	$ 245,562	$ 788,841	$ 103,174		$ 132,164
Total Operating Revenues	$ 655,121,918	$ 356,092,208	$ 7,007,803	$ 212,534,879	$ 11,134,748	$ 28,031,533	$ 20,627,144		$ 19,386,106
Test Period Usage (MWh)	20,178,644	9,422,567	195,504	6,496,218	441,097	1,594,495	1,708,916		112,498
Revenue per MWh	$ 32.47	$ 37.79	$ 35.84	$ 32.72	$ 25.24	$ 17.58	$ 12.07		$ 172.32
Revenues at Equalized Rates of Return									
Rate of return	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%		7.60%
Return requirement	$ 227,049,641	$ 137,837,185	$ 2,489,045	$ 64,676,717	$ 4,096,726	$ 6,780,737	$ 1,801,346		$ 9,193,739
Revenue required (Total)	$ 840,075,031	$ 504,819,752	$ 9,664,185	$ 238,226,807	$ 14,655,338	$ 31,493,676	$ 10,207,876		$ 30,068,103
Revenue required (Base)	$ 827,629,725	$ 498,483,241	$ 9,569,083	$ 233,483,200	$ 14,409,776	$ 30,704,835	$ 10,104,702		$ 29,935,938
Revenue deficiency / (surplus)	$ 184,953,113	$ 148,727,544	$ 2,656,382	$ 25,691,927	$ 3,520,590	$ 3,462,142	$ (10,419,268)		$ 10,681,997
Percent increase required	28.2%	41.8%	37.9%	12.1%	31.6%	12.4%	-50.5%		55.1%
Test Period Usage (MWh)	20,178,644	9,422,567	195,504	6,496,218	441,097	1,594,495	1,708,916		112,498
Revenue Required per MWh	$ 41.02	$ 52.90	$ 48.95	$ 35.94	$ 32.67	$ 19.26	$ 5.91		$ 266.10
Revenue deficiency / (surplus) per MWh	$ 9.17	$ 15.78	$ 13.59	$ 3.95	$ 7.98	$ 2.17	$ (6.10)		$ 94.95
Base Revenue Requirement at EROR									
Demand	446,189,220	282,915,215	5,389,545	108,368,914	6,197,260	11,804,009	3,253,165		27,858,275
Customer	51,501,789	40,585,592	553,186	5,138,880	84,941	2,536,964	2,575,359		-
Energy	329,938,716	174,982,434	3,626,353	119,975,406	8,127,576	16,363,862	4,276,178		2,077,664
Total Base Revenue Requirement	**827,629,725**	**498,483,241**	**9,569,083**	**233,483,200**	**14,409,776**	**30,704,835**	**10,104,702**		**29,935,938**

Rate Class	Class ROR	Overall ROR
RS	1.70%	3.15%
RT	1.77%	3.15%
GS	5.43%	3.15%
GST	2.90%	3.15%
GP	4.81%	3.15%
GT	39.20%	3.15%
[redacted]		
LTG	1.25%	3.15%

Jersey Central Power & Light - First Energy Corp. COSS Summary Complied	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
Current Rate of Return	3.15%	1.70%	1.77%	5.43%	2.90%	4.81%	39.20%		1.25%
Proposed Rate of Return	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%		7.60%
EROR Revenues	$ 840,075,031	$ 504,819,752	$ 9,664,185	$ 238,226,807	$ 14,655,338	$ 31,493,676	$ 10,207,876		$ 30,068,103
Current Revenues	655,121,918	356,092,208	7,007,803	212,534,879	11,134,748	28,031,533	20,627,144		19,386,106
Difference	$ 184,953,113	$ 148,727,544	$ 2,656,382	$ 25,691,927	$ 3,520,590	$ 3,462,142	$ (10,419,268)		$ 10,681,997
% Difference	28.23%	41.77%	37.91%	12.09%	31.62%	12.35%	-50.51%		55.10%
Derivation of Delivery Revenues									
Current Total Revenues	$ 655,121,918	356,092,208	7,007,803	212,534,879	11,134,748	28,031,533	20,627,144		19,386,106
Other Revenues	$ 12,445,306	6,336,511	95,102	4,743,607	245,562	788,841	103,174		132,164
Current Delivery Revenues	$ 642,676,612	$ 349,755,697	$ 6,912,701	$ 207,791,273	$ 10,889,186	$ 27,242,693	$ 20,523,970		$ 19,253,942
Total Revenues at EROR	$ 840,075,031	504,819,752	9,664,185	238,226,807	14,655,338	31,493,676	10,207,876		30,068,103
Other Revenues	12,445,306	6,336,511	95,102	4,743,607	245,562	788,841	103,174		132,164
Delivery Revenues at EROR	$ 827,629,725	$ 498,483,241	$ 9,569,083	$ 233,483,200	$ 14,409,776	$ 30,704,835	$ 10,104,702		$ 29,935,938
Metrics									
Total Revenues at EROR	827,629,725	498,483,241	9,569,083	233,483,200	14,409,776	30,704,835	10,104,702		29,935,938
Test Period Usage (MWh)	20,178,644	9,422,567	195,504	6,496,218	441,097	1,594,495	1,708,916		112,498
Test Period Customers	1,153,297	1,005,454	14,230	129,795	188	599	172		2,857
Revenue requirement per kWh		$ 0.053	$ 0.049	$ 0.036	$ 0.033	$ 0.019	$ 0.006		$ 0.266
Revenue requirement per Customer		$ 496	$ 672	$ 1,799	$ 76,738	$ 51,251	$ 58,621		$ 10,480

Jersey Central Power & Light - First Energy Corp. Revenue Requirements by Cost Classification (At EROR)	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG
Demand									
Rate Base	1,653,723,168	1,059,438,732	17,889,138	394,524,131	23,709,033	35,674,914	8,184,052		113,313,529
Required Return on Rate Base	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%		7.60%
Required Net Income	$ 125,682,961	$ 80,517,344	$ 1,359,574	$ 29,983,834	$ 1,801,887	$ 2,711,293	$ 621,988		$ 8,611,828
Total Operating Expenses	165,379,464	105,278,724	2,346,695	43,855,406	2,288,591	5,201,296	148,900		6,243,962
Depreciation & Amortization	128,916,428	79,088,079	1,351,893	29,581,903	1,767,623	3,610,899	2,419,363		10,804,110
Total Other Taxes	4,836,875	3,099,024	59,099	1,207,671	68,415	120,585	14,348		265,997
Total Expenses	$ 299,132,766	$ 187,465,827	$ 3,757,688	$ 74,644,980	$ 4,124,630	$ 8,932,780	$ 2,582,611		$ 17,314,069
Interest Expense	36,367,555	23,298,456	393,406	8,676,106	521,393	784,538	179,978		2,491,914
Income Taxes	34,923,578	22,373,389	377,786	8,331,621	500,691	753,388	172,832		2,392,972
Income Tax Amortization	(5,197,990)	(3,330,033)	(56,229)	(1,240,070)	(74,522)	(112,134)	(25,724)		(356,168)
Revenue Requirement (Demand)	$ 454,541,316	$ 287,026,527	$ 5,438,819	$ 111,720,365	$ 6,352,685	$ 12,285,328	$ 3,351,707		$ 27,962,702
Less: Other Revenues (Demand)	$ 8,352,095	$ 4,111,313	$ 49,274	$ 3,351,451	$ 155,425	$ 481,320	$ 98,542		$ 104,427
Base Revenue Requirement (Demand)	**$ 446,189,220**	**$ 282,915,215**	**$ 5,389,545**	**$ 108,368,914**	**$ 6,197,260**	**$ 11,804,009**	**$ 3,253,165**		**$ 27,858,275**
Customer									
Rate Base	138,841,265	112,550,359	1,549,432	14,320,290	178,078	5,136,353	5,052,215		-
Required Return on Rate Base	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%		7.60%
Required Net Income	$ 10,551,936	$ 8,553,827	$ 117,757	$ 1,088,342	$ 13,534	$ 390,363	$ 383,968		$ -
Total Operating Expenses	26,548,812	20,352,847	275,270	2,572,526	52,954	1,610,003	1,668,175		-
Depreciation & Amortization	11,392,761	9,248,663	127,382	1,177,036	14,418	416,586	404,267		-
Total Other Taxes	563,986	443,808	6,044	56,151	940	28,100	28,645		-
Total Expenses	$ 38,505,559	$ 30,045,318	$ 408,696	$ 3,805,713	$ 68,312	$ 2,054,688	$ 2,101,088		$ -
Interest Expense	3,053,303	2,475,131	34,074	314,922	3,916	112,955	111,105		-
Income Taxes	2,932,071	2,376,856	32,721	302,418	3,761	108,470	106,693		-
Income Tax Amortization	(436,406)	(353,769)	(4,870)	(45,012)	(560)	(16,145)	(15,880)		-
Revenue Requirement (Customer)	$ 51,553,160	$ 40,622,232	$ 554,303	$ 5,151,461	$ 85,047	$ 2,537,377	$ 2,575,869		$ -
Less: Other Revenues (Customer)	$ 51,371	$ 36,640	$ 1,118	$ 12,581	$ 106	$ 412	$ 510		$ -
Base Revenue Requirement (Customer)	**$ 51,501,789**	**$ 40,585,592**	**$ 553,186**	**$ 5,138,880**	**$ 84,941**	**$ 2,536,964**	**$ 2,575,359**		**$ -**

Jersey Central Power & Light - First Energy Corp. Revenue Requirements by Cost Classification (At EROR)	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
Energy									
Rate Base	1,194,930,837	641,658,079	13,312,019	442,165,010	30,017,179	48,408,961	10,465,658		7,656,716
Required Return on Rate Base	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%		7.60%
Required Net Income	$ 90,814,744	$ 48,766,014	$ 1,011,713	$ 33,604,541	$ 2,281,306	$ 3,679,081	$ 795,390		$ 581,910
Total Operating Expenses	122,512,297	65,657,321	1,357,506	44,501,598	3,000,001	7,013,786	186,207		774,556
Depreciation & Amortization	95,657,954	49,325,186	1,023,421	34,006,355	2,309,052	4,944,503	3,092,029		588,901
Total Other Taxes	3,516,741	1,888,701	39,139	1,294,593	87,690	163,452	18,554		22,404
Total Expenses	$ 221,686,992	$ 116,871,208	$ 2,420,066	$ 79,802,547	$ 5,396,743	$ 12,121,741	$ 3,296,790		$ 1,385,861
Interest Expense	26,278,106	14,110,908	292,749	9,723,792	660,117	1,064,577	230,154		168,381
Income Taxes	25,234,732	13,550,633	281,125	9,337,708	633,907	1,022,308	221,015		161,696
Income Tax Amortization	(3,755,912)	(2,016,863)	(41,842)	(1,389,815)	(94,350)	(152,159)	(32,896)		(24,067)
Revenue Requirement (Energy)	$ 333,980,555	$ 177,170,992	$ 3,671,063	$ 121,354,981	$ 8,217,606	$ 16,670,971	$ 4,280,299		$ 2,105,400
Less: Other Revenues (Energy)	$ 4,041,839	$ 2,188,558	$ 44,710	$ 1,379,574	$ 90,030	$ 307,109	$ 4,122		$ 27,737
Base Revenue Requirement (Energy)	**$ 329,938,716**	**$ 174,982,434**	**$ 3,626,353**	**$ 119,975,406**	**$ 8,127,576**	**$ 16,363,862**	**$ 4,276,178**		**$ 2,077,664**

Jersey Central Power & Light - First Energy Corp. Income Statement Current Rates	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
Operating Revenues	**655,121,918**	**356,092,208**	**7,007,803**	**212,534,879**	**11,134,748**	**28,031,533**	**20,627,144**		**19,386,106**
Operating Expenses									
O&M Expenses	314,440,573	191,288,892	3,979,472	90,929,530	5,341,546	13,825,085	2,003,282		7,018,518
Depreciation & Amortization	235,967,143	137,661,927	2,502,697	64,765,294	4,091,094	8,971,988	5,915,659		11,393,011
Taxes Other than Income	8,917,602	5,431,533	104,282	2,558,416	157,045	312,136	61,548		288,401
Total Operating Expenses	559,325,317	334,382,353	6,586,450	158,253,239	9,589,685	23,109,209	7,980,489		18,699,930
Income Before Tax	95,796,600	21,709,855	421,353	54,281,640	1,545,063	4,922,324	12,646,656		686,176
Interest Expense	65,698,964	39,884,495	720,229	18,714,821	1,185,426	1,962,071	521,237		2,660,295
Taxable Income	30,097,636	(18,174,640)	(298,876)	35,566,819	359,637	2,960,254	12,125,419		(1,974,120)
State Income Taxes	2,708,787	(1,635,718)	(26,899)	3,201,014	32,367	266,423	1,091,288		(177,671)
Federal Income Taxes	5,751,658	(3,473,174)	(57,115)	6,796,819	68,727	565,704	2,317,168		(377,254)
Total Income Taxes	8,460,446	(5,108,891)	(84,014)	9,997,833	101,094	832,127	3,408,455		(554,925)
Amortization of Fed Income Tax Credit	(97,035)	(58,908)	(1,064)	(27,641)	(1,751)	(2,898)	(770)		(3,929)
Federal Tax Reform Amortization	(6,653,658)	(4,039,299)	(72,941)	(1,895,342)	(120,054)	(198,709)	(52,788)		(269,421)
Total Operating Income	**94,086,848**	**30,916,954**	**579,372**	**46,206,790**	**1,565,774**	**4,291,803**	**9,291,758**		**1,514,451**

Jersey Central Power & Light - First Energy Corp. Allocation Summary	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
Revenue Requirement									
Primary									
- Demand	153,629,725	103,603,023	1,487,843	36,559,611	2,358,706	8,329,518	1,146,710		6,394
- Customer	62,519	16,978	518	5,830	49	191	38,951		-
- Commodity	137,155,962	70,280,273	1,457,883	48,393,551	3,284,263	11,268,488	1,458,121		839,832
Secondary									
- Demand	213,353,587	150,395,679	2,159,833	53,076,295	3,424,371	2,447,758	1,642,355		9,841
- Customer	15,283,646	13,321,863	188,972	1,725,333	2,559	294	44,622		-
- Commodity	169,441,206	92,638,133	1,921,599	63,775,475	4,327,795	3,335,013	2,087,577		1,107,167
Customer Service									
- Demand	87,558,004	33,027,826	1,791,143	22,084,458	569,609	1,508,052	562,643		27,946,468
- Customer	36,206,994	27,283,391	364,813	3,420,298	82,439	2,536,892	2,492,296		-
- Commodity	27,383,388	14,252,587	291,581	9,185,955	605,548	2,067,470	734,601		158,401
		37.72%							
Total Revenue Requirement									
- Demand	**454,541,316**	**287,026,527**	**5,438,819**	**111,720,365**	**6,352,685**	**12,285,328**	**3,351,707**		**27,962,702**
- Customer	**51,553,160**	**40,622,232**	**554,303**	**5,151,461**	**85,047**	**2,537,377**	**2,575,869**		**-**
- Commodity	**333,980,555**	**177,170,992**	**3,671,063**	**121,354,981**	**8,217,606**	**16,670,971**	**4,280,299**		**2,105,400**
Total Revenue Requirement	**840,075,031**	**504,819,752**	**9,664,185**	**238,226,807**	**14,655,338**	**31,493,676**	**10,207,876**		**30,068,103**
Rate Base									
Primary									
- Demand	554,192,731	374,823,915	5,382,847	132,085,988	8,519,131	30,099,730	2,927,159		-
- Customer	18,334	-	-	-	-	-	18,334		-
- Commodity	493,394,955	253,533,266	5,260,423	174,793,914	11,868,613	40,724,903	3,741,010		3,026,974
Secondary									
- Demand	866,871,761	620,100,689	8,905,267	218,520,242	14,093,868	2,724,619	2,254,460		-
- Customer	96,188,288	84,093,879	1,190,185	10,855,769	15,705	-	32,750		-
- Commodity	649,315,706	363,127,469	7,534,333	250,351,650	16,999,029	3,743,123	2,881,277		4,335,436
Customer Service									
- Demand	232,658,676	64,514,128	3,601,024	43,917,900	1,096,034	2,850,565	3,002,434		113,313,529
- Customer	42,634,643	28,456,480	359,247	3,464,521	162,373	5,136,353	5,001,130		-
- Commodity	52,220,176	24,997,345	517,263	17,019,447	1,149,537	3,940,934	3,843,371		294,307
Total Rate Base									
- Demand	**1,653,723,168**	**1,059,438,732**	**17,889,138**	**394,524,131**	**23,709,033**	**35,674,914**	**8,184,052**		**113,313,529**
- Customer	**138,841,265**	**112,550,359**	**1,549,432**	**14,320,290**	**178,078**	**5,136,353**	**5,052,215**		**-**
- Commodity	**1,194,930,837**	**641,658,079**	**13,312,019**	**442,165,010**	**30,017,179**	**48,408,961**	**10,465,658**		**7,656,716**
Total Rate Base	**2,987,495,271**	**1,813,647,170**	**32,750,589**	**851,009,430**	**53,904,290**	**89,220,227**	**23,701,925**		**120,970,245**

Jersey Central Power & Light - First Energy Corp. Allocation Summary	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
Total Expenses									
Primary									
- Demand	101,549,492	68,378,965	981,990	24,146,837	1,558,121	5,500,897	871,630		6,394
- Customer	60,796	16,978	518	5,830	49	191	37,228		-
- Commodity	90,789,196	46,454,497	963,535	31,967,302	2,168,911	7,441,368	1,106,560		555,372
Secondary									
- Demand	131,889,358	92,121,748	1,322,961	32,540,867	2,099,900	2,191,712	1,430,492		9,841
- Customer	6,244,357	5,419,145	77,125	705,163	1,083	294	41,544		-
- Commodity	108,421,796	58,513,248	1,213,561	40,248,692	2,730,312	2,983,253	1,816,809		699,745
Customer Service									
- Demand	65,693,917	26,965,114	1,452,737	17,957,276	466,609	1,240,171	280,489		17,297,835
- Customer	32,200,406	24,609,194	331,053	3,094,720	67,180	2,054,203	2,022,315		-
- Commodity	22,476,000	11,903,462	242,971	7,586,553	497,520	1,697,121	373,420		130,744
Total Expenses									
- Demand	**299,132,766**	**187,465,827**	**3,757,688**	**74,644,980**	**4,124,630**	**8,932,780**	**2,582,611**		**17,314,069**
- Customer	**38,505,559**	**30,045,318**	**408,696**	**3,805,713**	**68,312**	**2,054,688**	**2,101,088**		**-**
- Commodity	**221,686,992**	**116,871,208**	**2,420,066**	**79,802,547**	**5,396,743**	**12,121,741**	**3,296,790**		**1,385,861**
Total Expenses	**559,325,317**	**334,382,353**	**6,586,450**	**158,253,239**	**9,589,685**	**23,109,209**	**7,980,489**		**18,699,930**

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Total System	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
UTILITY PLANT									
Intangible Plant									
(301) Organizational Costs	51,634								
- Demand	26,735	17,010	244	5,994	387	1,366	1,548		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	24,899	11,757	244	8,105	550	1,888	1,978		140
Total	51,634	28,766	488	14,099	937	3,254	3,525		140
(302) Franchises & Consents	2,742								
- Demand	1,420	903	13	318	21	73	82		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	1,322	624	13	430	29	100	105		7
Total	2,742	1,528	26	749	50	173	187		7
(303) Misc. Intangible Plant	182,308,711								
- Demand	94,396,997	60,057,655	862,488	21,164,004	1,365,012	4,822,849	5,464,238		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	87,911,713	41,509,912	861,266	28,618,257	1,943,197	6,667,713	6,983,484		495,593
Total	182,308,711	101,567,567	1,723,755	49,782,260	3,308,209	11,490,563	12,447,722		495,593
Total Intangible Plant	182,363,086								
- Demand	94,425,152	60,075,568	862,745	21,170,316	1,365,419	4,824,288	5,465,868		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	87,937,934	41,522,293	861,523	28,626,792	1,943,777	6,669,702	6,985,567		495,741
Total	182,363,086	101,597,861	1,724,269	49,797,108	3,309,195	11,493,990	12,451,434		495,741
Distribution Plant									
(360) Land and Land Rights	32,657,627								
- Demand	17,546,358	12,287,558	176,462	4,330,071	279,276	472,991	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	15,111,269	8,181,559	169,755	5,640,628	383,002	638,645	-		97,681
Total	32,657,627	20,469,117	346,216	9,970,699	662,278	1,111,635	-		97,681
(361) Structures and Improvements	91,400,169								
- Demand	49,107,674	34,389,667	493,870	12,118,739	781,621	1,323,778	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	42,292,496	22,898,047	475,099	15,786,643	1,071,923	1,787,400	-		273,383
Total	91,400,169	57,287,714	968,969	27,905,382	1,853,543	3,111,177	-		273,383
(362) Station Equipment	589,900,638								
- Demand	316,943,045	221,952,393	3,187,459	78,214,863	5,044,613	8,543,718	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	272,957,593	147,784,985	3,066,310	101,887,679	6,918,235	11,535,955	-		1,764,428
Total	589,900,638	369,737,378	6,253,769	180,102,542	11,962,848	20,079,673	-		1,764,428
(364) Poles, Towers & Fixtures	791,658,782								
- Demand	425,344,082	297,864,674	4,277,635	104,965,954	6,769,974	11,465,845	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	366,314,700	198,330,488	4,115,051	136,735,359	9,284,414	15,481,489	-		2,367,899
Total	791,658,782	496,195,162	8,392,686	241,701,313	16,054,388	26,947,334	-		2,367,899
(365) Overhead Conductors & Devices	1,272,980,404								
- Demand	683,949,567	478,963,793	6,878,400	168,784,337	10,886,059	18,436,979	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	589,030,837	318,913,692	6,616,966	219,869,263	14,929,257	24,894,099	-		3,807,561
Total	1,272,980,404	797,877,485	13,495,366	388,653,600	25,815,315	43,331,078	-		3,807,561
(366) Underground Conduit	124,359,206								
- Demand	66,108,679	45,244,589	649,758	15,943,957	1,028,335	3,242,041	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	58,250,527	30,455,115	631,897	20,996,727	1,425,691	4,377,490	-		363,608
Total	124,359,206	75,699,704	1,281,654	36,940,684	2,454,026	7,619,531	-		363,608
(367) Underground Conductors & Device	695,373,903								
- Demand	373,611,941	261,637,116	3,757,371	92,199,552	5,946,581	10,071,321	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	321,761,962	174,208,698	3,614,561	120,105,028	8,155,204	13,598,565	-		2,079,905
Total	695,373,903	435,845,814	7,371,932	212,304,581	14,101,786	23,669,886	-		2,079,905
(368) Line Transformers	909,589,450								
- Demand	495,172,748	356,371,647	5,117,854	125,583,506	8,099,741	-	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	414,416,702	234,275,046	4,860,845	161,516,683	10,967,081	-	-		2,797,047
Total	909,589,450	590,646,694	9,978,699	287,100,189	19,066,822	-	-		2,797,047
(369) Services	483,989,081								
- Demand	241,994,541	174,161,428	2,501,133	61,373,577	3,958,403	-	-		-
- Customer	241,994,541	211,638,975	2,995,338	27,320,701	39,526	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	483,989,081	385,800,404	5,496,471	88,694,278	3,997,928	-	-		-
(370) Meters	200,512,098								
- Demand	89,218,324	40,573,392	4,322,404	43,918,093	404,434	-	-		-
- Customer	111,293,775	84,960,239	1,141,623	10,675,430	235,477	7,208,935	6,995,765		-
- Commodity	-	-	-	-	-	-	-		-
Total	200,512,098	125,533,631	5,464,028	54,593,524	639,911	7,208,935	6,995,765		-
(371) Installation on Customers' Premises	27,149,890								
- Demand	27,149,890	-	-	-	-	-	-		27,149,890
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	27,149,890	-	-	-	-	-	-		27,149,890
(373) Street Lighting & Signal Systems	265,095,805								
- Demand	265,095,805	-	-	-	-	-	-		265,095,805
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	265,095,805	-	-	-	-	-	-		265,095,805

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Total System	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
(374) Asset Retirement Costs	45,657								
- Demand	24,206	16,469	237	5,804	374	1,323	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	21,451	11,117	231	7,664	520	1,786	-		133
Total	45,657	27,586	467	13,468	895	3,108	-		133
(375) Charging Stations	-								
- Demand	-	-	-	-	-	-	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	-	-	-	-	-	-	-		-
Total Distribution Plant	5,484,712,711								
- Demand	3,051,266,859	1,923,462,725	31,362,582	707,438,453	43,199,410	53,557,994	-		292,245,694
- Customer	353,288,315	296,599,214	4,136,961	37,996,132	275,003	7,208,935	6,995,765		-
- Commodity	2,080,157,537	1,135,058,748	23,550,713	782,545,675	53,135,327	72,315,428	-		13,551,645
Total	5,484,712,711	3,355,120,688	59,050,256	1,527,980,260	96,609,740	133,082,357	6,995,765		305,797,340
General Plant									
(389) Land and Land Rights	1,497,070								
- Demand	775,163	493,177	7,083	173,793	11,209	39,604	44,871		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	721,907	340,868	7,072	235,005	15,957	54,753	57,346		4,070
Total	1,497,070	834,045	14,155	408,798	27,166	94,357	102,217		4,070
(390) Structures and Improvements	105,831,624								
- Demand	54,798,191	34,863,936	500,681	12,285,869	792,400	2,799,701	3,172,033		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	51,033,433	24,096,827	499,972	16,613,120	1,128,041	3,870,660	4,053,967		287,696
Total	105,831,624	58,960,762	1,000,653	28,898,989	1,920,441	6,670,361	7,225,999		287,696
(391) Office Furniture & Equipment	35,911,125								
- Demand	18,594,297	11,830,142	169,893	4,168,880	268,880	950,004	1,076,344		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	17,316,828	8,176,612	169,652	5,637,217	382,770	1,313,405	1,375,605		97,622
Total	35,911,125	20,006,754	339,545	9,806,097	651,650	2,263,408	2,451,949		97,622
(392) Transportation Equipment	17,437,527								
- Demand	9,028,917	5,744,415	82,496	2,024,302	130,561	461,298	522,645		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	8,408,610	3,970,354	82,379	2,737,289	185,864	637,756	667,959		47,403
Total	17,437,527	9,714,770	164,874	4,761,591	316,425	1,099,053	1,190,604		47,403
(393) Stores Equipment	1,120,889								
- Demand	580,381	369,253	5,303	130,123	8,393	29,652	33,596		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	540,508	255,216	5,295	175,954	11,947	40,995	42,937		3,047
Total	1,120,889	624,468	10,598	306,076	20,340	70,647	76,532		3,047
(394) Tools, Shop & Garage Equipment	24,160,384								
- Demand	12,509,922	7,959,115	114,301	2,804,751	180,898	639,146	724,146		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	11,650,462	5,501,084	114,139	3,792,622	257,521	883,636	925,483		65,678
Total	24,160,384	13,460,199	228,440	6,597,373	438,419	1,522,782	1,649,629		65,678
(395) Laboratory Equipment	427,250								
- Demand	221,224	140,748	2,021	49,599	3,199	11,303	12,806		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	206,026	97,281	2,018	67,068	4,554	15,626	16,366		1,161
Total	427,250	238,029	4,040	116,667	7,753	26,929	29,172		1,161
(396) Power Operated Equipment	2,049,275								
- Demand	1,061,087	675,089	9,695	237,898	15,344	54,212	61,422		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	988,188	466,600	9,681	321,689	21,843	74,950	78,499		5,571
Total	2,049,275	1,141,689	19,376	559,587	37,187	129,162	139,921		5,571
(397) Communication Equipment	65,188,679								
- Demand	33,753,821	21,474,998	308,402	7,567,677	488,091	1,724,521	1,953,864		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	31,434,858	14,842,825	307,966	10,233,117	694,835	2,384,195	2,497,105		177,211
Total	65,188,679	36,317,823	616,368	17,800,794	1,182,926	4,108,715	4,450,970		177,211
(398) Misc. Equipment	175,681								
- Demand	90,965	57,874	831	20,395	1,315	4,648	5,266		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	84,716	40,001	830	27,578	1,873	6,425	6,730		478
Total	175,681	97,875	1,661	47,973	3,188	11,073	11,995		478
(399) Other Tangible Property	1,460,782								
- Demand	756,373	481,223	6,911	169,580	10,937	38,644	43,783		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	704,409	332,606	6,901	229,309	15,570	53,426	55,956		3,971
Total	1,460,782	813,829	13,812	398,890	26,508	92,070	99,740		3,971
(SRVCO-PIS) Service Company PIS	139,697,969								
- Demand	72,333,729	46,020,469	660,900	16,217,373	1,045,970	3,695,612	4,187,090		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	67,364,240	31,807,863	659,964	21,929,354	1,489,016	5,109,279	5,351,245		379,759
Total	139,697,969	77,828,332	1,320,864	38,146,727	2,534,986	8,804,891	9,538,334		379,759
Total General Plant	394,958,255								
- Demand	204,504,070	130,110,440	1,868,516	45,850,239	2,957,196	10,448,344	11,837,865		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	190,454,185	89,928,136	1,865,870	61,999,323	4,209,792	14,445,105	15,129,198		1,073,666
Total	394,958,255	220,038,577	3,734,386	107,849,562	7,166,988	24,893,449	26,967,063		1,073,666
Total Utility Plant	6,062,034,052								
- Demand	3,350,196,082	2,113,648,733	34,093,843	774,459,008	47,522,025	68,830,626	17,303,733		292,245,694
- Customer	353,288,315	296,599,214	4,136,961	37,996,132	275,003	7,208,935	6,995,765		-
- Commodity	2,358,549,655	1,266,509,178	26,278,107	873,171,791	59,288,895	93,430,235	22,114,764		15,121,052
Total	6,062,034,052	3,676,757,125	64,508,911	1,685,626,930	107,085,923	169,469,795	46,414,262		307,366,747

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Total System	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
Additions to Utility Plant									
Construction Work in Progress	-								
- Demand	-	-	-	-	-	-	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	-	-	-	-	-	-	-		-
Total Additional to Utility Plant	-								
- Demand	-	-	-	-	-	-	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	-	-	-	-	-	-	-		-
Total Utility Plant	6,062,034,052								
- Demand	3,350,196,082	2,113,648,733	34,093,843	774,459,008	47,522,025	68,830,626	17,303,733		292,245,694
- Customer	353,288,315	296,599,214	4,136,961	37,996,132	275,003	7,208,935	6,995,765		-
- Commodity	2,358,549,655	1,266,509,178	26,278,107	873,171,791	59,288,895	93,430,235	22,114,764		15,121,052
Total	**6,062,034,052**	**3,676,757,125**	**64,508,911**	**1,685,626,930**	**107,085,923**	**169,469,795**	**46,414,262**		**307,366,747**
ACCUMULATED DEPRECIATION									
Accumulated Depreciation									
(108-303) Misc Intangible Plant	(116,359,793)								
- Demand	(60,249,535)	(38,332,213)	(550,489)	(13,508,071)	(871,228)	(3,078,217)	(3,487,588)		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	(56,110,258)	(26,493,988)	(549,709)	(18,265,800)	(1,240,259)	(4,255,714)	(4,457,257)		(316,316)
Total	(116,359,793)	(64,826,201)	(1,100,198)	(31,773,871)	(2,111,487)	(7,333,931)	(7,944,844)		(316,316)
(108-360) Land & Land Rights	(18,452,075)								
- Demand	(9,913,969)	(6,942,664)	(99,704)	(2,446,559)	(157,795)	(267,247)	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	(8,538,106)	(4,622,710)	(95,914)	(3,187,044)	(216,402)	(360,844)	-		(55,191)
Total	(18,452,075)	(11,565,374)	(195,618)	(5,633,602)	(374,198)	(628,092)	-		(55,191)
(108-361) Struct & Impmnts	(17,177,516)								
- Demand	(9,229,172)	(6,463,107)	(92,817)	(2,277,565)	(146,896)	(248,787)	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	(7,948,345)	(4,303,401)	(89,289)	(2,966,902)	(201,454)	(335,919)	-		(51,379)
Total	(17,177,516)	(10,766,508)	(182,106)	(5,244,467)	(348,350)	(584,707)	-		(51,379)
(108-362) Station Equip	(204,667,338)								
- Demand	(109,964,094)	(77,006,876)	(1,105,896)	(27,136,821)	(1,750,240)	(2,964,262)	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	(94,703,244)	(51,274,329)	(1,063,863)	(35,350,157)	(2,400,297)	(4,002,425)	-		(612,172)
Total	(204,667,338)	(128,281,205)	(2,169,759)	(62,486,977)	(4,150,537)	(6,966,687)	-		(612,172)
(108-364) Poles, Towers & Fixt	(302,580,911)								
- Demand	(162,571,303)	(113,847,236)	(1,634,960)	(40,119,171)	(2,587,560)	(4,382,375)	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	(140,009,608)	(75,804,149)	(1,572,819)	(52,261,796)	(3,548,608)	(5,917,200)	-		(905,038)
Total	(302,580,911)	(189,651,385)	(3,207,779)	(92,380,967)	(6,136,168)	(10,299,575)	-		(905,038)
(108-365) OH Cond & Dev	(195,375,322)								
- Demand	(104,971,660)	(73,510,719)	(1,055,688)	(25,904,793)	(1,670,778)	(2,829,683)	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	(90,403,661)	(48,946,445)	(1,015,563)	(33,745,239)	(2,291,322)	(3,820,713)	-		(584,379)
Total	(195,375,322)	(122,457,164)	(2,071,251)	(59,650,032)	(3,962,100)	(6,650,396)	-		(584,379)
(108-366) UG Conduit	(62,021,124)								
- Demand	(32,970,093)	(22,564,636)	(324,051)	(7,951,660)	(512,857)	(1,616,889)	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	(29,051,031)	(15,188,747)	(315,143)	(10,471,606)	(711,028)	(2,183,166)	-		(181,341)
Total	(62,021,124)	(37,753,383)	(639,194)	(18,423,266)	(1,223,885)	(3,800,055)	-		(181,341)
(108-367) UG Cond & Dev	(234,990,019)								
- Demand	(126,255,928)	(88,415,902)	(1,269,741)	(31,157,302)	(2,009,548)	(3,403,435)	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	(108,734,091)	(58,870,926)	(1,221,481)	(40,587,492)	(2,755,915)	(4,595,408)	-		(702,869)
Total	(234,990,019)	(147,286,828)	(2,491,222)	(71,744,794)	(4,765,463)	(7,998,843)	-		(702,869)
(108-368) Line Transformers	(315,307,756)								
- Demand	(171,650,856)	(123,535,673)	(1,774,096)	(43,533,325)	(2,807,763)	-	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	(143,656,900)	(81,211,077)	(1,685,004)	(55,989,505)	(3,801,721)	-	-		(969,592)
Total	(315,307,756)	(204,746,750)	(3,459,100)	(99,522,830)	(6,609,484)	-	-		(969,592)
(108-369) Services	(191,180,068)								
- Demand	(95,590,034)	(68,795,341)	(987,970)	(24,243,119)	(1,563,605)	-	-		-
- Customer	(95,590,034)	(83,599,311)	(1,183,186)	(10,791,924)	(15,613)	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	(191,180,068)	(152,394,652)	(2,171,156)	(35,035,043)	(1,579,218)	-	-		-
(108-370) Meters	(67,885,351)								
- Demand	(30,205,744)	(13,736,522)	(1,463,393)	(14,868,904)	(136,925)	-	-		-
- Customer	(37,679,606)	(28,764,128)	(386,508)	(3,614,272)	(79,723)	(2,440,656)	(2,368,485)		-
- Commodity	-	-	-	-	-	-	-		-
Total	(67,885,351)	(42,500,650)	(1,849,901)	(18,483,176)	(216,648)	(2,440,656)	(2,368,485)		-
(108-371) Install on Cust Premise	(10,069,793)								
- Demand	(10,069,793)	-	-	-	-	-	-		(10,069,793)
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	(10,069,793)	-	-	-	-	-	-		(10,069,793)
(108-373) St Lt & Signal Sys	(99,523,237)								
- Demand	(99,523,237)	-	-	-	-	-	-		(99,523,237)
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	(99,523,237)	-	-	-	-	-	-		(99,523,237)

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Total System	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
(108-374) Asset Ret Costs	-								
- Demand	-	-	-	-	-	-	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	-	-	-	-	-	-	-		-
(108-389) Land & Land Rights	(7,224)								
- Demand	(3,741)	(2,380)	(34)	(839)	(54)	(191)	(217)		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	(3,484)	(1,645)	(34)	(1,134)	(77)	(264)	(277)		(20)
Total	(7,224)	(4,025)	(68)	(1,973)	(131)	(455)	(493)		(20)
(108-390) Struct & Impmnts -	(58,687,376)								
- Demand	(30,387,534)	(19,333,285)	(277,645)	(6,812,948)	(439,414)	(1,552,533)	(1,759,004)		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	(28,299,842)	(13,362,542)	(277,252)	(9,212,562)	(625,539)	(2,146,418)	(2,248,068)		(159,537)
Total	(58,687,376)	(32,695,827)	(554,897)	(16,025,511)	(1,064,952)	(3,698,951)	(4,007,072)		(159,537)
(108-391) Office Furn & Equip	(6,552,210)								
- Demand	(3,392,646)	(2,158,484)	(30,998)	(760,638)	(49,059)	(173,334)	(196,386)		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	(3,159,564)	(1,491,874)	(30,954)	(1,028,546)	(69,839)	(239,639)	(250,988)		(17,812)
Total	(6,552,210)	(3,650,358)	(61,952)	(1,789,184)	(118,898)	(412,973)	(447,373)		(17,812)
(108-392) Transportation Equip	(5,404,888)								
- Demand	(2,798,578)	(1,780,523)	(25,570)	(627,447)	(40,468)	(142,983)	(161,998)		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	(2,606,310)	(1,230,640)	(25,534)	(848,443)	(57,610)	(197,677)	(207,039)		(14,693)
Total	(5,404,888)	(3,011,163)	(51,104)	(1,475,890)	(98,078)	(340,660)	(369,036)		(14,693)
(108-393) Stores Equip	(1,001,584)								
- Demand	(518,607)	(329,950)	(4,738)	(116,273)	(7,499)	(26,496)	(30,020)		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	(482,977)	(228,051)	(4,732)	(157,226)	(10,676)	(36,632)	(38,366)		(2,723)
Total	(1,001,584)	(558,001)	(9,470)	(273,498)	(18,175)	(63,128)	(68,386)		(2,723)
(108-394) Tools, Shop & Garage Equip	(11,197,840)								
- Demand	(5,798,091)	(3,688,886)	(52,976)	(1,299,944)	(83,842)	(296,231)	(335,627)		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	(5,399,749)	(2,549,639)	(52,901)	(1,757,802)	(119,356)	(409,547)	(428,942)		(30,441)
Total	(11,197,840)	(6,238,525)	(105,877)	(3,057,746)	(203,198)	(705,778)	(764,569)		(30,441)
(108-395) Laboratory Equip	(437,931)								
- Demand	(226,755)	(144,267)	(2,072)	(50,839)	(3,279)	(11,585)	(13,126)		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	(211,176)	(99,713)	(2,069)	(68,745)	(4,668)	(16,017)	(16,775)		(1,190)
Total	(437,931)	(243,980)	(4,141)	(119,584)	(7,947)	(27,602)	(29,901)		(1,190)
(108-396) Power Operated Equip	(1,256,882)								
- Demand	(650,797)	(414,053)	(5,946)	(145,910)	(9,411)	(33,250)	(37,672)		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	(606,086)	(286,180)	(5,938)	(197,301)	(13,397)	(45,969)	(48,146)		(3,417)
Total	(1,256,882)	(700,232)	(11,884)	(343,211)	(22,808)	(79,219)	(85,818)		(3,417)
(108-397) Communication Equip	(13,697,169)								
- Demand	(7,092,210)	(4,512,236)	(64,800)	(1,590,088)	(102,556)	(362,349)	(410,538)		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	(6,604,959)	(3,118,712)	(64,708)	(2,150,139)	(145,996)	(500,957)	(524,681)		(37,235)
Total	(13,697,169)	(7,630,947)	(129,509)	(3,740,227)	(248,551)	(863,306)	(935,219)		(37,235)
(108-398) MISC Equip	(224,207)								
- Demand	(116,091)	(73,860)	(1,061)	(26,028)	(1,679)	(5,931)	(6,720)		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	(108,116)	(51,050)	(1,059)	(35,195)	(2,390)	(8,200)	(8,588)		(609)
Total	(224,207)	(124,910)	(2,120)	(61,223)	(4,069)	(14,131)	(15,308)		(609)
(108-399) Other Tangible Property	-								
- Demand	-	-	-	-	-	-	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	-	-	-	-	-	-	-		-
Service Company PIS	(89,349,869)								
- Demand	(46,264,160)	(29,434,379)	(422,707)	(10,372,521)	(668,995)	(2,363,688)	(2,678,034)		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	(43,085,709)	(20,344,092)	(422,108)	(14,025,866)	(952,365)	(3,267,860)	(3,422,620)		(242,891)
Total	(89,349,869)	(49,778,471)	(844,816)	(24,398,387)	(1,621,360)	(5,631,548)	(6,100,654)		(242,891)
Total Accumulated Depreciation	(2,023,407,484)								
- Demand	(1,120,414,629)	(695,023,191)	(11,247,352)	(254,950,765)	(15,621,450)	(23,759,467)	(9,116,928)		(109,593,030)
- Customer	(133,269,640)	(112,363,439)	(1,569,693)	(14,406,197)	(95,336)	(2,440,656)	(2,368,485)		-
- Commodity	(769,723,215)	(409,479,909)	(8,496,075)	(282,308,499)	(19,168,919)	(32,340,569)	(11,651,747)		(4,888,845)
Total Accumulated Depreciation	**(2,023,407,484)**	**(1,216,866,538)**	**(21,313,120)**	**(551,665,461)**	**(34,885,705)**	**(58,540,692)**	**(23,137,160)**		**(114,481,875)**

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Total System	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
OTHER RATE BASE ITEMS									
Other Rate Base Items									
Materials and Supplies	26,179,976								
- Demand	14,644,327	9,077,543	150,780	3,360,593	203,491	256,373	-		1,595,547
- Customer	1,734,752	1,449,595	20,184	185,535	1,470	39,358	38,194		-
- Commodity	9,800,897	5,344,882	110,898	3,684,932	250,209	346,162	-		63,813
Total	26,179,976	15,872,020	281,862	7,231,060	455,170	641,893	38,194		1,659,360
Cash Working Capital	107,271,360								
- Demand	56,480,532	34,949,791	912,778	15,570,344	737,471	1,260,688	-		3,049,460
- Customer	12,713,356	9,759,254	131,441	1,227,732	25,950	792,008	768,588		-
- Commodity	38,077,472	20,738,676	428,396	14,005,498	942,675	1,710,983	8,394		241,959
Total	107,271,360	65,447,721	1,472,615	30,803,574	1,706,096	3,763,679	776,982		3,291,418
ADIT	(1,196,729,137)								
- Demand	(669,415,941)	(414,949,187)	(6,892,401)	(153,618,175)	(9,301,903)	(11,719,240)	-		(72,935,035)
- Customer	(79,298,324)	(66,263,331)	(922,649)	(8,481,086)	(67,183)	(1,799,116)	(1,745,916)		-
- Commodity	(448,014,872)	(244,323,221)	(5,069,329)	(168,444,215)	(11,437,465)	(15,823,629)	-		(2,917,013)
Total	(1,196,729,137)	(725,535,739)	(12,884,379)	(330,543,476)	(20,806,550)	(29,341,985)	(1,745,916)		(75,852,048)
Net /Loss on Reacq Debt	1,371,332								
- Demand	767,084	475,490	7,898	176,031	10,659	13,429	-		83,576
- Customer	90,868	75,931	1,057	9,718	77	2,062	2,001		-
- Commodity	513,380	279,970	5,809	193,020	13,106	18,132	-		3,343
Total	1,371,332	831,391	14,764	378,770	23,842	33,623	2,001		86,919
DTA for AMT	9,517,218								
- Demand	5,323,659	3,299,963	54,813	1,221,678	73,975	93,200	-		580,030
- Customer	630,635	526,972	7,338	67,447	534	14,308	13,885		-
- Commodity	3,562,924	1,943,027	40,315	1,339,585	90,959	125,840	-		23,198
Total	9,517,218	5,769,962	102,465	2,628,710	165,468	233,348	13,885		603,228
Net Operating Reserves	(9,351,760)								
- Demand	(4,987,593)	(3,376,131)	(57,743)	(1,263,064)	(75,452)	(146,484)	-		(68,719)
- Customer	(326,634)	(252,056)	(3,417)	(31,815)	(591)	(17,848)	(20,719)		-
- Commodity	(4,037,533)	(2,174,608)	(45,077)	(1,492,655)	(101,165)	(197,984)	(189)		(25,836)
Total	(9,351,760)	(5,802,794)	(106,237)	(2,787,533)	(177,208)	(362,316)	(20,909)		(94,554)
NOL	36,093,727								
- Demand	20,189,795	12,514,998	207,877	4,633,172	280,548	353,456	-		2,199,744
- Customer	2,391,662	1,998,523	27,827	255,792	2,026	54,262	52,657		-
- Commodity	13,512,269	7,368,865	152,893	5,080,330	344,958	477,246	-		87,978
Total	36,093,727	21,882,386	388,597	9,969,295	627,532	884,963	52,657		2,287,722
CTA	(964,275)								
- Demand	(532,909)	(336,214)	(5,423)	(123,192)	(7,559)	(10,949)	(2,752)		(46,487)
- Customer	(56,197)	(47,179)	(658)	(6,044)	(44)	(1,147)	(1,113)		-
- Commodity	(375,170)	(201,461)	(4,180)	(138,894)	(9,431)	(14,862)	(3,518)		(2,405)
Total	(964,275)	(584,854)	(10,261)	(268,129)	(17,034)	(26,957)	(7,383)		(48,892)
Regulatory Asset A&G Capitalization	54,917,355								
- Demand	29,078,140	19,783,903	284,117	6,971,744	449,656	1,588,720	-		-
- Customer	70,811	-	-	-	-	-	70,811		-
- Commodity	25,768,404	13,354,537	277,086	9,207,043	625,164	2,145,132	-		159,442
Total	54,917,355	33,138,441	561,203	16,178,788	1,074,819	3,733,851	70,811		159,442
Customer Deposits	(36,962,658)								
- Demand	-	-	-	-	-	-	-		-
- Customer	(36,962,658)	(32,304,391)	(457,206)	(4,170,208)	(6,033)	(19,249)	(5,538)		-
- Commodity	-	-	-	-	-	-	-		-
Total	(36,962,658)	(32,304,391)	(457,206)	(4,170,208)	(6,033)	(19,249)	(5,538)		-
Customer Advances	(49,827,476)								
- Demand	(27,872,060)	(17,276,984)	(286,975)	(6,396,106)	(387,298)	(487,947)	-		(3,036,751)
- Customer	(3,301,696)	(2,758,966)	(38,416)	(353,122)	(2,797)	(74,909)	(72,694)		-
- Commodity	(18,653,720)	(10,172,736)	(211,069)	(7,013,408)	(476,215)	(658,839)	-		(121,454)
Total	(49,827,476)	(30,208,686)	(536,459)	(13,762,636)	(866,310)	(1,221,694)	(72,694)		(3,158,205)
Customer Refunds	(278,071)								
- Demand	(155,545)	(96,417)	(1,602)	(35,695)	(2,161)	(2,723)	-		(16,947)
- Customer	(18,426)	(15,397)	(214)	(1,971)	(16)	(418)	(406)		-
- Commodity	(104,100)	(56,771)	(1,178)	(39,140)	(2,658)	(3,677)	-		(678)
Total	(278,071)	(168,585)	(2,994)	(76,805)	(4,835)	(6,818)	(406)		(17,625)
Total Other Rate Base Items	(1,058,762,409)								
- Demand	(576,480,511)	(355,933,245)	(5,625,881)	(129,502,668)	(8,018,574)	(8,801,476)	(2,752)		(68,595,582)
- Customer	(102,331,850)	(87,831,046)	(1,234,713)	(11,298,021)	(46,606)	(1,010,689)	(900,250)		-
- Commodity	(379,950,048)	(207,898,838)	(4,315,436)	(143,617,902)	(9,759,863)	(11,875,495)	4,687		(2,487,654)
Total	(1,058,762,409)	(651,663,129)	(11,176,029)	(284,418,590)	(17,825,042)	(21,687,661)	(898,315)		(71,083,236)

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Total System	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
Rate Base Adjustment									
Adjustment									
AMI	43,720,862								
- Demand	19,453,699	8,846,866	942,483	9,576,165	88,185	-	-		-
- Customer	24,267,163	18,525,240	248,926	2,327,735	51,345	1,571,879	1,525,399		-
- Commodity	-	-	-	-	-	-	-		-
Total	43,720,862	27,372,106	1,191,409	11,903,900	139,530	1,571,879	1,525,399		-
Delayed Recognition Pension & OPEB	(36,089,750)								
- Demand	(19,031,473)	(12,100,432)	(273,956)	(5,057,609)	(261,154)	(594,768)	-		(743,554)
- Customer	(3,112,722)	(2,379,611)	(32,049)	(299,360)	(6,327)	(193,116)	(200,214)		-
- Commodity	(13,945,555)	(7,472,352)	(154,577)	(5,080,380)	(342,935)	(805,210)	(2,047)		(87,837)
Total	(36,089,750)	(21,952,395)	(460,582)	(10,437,349)	(610,416)	(1,593,095)	(202,261)		(831,391)
Total Rate Base Adjustment	7,631,112								
- Demand	422,226	(3,253,566)	668,527	4,518,555	(172,968)	(594,768)	-		(743,554)
- Customer	21,154,441	16,145,629	216,877	2,028,375	45,017	1,378,763	1,325,184		-
- Commodity	(13,945,555)	(7,472,352)	(154,577)	(5,080,380)	(342,935)	(805,210)	(2,047)		(87,837)
Total	7,631,112	5,419,711	730,828	1,466,551	(470,886)	(21,215)	1,323,138		(831,391)
Total Rate Base	**2,987,495,271**								
- Demand	**1,653,723,168**	**1,059,438,732**	**17,889,138**	**394,524,131**	**23,709,033**	**35,674,914**	**8,184,052**		**113,313,529**
- Customer	**138,841,265**	**112,550,359**	**1,549,432**	**14,320,290**	**178,078**	**5,136,353**	**5,052,215**		**-**
- Commodity	**1,194,930,837**	**641,658,079**	**13,312,019**	**442,165,010**	**30,017,179**	**48,408,961**	**10,465,658**		**7,656,716**
Total	**2,987,495,271**	**1,813,647,170**	**32,750,589**	**851,009,430**	**53,904,290**	**89,220,227**	**23,701,925**		**120,970,245**
OPERATIONS & MAINTENANCE EXPENSES									
Distribution Expenses									
Operations Expenses									
(580) Operation Supervision & Engineering	392,311								
- Demand	211,283	148,704	2,136	52,403	3,380	4,661	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	181,028	98,780	2,050	68,102	4,624	6,293	-		1,179
Total	392,311	247,484	4,185	120,505	8,004	10,954	-		1,179
(581) Load Dispatching	1,446,055								
- Demand	766,659	521,612	7,491	183,813	11,855	41,887	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	679,396	352,099	7,306	242,748	16,483	56,557	-		4,204
Total	1,446,055	873,711	14,796	426,561	28,338	98,445	-		4,204
(582) Station Expenses	609,126								
- Demand	327,272	229,186	3,291	80,764	5,209	8,822	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	281,854	152,601	3,166	105,208	7,144	11,912	-		1,822
Total	609,126	381,787	6,458	185,972	12,353	20,734	-		1,822
(583) Overhead line expenses	1,040,054								
- Demand	558,802	391,324	5,620	137,901	8,894	15,063	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	481,252	260,560	5,406	179,638	12,198	20,339	-		3,111
Total	1,040,054	651,884	11,026	317,539	21,092	35,402	-		3,111
(584) Underground line expenses	3,974,417								
- Demand	2,135,383	1,495,390	21,475	526,968	33,988	57,563	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	1,839,034	995,692	20,659	686,462	46,611	77,723	-		11,888
Total	3,974,417	2,491,081	42,134	1,213,429	80,599	135,285	-		11,888
(585) Street lighting and signal system expenses	-								
- Demand	-	-	-	-	-	-	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	-	-	-	-	-	-	-		-
(586) Meter expenses	3,863,627								
- Demand	1,719,130	781,801	83,288	846,249	7,793	-	-		-
- Customer	2,144,497	1,637,082	21,998	205,703	4,537	138,908	134,800		-
- Commodity	-	-	-	-	-	-	-		-
Total	3,863,627	2,418,882	105,285	1,051,952	12,330	138,908	134,800		-
(587) Customer installations expenses	-								
- Demand	-	-	-	-	-	-	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	-	-	-	-	-	-	-		-
(588) Miscellaneous distribution expenses	22,995,565								
- Demand	12,800,845	7,959,432	130,868	2,936,046	178,612	301,572	-		1,294,315
- Customer	1,293,819	1,076,726	14,970	137,702	1,174	31,927	30,983		-
- Commodity	8,900,901	4,801,603	99,626	3,310,378	224,777	407,191	-		57,327
Total	22,995,565	13,837,760	245,464	6,384,125	404,562	740,690	30,983		1,351,642
(589) Rents	3,791,923								
- Demand	2,042,177	1,437,315	20,641	506,502	32,668	45,050	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	1,749,746	954,767	19,810	658,247	44,695	60,828	-		11,399
Total	3,791,923	2,392,082	40,451	1,164,749	77,363	105,878	-		11,399
Total Dist. Operations Expenses	38,113,078								
- Demand	20,561,551	12,964,764	274,810	5,270,645	282,399	474,619	-		1,294,315
- Customer	3,438,316	2,713,807	36,967	343,404	5,711	170,835	165,783		-
- Commodity	14,113,210	7,616,101	158,022	5,250,783	356,531	640,843	-		90,930
Total	38,113,078	23,294,672	469,799	10,864,832	644,641	1,286,297	165,783		1,385,245
Maintenance Expense									
(590) Maintenance Supervision and Engineering	3,029,283								
- Demand	1,631,450	1,148,239	16,490	404,633	26,098	35,990	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	1,397,833	762,742	15,826	525,859	35,706	48,594	-		9,106
Total	3,029,283	1,910,981	32,316	930,492	61,804	84,584	-		9,106

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Total System	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
(591) Maintenance of Structures	50,499								
- Demand	26,773	18,216	262	6,419	414	1,463	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	23,726	12,296	255	8,477	576	1,975	-		147
Total	50,499	30,512	517	14,896	990	3,438	-		147
(592) Maintenance of Station Equipment	11,973,912								
- Demand	6,433,368	4,505,231	64,700	1,587,620	102,396	173,422	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	5,540,544	2,999,767	62,241	2,068,135	140,428	234,159	-		35,815
Total	11,973,912	7,504,998	126,940	3,655,755	242,824	407,581	-		35,815
(593) Maintenance of Overhead Lines	84,228,604								
- Demand	45,254,520	31,691,337	455,119	11,167,862	720,292	1,219,910	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	38,974,084	21,101,389	437,821	14,547,970	987,816	1,647,154	-		251,933
Total	84,228,604	52,792,727	892,941	25,715,832	1,708,108	2,867,064	-		251,933
(594) Maintenance of underground lines	4,572,747								
- Demand	2,456,855	1,720,514	24,708	606,300	39,104	66,229	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	2,115,892	1,145,588	23,769	789,805	53,628	89,424	-		13,677
Total	4,572,747	2,866,102	48,477	1,396,105	92,733	155,652	-		13,677
(595) Maintenance of line transformers	151,393								
- Demand	151,393	108,956	1,565	38,396	2,476	-	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	151,393	108,956	1,565	38,396	2,476	-	-		-
(596) Maintenance of street lighting and signal systems	4,146,141								
- Demand	4,146,141	-	-	-	-	-	-		4,146,141
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	4,146,141	-	-	-	-	-	-		4,146,141
(597) Maintenance of meters	4,075,777								
- Demand	1,813,526	824,729	87,861	892,716	8,221	-	-		-
- Customer	2,262,251	1,726,973	23,206	216,998	4,787	146,535	142,202		-
- Commodity	-	-	-	-	-	-	-		-
Total	4,075,777	2,551,702	111,066	1,109,714	13,007	146,535	142,202		-
(598) Maintenance of miscellaneous distribution plant	2,564,666								
- Demand	1,427,662	887,705	14,596	327,453	19,920	33,634	-		144,353
- Customer	144,298	120,086	1,670	15,358	131	3,561	3,456		-
- Commodity	992,706	535,517	11,111	369,202	25,069	45,413	-		6,394
Total	2,564,666	1,543,308	27,376	712,013	45,120	82,608	3,456		150,747
Total Dist. Maintenance Expenses	114,793,021								
- Demand	63,341,688	40,904,927	665,300	15,031,399	918,922	1,530,646	-		4,290,494
- Customer	2,406,549	1,847,059	24,875	232,355	4,917	150,096	145,657		-
- Commodity	49,044,784	26,557,299	551,023	18,309,448	1,243,223	2,066,719	-		317,072
Total	114,793,021	69,309,285	1,241,198	33,573,203	2,167,062	3,747,462	145,657		4,607,566
Total Distribution Expenses	152,906,099								
- Demand	83,903,240	53,869,690	940,110	20,302,044	1,201,321	2,005,265	-		5,584,810
- Customer	5,844,865	4,560,866	61,842	575,760	10,628	320,931	311,441		-
- Commodity	63,157,994	34,173,400	709,045	23,560,231	1,599,754	2,707,562	-		408,002
Total	152,906,099	92,603,956	1,710,997	44,438,035	2,811,703	5,033,758	311,441		5,992,811
Customer Account Expense									
(901) Supervision	42,924								
- Demand	-	-	-	-	-	-	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	42,924	34,023	605	7,950	99	89	51		107
Total	42,924	34,023	605	7,950	99	89	51		107
(902) Meter reading expenses	15,227,521								
- Demand	6,775,521	3,081,271	328,257	3,335,278	30,714	-	-		-
- Customer	8,452,000	6,452,148	86,698	810,726	17,883	547,469	531,280		-
- Commodity	-	-	-	-	-	-	-		-
Total	15,227,521	9,533,420	414,956	4,146,004	48,597	547,469	531,280		-
(903) Customer records and collection expenses	16,190,497								
- Demand	7,203,999	3,276,128	349,016	3,546,199	32,656	-	-		-
- Customer	8,986,498	6,860,177	92,181	861,995	19,014	582,091	564,878		-
- Commodity	-	-	-	-	-	-	-		-
Total	16,190,497	10,136,305	441,197	4,408,194	51,670	582,091	564,878		-
(904) Uncollectible accounts	171,298								
- Demand	-	-	-	-	-	-	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	171,298	80,883	1,678	55,763	3,786	12,992	13,607		966
Total	171,298	80,883	1,678	55,763	3,786	12,992	13,607		966
(905) Miscellaneous customer accounts expenses	1,439,425								
- Demand	-	-	-	-	-	-	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	1,439,425	1,140,931	20,295	266,584	3,328	2,978	1,715		3,585
Total	1,439,425	1,140,931	20,295	266,584	3,328	2,978	1,715		3,585
Total Customer Account Expenses	33,071,665								
- Demand	13,979,520	6,357,400	677,273	6,881,477	63,370	-	-		-
- Customer	17,438,498	13,312,325	178,880	1,672,721	36,897	1,129,560	1,096,159		-
- Commodity	1,653,647	1,255,836	22,578	330,297	7,214	16,059	15,373		4,658
Total	33,071,665	20,925,562	878,730	8,884,495	107,481	1,145,619	1,111,532		4,658

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Total System	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
Customer Service Expenses									
(907) Customer Service Supervision	46,097								
- Demand	24,439	16,628	239	5,860	378	1,335	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	21,658	11,224	233	7,738	525	1,803	-		134
Total	46,097	27,852	472	13,598	903	3,138	-		134
(908) Customer Assistance	2,080,009								
- Demand	1,102,764	750,288	10,775	264,398	17,053	60,251	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	977,245	506,460	10,508	349,169	23,709	81,352	-		6,047
Total	2,080,009	1,256,748	21,283	613,567	40,762	141,603	-		6,047
(909) Informational and instructional advertising	2,645								
- Demand	1,402	954	14	336	22	77	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	1,243	644	13	444	30	103	-		8
Total	2,645	1,598	27	780	52	180	-		8
(910) Miscellaneous customer service and informational	8,351,286								
- Demand	4,427,624	3,012,424	43,261	1,061,562	68,467	241,909	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	3,923,662	2,033,447	42,191	1,401,923	95,191	326,631	-		24,278
Total	8,351,286	5,045,871	85,452	2,463,486	163,659	568,540	-		24,278
Total Customer Service Expenses	10,480,037								
- Demand	5,556,229	3,780,294	54,289	1,332,156	85,920	303,571	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	4,923,808	2,551,775	52,945	1,759,275	119,456	409,890	-		30,466
Total	10,480,037	6,332,069	107,234	3,091,431	205,376	713,462	-		30,466
Sales Expenses									
(911) Sales Exp	4								
- Demand	2	1	0	1	0	0	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	2	1	0	1	0	0	-		0
Total	4	2	0	1	0	0	-		0
Total Sales Expenses	4								
- Demand	2	1	0	1	0	0	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	2	1	0	1	0	0	-		0
Total	4	2	0	1	0	0	-		0
Administrative & General Expense									
Labor Related									
(920) Administrative and general salaries	13,475,844								
- Demand	7,135,312	4,854,655	69,718	1,710,755	110,338	389,847	-		-
- Customer	17,376	-	-	-	-	-	17,376		-
- Commodity	6,323,156	3,276,991	67,992	2,259,262	153,405	526,381	-		39,125
Total	13,475,844	8,131,645	137,710	3,970,017	263,744	916,228	17,376		39,125
(921) Office supplies and expenses	1,205,430								
- Demand	638,262	434,255	6,236	153,029	9,870	34,872	-		-
- Customer	1,554	-	-	-	-	-	1,554		-
- Commodity	565,614	293,131	6,082	202,094	13,722	47,085	-		3,500
Total	1,205,430	727,385	12,318	355,123	23,592	81,958	1,554		3,500
(922) Administrative expenses transferred—Credit	(1,200,145)								
- Demand	(635,464)	(432,351)	(6,209)	(152,358)	(9,827)	(34,719)	-		-
- Customer	(1,547)	-	-	-	-	-	(1,547)		-
- Commodity	(563,134)	(291,845)	(6,055)	(201,208)	(13,662)	(46,879)	-		(3,484)
Total	(1,200,145)	(724,196)	(12,264)	(353,566)	(23,489)	(81,598)	(1,547)		(3,484)
(923) Outside services employed	43,893,380								
- Demand	23,241,065	15,812,531	227,084	5,572,253	359,393	1,269,804	-		-
- Customer	56,597	-	-	-	-	-	56,597		-
- Commodity	20,595,718	10,673,780	221,464	7,358,844	499,670	1,714,523	-		127,436
Total	43,893,380	26,486,311	448,548	12,931,098	859,063	2,984,327	56,597		127,436
(926) Employee pensions and benefits	(2,710,024)								
- Demand	(1,434,928)	(976,283)	(14,020)	(344,037)	(22,189)	(78,399)	-		-
- Customer	(3,494)	-	-	-	-	-	(3,494)		-
- Commodity	(1,271,602)	(659,011)	(13,673)	(454,343)	(30,850)	(105,856)	-		(7,868)
Total	(2,710,024)	(1,635,293)	(27,694)	(798,380)	(53,039)	(184,256)	(3,494)		(7,868)
(426) Pension / OPEB Non-Service Cost	-								
- Demand	-	-	-	-	-	-	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	-	-	-	-	-	-	-		-
(924) Property insurance	275,013								
- Demand	145,616	99,073	1,423	34,913	2,252	7,956	-		-
- Customer	355	-	-	-	-	-	355		-
- Commodity	129,042	66,876	1,388	46,107	3,131	10,742	-		798
Total	275,013	165,949	2,810	81,020	5,382	18,698	355		798
(925) Injuries and damages	5,022,788								
- Demand	2,659,511	1,809,453	25,986	637,642	41,126	145,306	-		-
- Customer	6,476	-	-	-	-	-	6,476		-
- Commodity	2,356,800	1,221,417	25,343	842,084	57,178	196,196	-		14,583
Total	5,022,788	3,030,870	51,328	1,479,726	98,304	341,501	6,476		14,583
(935) Maintenance of general plant	4,492,676								
- Demand	2,378,823	1,618,481	23,243	570,344	36,785	129,970	-		-
- Customer	5,793	-	-	-	-	-	5,793		-
- Commodity	2,108,060	1,092,507	22,668	753,209	51,143	175,489	-		13,044
Total	4,492,676	2,710,988	45,911	1,323,553	87,929	305,459	5,793		13,044

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Total System	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG
(929) Duplicate charges—Credit	-								
- Demand	-	-	-	-	-	-	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	-	-	-	-	-	-	-		-
(928) Regulatory commission expenses	4,819,478								
- Demand	2,551,861	1,736,210	24,934	611,832	39,461	139,424	-		-
- Customer	6,214	-	-	-	-	-	6,214		-
- Commodity	2,261,403	1,171,977	24,317	807,999	54,864	188,254	-		13,992
Total	4,819,478	2,908,188	49,250	1,419,830	94,325	327,678	6,214		13,992
(930.1) Gen Advertising Exp	773,089								
- Demand	409,342	278,504	4,000	98,143	6,330	22,365	-		-
- Customer	997	-	-	-	-	-	997		-
- Commodity	362,750	187,996	3,901	129,610	8,801	30,198	-		2,245
Total	773,089	466,500	7,900	227,754	15,131	52,563	997		2,245
(930.2) Misc Gen Exp	2,420,568								
- Demand	1,281,664	872,006	12,523	307,290	19,819	70,025	-		-
- Customer	3,121	-	-	-	-	-	3,121		-
- Commodity	1,135,783	588,622	12,213	405,815	27,555	94,550	-		7,028
Total	2,420,568	1,460,628	24,736	713,105	47,374	164,575	3,121		7,028
(931) Rents	2,143,204								
- Demand	1,134,803	772,086	11,088	272,079	17,548	62,001	-		-
- Customer	2,763	-	-	-	-	-	2,763		-
- Commodity	1,005,637	521,174	10,814	359,314	24,398	83,716	-		6,222
Total	2,143,204	1,293,260	21,901	631,393	41,946	145,717	2,763		6,222
(932) Institutional Ad - Newspaper	-								
- Demand	-	-	-	-	-	-	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	-	-	-	-	-	-	-		-
(933) Transportation expenses	-								
- Demand	-	-	-	-	-	-	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
	-	-	-	-	-	-	-		-
Total A&G Expense	74,611,301								
- Demand	39,505,869	26,878,621	386,004	9,471,886	610,907	2,158,452	-		-
- Customer	96,205	-	-	-	-	-	96,205		-
- Commodity	35,009,227	18,143,616	376,452	12,508,787	849,354	2,914,399	-		216,619
Total	74,611,301	45,022,237	762,456	21,980,673	1,460,261	5,072,850	96,205		216,619
O&M Adjustment									
Adjustment									
Int on Cust Deposits	517,477								
- Demand	-	-	-	-	-	-	-		-
- Customer	517,477	452,261	6,401	58,383	84	269	78		-
- Commodity	-	-	-	-	-	-	-		-
Total	517,477	452,261	6,401	58,383	84	269	78		-
Annualize Payroll Increase	5,227,469								
- Demand	2,756,640	1,752,704	39,682	732,576	37,827	86,150	-		107,701
- Customer	450,866	344,678	4,642	43,361	917	27,972	29,000		-
- Commodity	2,019,963	1,082,343	22,390	735,875	49,673	116,632	296		12,723
Total	5,227,469	3,179,725	66,714	1,511,812	88,417	230,754	29,297		120,424
Svngs Pln Match on Payroll Inc	156,824								
- Demand	82,699	52,581	1,190	21,977	1,135	2,584	-		3,231
- Customer	13,526	10,340	139	1,301	27	839	870		-
- Commodity	60,599	32,470	672	22,076	1,490	3,499	9		382
Total	156,824	95,392	2,001	45,354	2,652	6,923	879		3,613
Reclass Amortization of Net Loss on Reacquired Debt	619,772								
- Demand	344,793	217,351	3,544	79,940	4,882	6,052	-		33,024
- Customer	39,922	33,516	467	4,294	31	815	791		-
- Commodity	235,058	128,262	2,661	88,428	6,004	8,172	-		1,531
Total	619,772	379,128	6,673	172,662	10,917	15,038	791		34,555
BPU & RPA Assessments	843,045								
- Demand	222,640	-	-	143,863	11,348	27,994	20,802		18,233
- Customer	67,883	48,417	1,477	16,625	141	545	674		-
- Commodity	552,523	410,383	7,591	112,086	2,796	7,197	5,447		7,023
Total	843,045	458,800	9,068	272,575	14,284	35,736	26,923		25,257
Rate Case Exp	-								
- Demand	-	-	-	-	-	-	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	-	-	-	-	-	-	-		-
Pension Smoothing	14,294,389								
- Demand	7,537,965	4,792,726	108,508	2,003,212	103,437	235,575	-		294,506
- Customer	1,232,884	942,514	12,694	118,570	2,506	76,489	79,301		-
- Commodity	5,523,540	2,959,641	61,225	2,012,231	135,829	318,927	811		34,791
Total	14,294,389	8,694,881	182,427	4,134,014	241,773	630,991	80,111		329,296
OPEB Smoothing	4,904,994								
- Demand	2,586,586	1,644,582	37,234	687,385	35,494	80,836	-		101,057
- Customer	423,053	323,415	4,356	40,686	860	26,247	27,211		-
- Commodity	1,895,354	1,015,575	21,009	690,479	46,609	109,437	278		11,938
Total	4,904,994	2,983,572	62,598	1,418,550	82,962	216,519	27,490		112,995

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Total System	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	Lighting LTG
Normalize Vegetation Management Expense	8,276,658							
- Demand	4,446,900	3,114,125	44,722	1,097,401	70,779	119,873	-	-
- Customer	-	-	-	-	-	-	-	-
- Commodity	3,829,758	2,073,512	43,022	1,429,545	97,067	161,856	-	24,756
Total	8,276,658	5,187,636	87,744	2,526,946	167,846	281,730	-	24,756
ServCo Depr @ JCP&L Rates	1,872,457							
- Demand	969,533	616,840	8,858	217,371	14,020	49,535	56,122	-
- Customer	-	-	-	-	-	-	-	-
- Commodity	902,924	426,340	8,846	293,932	19,958	68,483	71,726	5,090
Total	1,872,457	1,043,181	17,704	511,304	33,978	118,017	127,848	5,090
SERP/EDCP	4,921,662							
- Demand	2,595,376	1,650,170	37,360	689,721	35,614	81,110	-	101,401
- Customer	424,491	324,514	4,371	40,825	863	26,336	27,304	-
- Commodity	1,901,795	1,019,026	21,080	692,826	46,767	109,809	279	11,979
Total	4,921,662	2,993,711	62,811	1,423,371	83,244	217,255	27,583	113,379
Advertising removal	(746,134)							
- Demand	(395,070)	(268,794)	(3,860)	(94,722)	(6,109)	(21,585)	-	-
- Customer	(962)	-	-	-	-	-	(962)	-
- Commodity	(350,102)	(181,441)	(3,765)	(125,091)	(8,494)	(29,145)	-	(2,166)
Total	(746,134)	(450,235)	(7,625)	(219,813)	(14,603)	(50,730)	(962)	(2,166)
BGS Administrative Labor included in BGS Deferral	637,271							
- Demand	329,970	209,935	3,015	73,980	4,771	16,859	19,101	-
- Customer	-	-	-	-	-	-	-	-
- Commodity	307,301	145,100	3,011	100,037	6,793	23,307	24,411	1,732
Total	637,271	355,035	6,025	174,017	11,564	40,166	43,512	1,732
Low Income O&M	1,764,122							
- Demand	913,439	581,152	8,346	204,795	13,209	46,669	52,875	-
- Customer	-	-	-	-	-	-	-	-
- Commodity	850,684	401,673	8,334	276,926	18,803	64,521	67,576	4,796
Total	1,764,122	982,825	16,680	481,721	32,012	111,189	120,451	4,796
Contract Labor/Fuel Costs	81,460							
- Demand	43,132	29,346	421	10,341	667	2,357	-	-
- Customer	105	-	-	-	-	-	105	-
- Commodity	38,223	19,809	411	13,657	927	3,182	-	237
Total	81,460	49,155	832	23,998	1,594	5,538	105	237
Total O&M Adjustment	43,371,467							
- Demand	22,434,603	14,392,718	289,020	5,867,842	327,073	734,008	148,900	659,153
- Customer	3,169,244	2,479,656	34,548	324,045	5,429	159,512	164,371	-
- Commodity	17,767,619	9,532,693	196,486	6,343,008	424,223	965,876	170,833	114,811
Total	43,371,467	26,405,066	520,054	12,534,894	756,725	1,859,396	484,104	773,964
Total O&M Expenses	314,440,573							
- Demand	165,379,464	105,278,724	2,346,695	43,855,406	2,288,591	5,201,296	148,900	6,243,962
- Customer	26,548,812	20,352,847	275,270	2,572,526	52,954	1,610,003	1,668,175	-
- Commodity	122,512,297	65,657,321	1,357,506	44,501,598	3,000,001	7,013,786	186,207	774,556
Total	**314,440,573**	**191,288,892**	**3,979,472**	**90,929,530**	**5,341,546**	**13,825,085**	**2,003,282**	**7,018,518**
DEPRECIATION EXPENSE								
Depreciation Expense								
(403-360) Land & Land Rights	133,315							
- Demand	71,628	50,160	720	17,676	1,140	1,931	-	-
- Customer	-	-	-	-	-	-	-	-
- Commodity	61,687	33,399	693	23,026	1,563	2,607	-	399
Total	133,315	83,559	1,413	40,702	2,704	4,538	-	399
(403-361) Struct & Impmnts	1,053,041							
- Demand	565,780	396,211	5,690	139,623	9,005	15,252	-	-
- Customer	-	-	-	-	-	-	-	-
- Commodity	487,261	263,813	5,474	181,881	12,350	20,593	-	3,150
Total	1,053,041	660,024	11,164	321,504	21,355	35,845	-	3,150
(403-362) Station Equip	8,786,195							
- Demand	4,720,665	3,305,840	47,475	1,164,961	75,136	127,253	-	-
- Customer	-	-	-	-	-	-	-	-
- Commodity	4,065,530	2,201,163	45,671	1,517,552	103,043	171,821	-	26,280
Total	8,786,195	5,507,003	93,146	2,682,513	178,179	299,074	-	26,280
(403-364) Poles, Towers & Fixt	18,139,318							
- Demand	9,745,931	6,824,989	98,014	2,405,090	155,121	262,717	-	-
- Customer	-	-	-	-	-	-	-	-
- Commodity	8,393,388	4,544,357	94,288	3,133,024	212,734	354,728	-	54,256
Total	18,139,318	11,369,345	192,302	5,538,115	367,855	617,446	-	54,256
(403-365) OH Cond & Dev	41,977,810							
- Demand	22,553,926	15,794,313	226,822	5,565,833	358,979	607,978	-	-
- Customer	-	-	-	-	-	-	-	-
- Commodity	19,423,885	10,516,500	218,201	7,250,410	492,307	820,908	-	125,558
Total	41,977,810	26,310,813	445,023	12,816,244	851,286	1,428,886	-	125,558
(403-366) UG Conduit	1,100,797							
- Demand	585,178	400,494	5,751	141,132	9,103	28,698	-	-
- Customer	-	-	-	-	-	-	-	-
- Commodity	515,619	269,581	5,593	185,858	12,620	38,748	-	3,219
Total	1,100,797	670,075	11,345	326,990	21,722	67,446	-	3,219
(403-367) UG Cond & Dev	12,821,695							
- Demand	6,888,867	4,824,212	69,281	1,700,027	109,646	185,701	-	-
- Customer	-	-	-	-	-	-	-	-
- Commodity	5,932,828	3,212,158	66,647	2,214,564	150,370	250,738	-	38,350
Total	12,821,695	8,036,370	135,928	3,914,591	260,017	436,439	-	38,350

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Total System	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
(403-368) Line Transformers	18,448,452								
- Demand	10,043,180	7,227,992	103,801	2,547,107	164,280	-	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	8,405,272	4,751,607	98,589	3,275,910	222,436	-	-		56,730
Total	18,448,452	11,979,600	202,390	5,823,016	386,717	-	-		56,730
(403-369) Services	7,940,911								
- Demand	3,970,455	2,857,503	41,037	1,006,969	64,946	-	-		-
- Customer	3,970,455	3,472,405	49,145	448,257	649	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	7,940,911	6,329,909	90,182	1,455,226	65,595	-	-		-
(403-370) Meters	10,227,000								
- Demand	4,550,528	2,069,422	220,462	2,240,016	20,628	-	-		-
- Customer	5,676,473	4,333,347	58,228	544,494	12,010	367,687	356,815		-
- Commodity	-	-	-	-	-	-	-		-
Total	10,227,000	6,402,768	278,689	2,784,510	32,638	367,687	356,815		-
(403-371) Install on Cust Premise	1,173,277								
- Demand	1,173,277	-	-	-	-	-	-		1,173,277
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	1,173,277	-	-	-	-	-	-		1,173,277
(403-373) St Lt & Signal Sys	8,028,829								
- Demand	8,028,829	-	-	-	-	-	-		8,028,829
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	8,028,829	-	-	-	-	-	-		8,028,829
(403-374) Asset Ret Costs	-								
- Demand	-	-	-	-	-	-	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	-	-	-	-	-	-	-		-
(403-389) Land & Land Rights	425								
- Demand	220	140	2	49	3	11	13		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	205	97	2	67	5	16	16		1
Total	425	237	4	116	8	27	29		1
(403-390) Struct & Impmnts -	1,351,046								
- Demand	699,553	445,073	6,392	156,841	10,116	35,741	40,494		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	651,492	307,620	6,383	212,083	14,401	49,413	51,753		3,673
Total	1,351,046	752,693	12,774	368,924	24,516	85,154	92,247		3,673
(403-391) Office Furn & Equip	6,668,521								
- Demand	3,452,870	2,196,800	31,548	774,141	49,930	176,411	199,872		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	3,215,651	1,518,357	31,504	1,046,804	71,079	243,893	255,443		18,128
Total	6,668,521	3,715,157	63,052	1,820,945	121,008	420,304	455,315		18,128
(403-392) Transportation Equip	1,548,578								
- Demand	801,833	510,146	7,326	179,773	11,595	40,967	46,415		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	746,745	352,596	7,316	243,091	16,506	56,637	59,320		4,210
Total	1,548,578	862,742	14,642	422,864	28,101	97,604	105,734		4,210
(403-393) Stores Equip	20,260								
- Demand	10,490	6,674	96	2,352	152	536	607		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	9,770	4,613	96	3,180	216	741	776		55
Total	20,260	11,287	192	5,532	368	1,277	1,383		55
(403-394) Tools, Shop & Garage Equip	930,182								
- Demand	481,636	306,428	4,401	107,984	6,965	24,607	27,880		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	448,546	211,793	4,394	146,017	9,915	34,020	35,631		2,529
Total	930,182	518,222	8,795	254,001	16,879	58,628	63,511		2,529
(403-395) Laboratory Equip	19,083								
- Demand	9,881	6,286	90	2,215	143	505	572		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	9,202	4,345	90	2,996	203	698	731		52
Total	19,083	10,631	180	5,211	346	1,203	1,303		52
(403-396) Power Operated Equip	58,193								
- Demand	30,131	19,170	275	6,756	436	1,539	1,744		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	28,061	13,250	275	9,135	620	2,128	2,229		158
Total	58,193	32,420	550	15,890	1,056	3,668	3,973		158
(403-397) Communication Equip	3,293,153								
- Demand	1,705,151	1,084,858	15,580	382,298	24,657	87,118	98,704		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	1,588,003	749,819	15,558	516,949	35,101	120,443	126,147		8,952
Total	3,293,153	1,834,677	31,137	899,247	59,758	207,561	224,851		8,952
(403-398) MISC Equip	(17,233)								
- Demand	(8,923)	(5,677)	(82)	(2,001)	(129)	(456)	(517)		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	(8,310)	(3,924)	(81)	(2,705)	(184)	(630)	(660)		(47)
Total	(17,233)	(9,601)	(163)	(4,706)	(313)	(1,086)	(1,177)		(47)
Total Depreciation Expense	143,702,850								
- Demand	80,081,086	48,321,035	884,681	18,538,843	1,071,851	1,596,509	415,784		9,202,106
- Customer	9,646,928	7,805,752	107,373	992,750	12,659	367,687	356,815		-
- Commodity	53,974,835	28,951,145	600,691	19,959,842	1,355,285	2,167,502	531,386		345,652
Total	143,702,850	85,077,932	1,592,746	39,491,436	2,439,795	4,131,699	1,303,985		9,547,758

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Total System	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
Depreciation Adjustment									
Adjustment									
Annualize Deprec Exp	9,581,673								
- Demand	5,339,565	3,221,901	58,988	1,236,114	71,468	106,450	27,723		613,569
- Customer	643,228	520,464	7,159	66,194	844	24,516	23,791		-
- Commodity	3,598,879	1,930,375	40,052	1,330,862	90,366	144,523	35,431		23,047
Total	9,581,673	5,672,740	106,199	2,633,170	162,678	275,489	86,946		636,616
Average Net Salvage	4,309,921								
- Demand	2,397,704	1,511,469	24,645	555,909	33,946	42,086	-		229,648
- Customer	277,616	233,069	3,251	29,858	216	5,665	5,497		-
- Commodity	1,634,601	891,936	18,506	614,929	41,754	56,826	-		10,649
Total	4,309,921	2,636,474	46,402	1,200,696	75,917	104,577	5,497		240,297
Total Depreciation Adjustment	13,891,594								
- Demand	7,737,270	4,733,370	83,633	1,792,024	105,414	148,537	27,723		843,217
- Customer	920,844	753,533	10,410	96,051	1,060	30,181	29,289		-
- Commodity	5,233,480	2,822,311	58,559	1,945,791	132,120	201,348	35,431		33,696
Total	13,891,594	8,309,215	152,602	3,833,866	238,595	380,066	92,443		876,913
Total Depreciation Expense									
- Demand	87,818,356	53,054,404	968,314	20,330,867	1,177,265	1,745,046	443,507		10,045,323
- Customer	10,567,773	8,559,285	117,783	1,088,802	13,719	397,869	386,104		-
- Commodity	59,208,315	31,773,456	659,250	21,905,633	1,487,406	2,368,850	566,817		379,348
Total	**157,594,444**	**93,387,146**	**1,745,347**	**43,325,302**	**2,678,390**	**4,511,765**	**1,396,428**		**10,424,671**
Amortization, Accretion, Regulatory Debits and Credits									
Amort - Ltd Term Elec Prpty	12,450,296								
- Demand	6,964,338	4,316,967	71,706	1,598,183	96,773	121,922	-		758,787
- Customer	824,988	689,377	9,599	88,234	699	18,717	18,164		-
- Commodity	4,660,969	2,541,842	52,739	1,752,427	118,991	164,623	-		30,347
Total	12,450,296	7,548,186	134,044	3,438,843	216,463	305,262	18,164		789,135
Accretion Expense	403,950								
- Demand	209,160	133,073	1,911	46,894	3,025	10,686	12,107		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	194,790	91,975	1,908	63,411	4,306	14,774	15,474		1,098
Total	403,950	225,048	3,819	110,305	7,330	25,460	27,581		1,098
Regulatory Debits	65,491,174								
- Demand	33,910,449	21,574,649	309,834	7,602,793	490,356	1,732,523	1,962,931		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	31,580,725	14,911,701	309,395	10,280,602	698,059	2,395,258	2,508,693		178,033
Total	65,491,174	36,486,349	619,228	17,883,395	1,188,415	4,127,781	4,471,623		178,033
Regulatory Credits	27,279								
- Demand	14,125	8,986	129	3,167	204	722	818		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	13,154	6,211	129	4,282	291	998	1,045		74
Total	27,279	15,197	258	7,449	495	1,719	1,863		74
Total Depreciation and Amortization	235,967,143								
- Demand	128,916,428	79,088,079	1,351,893	29,581,903	1,767,623	3,610,899	2,419,363		10,804,110
- Customer	11,392,761	9,248,663	127,382	1,177,036	14,418	416,586	404,267		-
- Commodity	95,657,954	49,325,186	1,023,421	34,006,355	2,309,052	4,944,503	3,092,029		588,901
Total	**235,967,143**	**137,661,927**	**2,502,697**	**64,765,294**	**4,091,094**	**8,971,988**	**5,915,659**		**11,393,011**
TAXES									
Taxes Other than Income									
(408) Payroll Taxes	3,540,635								
- Demand	1,866,258	1,183,478	27,078	496,904	25,503	58,466	-		74,828
- Customer	312,661	238,987	3,218	30,063	637	19,434	20,115		-
- Commodity	1,361,715	729,469	15,089	495,744	33,457	79,158	206		8,571
Total	3,540,635	2,151,934	45,385	1,022,712	59,597	157,059	20,321		83,399
(408) Property Taxes	5,376,967								
- Demand	2,970,617	1,915,546	32,021	710,767	42,913	62,118	14,348		191,168
- Customer	251,324	204,820	2,825	26,088	303	8,665	8,530		-
- Commodity	2,155,026	1,159,232	24,050	798,850	54,232	84,294	18,348		13,833
Total	5,376,967	3,279,599	58,897	1,535,704	97,448	155,077	41,227		205,001
Total Taxes Other than Income	8,917,602								
- Demand	4,836,875	3,099,024	59,099	1,207,671	68,415	120,585	14,348		265,997
- Customer	563,986	443,808	6,044	56,151	940	28,100	28,645		-
- Commodity	3,516,741	1,888,701	39,139	1,294,593	87,690	163,452	18,554		22,404
Total Taxes Other than Income	**8,917,602**	**5,431,533**	**104,282**	**2,558,416**	**157,045**	**312,136**	**61,548**		**288,401**
Total Expenses	**559,325,317**								
- Demand	**299,132,766**	**187,465,827**	**3,757,688**	**74,644,980**	**4,124,630**	**8,932,780**	**2,582,611**		**17,314,069**
- Customer	**38,505,559**	**30,045,318**	**408,696**	**3,805,713**	**68,312**	**2,054,688**	**2,101,088**		**-**
- Commodity	**221,686,992**	**116,871,208**	**2,420,066**	**79,802,547**	**5,396,743**	**12,121,741**	**3,296,790**		**1,385,861**
Total	**559,325,317**	**334,382,353**	**6,586,450**	**158,253,239**	**9,589,685**	**23,109,209**	**7,980,489**		**18,699,930**

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Total System	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
REVENUE REQUIREMENT CALCULATION									
Total Rate Base									
- Demand	1,653,723,168	1,059,438,732	17,889,138	394,524,131	23,709,033	35,674,914	8,184,052		113,313,529
- Customer	138,841,265	112,550,359	1,549,432	14,320,290	178,078	5,136,353	5,052,215		-
- Commodity	1,194,930,837	641,658,079	13,312,019	442,165,010	30,017,179	48,408,961	10,465,658		7,656,716
Total	2,987,495,271	1,813,647,170	32,750,589	851,009,430	53,904,290	89,220,227	23,701,925		120,970,245
Required Net Income									
- Demand	125,682,961	80,517,344	1,359,574	29,983,834	1,801,887	2,711,293	621,988		8,611,828
- Customer	10,551,936	8,553,827	117,757	1,088,342	13,534	390,363	383,968		-
- Commodity	90,814,744	48,766,014	1,011,713	33,604,541	2,281,306	3,679,081	795,390		581,910
Total	227,049,641	137,837,185	2,489,045	64,676,717	4,096,726	6,780,737	1,801,346		9,193,739
Interest Synchronization									
- Demand	36,367,555	23,298,456	393,406	8,676,106	521,393	784,538	179,978		2,491,914
- Customer	3,053,303	2,475,131	34,074	314,922	3,916	112,955	111,105		-
- Commodity	26,278,106	14,110,908	292,749	9,723,792	660,117	1,064,577	230,154		168,381
Total	65,698,964	39,884,495	720,229	18,714,821	1,185,426	1,962,071	521,237		2,660,295
Net Income Before Income Taxes									
- Demand	89,315,406	57,218,888	966,169	21,307,728	1,280,494	1,926,755	442,010		6,119,914
- Customer	7,498,633	6,078,696	83,683	773,420	9,618	277,408	272,863		-
- Commodity	64,536,637	34,655,106	718,965	23,880,749	1,621,188	2,614,504	565,236		413,529
Total	161,350,677	97,952,690	1,768,816	45,961,896	2,911,300	4,818,667	1,280,110		6,533,443
Taxable Income									
- Demand	124,238,984	79,592,277	1,343,954	29,639,348	1,781,185	2,680,143	614,842		8,512,887
- Customer	10,430,705	8,455,552	116,404	1,075,838	13,378	385,878	379,557		-
- Commodity	89,771,369	48,205,739	1,000,090	33,218,457	2,255,096	3,636,812	786,252		575,225
Total	224,441,058	136,253,568	2,460,448	63,933,643	4,049,659	6,702,833	1,780,651		9,088,111
NJ State Corporate Business Tax									
- Demand	11,181,509	7,163,305	120,956	2,667,541	160,307	241,213	55,336		766,160
- Customer	938,763	761,000	10,476	96,825	1,204	34,729	34,160		-
- Commodity	8,079,423	4,338,517	90,008	2,989,661	202,959	327,313	70,763		51,770
Total	20,199,695	12,262,821	221,440	5,754,028	364,469	603,255	160,259		817,930
Federal Taxable Income									
- Demand	113,057,476	72,428,972	1,222,998	26,971,807	1,620,878	2,438,930	559,506		7,746,727
- Customer	9,491,941	7,694,552	105,928	979,013	12,174	351,149	345,397		-
- Commodity	81,691,946	43,867,223	910,082	30,228,796	2,052,137	3,309,499	715,489		523,455
Total	204,241,363	123,990,747	2,239,008	58,179,615	3,685,189	6,099,578	1,620,392		8,270,181
Federal Income Tax									
- Demand	23,742,070	15,210,084	256,830	5,664,079	340,384	512,175	117,496		1,626,813
- Customer	1,993,308	1,615,856	22,245	205,593	2,557	73,741	72,533		-
- Commodity	17,155,309	9,212,117	191,117	6,348,047	430,949	694,995	150,253		109,925
Total	42,890,686	26,038,057	470,192	12,217,719	773,890	1,280,911	340,282		1,736,738
NJ Federal & State Income Tax	63,090,381								
- Demand	34,923,578	22,373,389	377,786	8,331,621	500,691	753,388	172,832		2,392,972
- Customer	2,932,071	2,376,856	32,721	302,418	3,761	108,470	106,693		-
- Commodity	25,234,732	13,550,633	281,125	9,337,708	633,907	1,022,308	221,015		161,696
Total	63,090,381	38,300,878	691,632	17,971,747	1,138,359	1,884,166	500,541		2,554,668
Tax Reform Amortization	(9,255,331)								
- Demand	(5,123,274)	(3,282,166)	(55,421)	(1,222,245)	(73,451)	(110,522)	(25,354)		(351,048)
- Customer	(430,134)	(348,684)	(4,800)	(44,365)	(552)	(15,913)	(15,652)		-
- Commodity	(3,701,924)	(1,987,872)	(41,241)	(1,369,838)	(92,994)	(149,972)	(32,423)		(23,721)
Total	(9,255,331)	(5,618,722)	(101,462)	(2,636,447)	(166,997)	(276,406)	(73,429)		(374,769)
Investment Tax Credit	(134,977)								
- Demand	(74,716)	(47,866)	(808)	(17,825)	(1,071)	(1,612)	(370)		(5,120)
- Customer	(6,273)	(5,085)	(70)	(647)	(8)	(232)	(228)		-
- Commodity	(53,988)	(28,991)	(601)	(19,977)	(1,356)	(2,187)	(473)		(346)
Total	(134,977)	(81,942)	(1,480)	(38,449)	(2,435)	(4,031)	(1,071)		(5,466)
Federal & State Income Taxes									
- Demand	29,725,588	19,043,356	321,556	7,091,551	426,169	641,255	147,108		2,036,805
- Customer	2,495,665	2,023,087	27,851	257,406	3,201	92,326	90,813		-
- Commodity	21,478,820	11,533,771	239,283	7,947,893	539,557	870,149	188,120		137,629
Total	53,700,073	32,600,214	588,690	15,296,851	968,927	1,603,729	426,041		2,174,434
Revenue Requirement									
- Demand	**454,541,316**	**287,026,527**	**5,438,819**	**111,720,365**	**6,352,685**	**12,285,328**	**3,351,707**		**27,962,702**
- Customer	**51,553,160**	**40,622,232**	**554,303**	**5,151,461**	**85,047**	**2,537,377**	**2,575,869**		**-**
- Commodity	**333,980,555**	**177,170,992**	**3,671,063**	**121,354,981**	**8,217,606**	**16,670,971**	**4,280,299**		**2,105,400**
Total	**840,075,031**	**504,819,752**	**9,664,185**	**238,226,807**	**14,655,338**	**31,493,676**	**10,207,876**		**30,068,103**

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG	Classification Factor
UTILITY PLANT											
Intangible Plant											
(301) Organizational Costs		17,406									AE-ALL
- Demand	DMD-ALL	9,013	5,734	82	2,021	130	460	522		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	8,394	3,963	82	2,732	186	637	667		47	48%
Total		17,406	9,697	165	4,753	316	1,097	1,188		47	
(302) Franchises & Consents		924									AE-ALL
- Demand	DMD-ALL	479	305	4	107	7	24	28		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	446	210	4	145	10	34	35		3	48%
Total		924	515	9	252	17	58	63		3	
(303) Misc. Intangible Plant		61,458,196									AE-ALL
- Demand	DMD-ALL	31,822,227	20,246,071	290,754	7,134,610	460,160	1,625,834	1,842,052		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	29,635,969	13,993,431	290,342	9,647,517	655,072	2,247,757	2,354,206		167,070	48%
Total		61,458,196	34,239,502	581,096	16,782,127	1,115,232	3,873,590	4,196,259		167,070	
Total Intangible Plant		61,476,527									
- Demand		31,831,718	20,252,110	290,841	7,136,738	460,297	1,626,318	1,842,602		-	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		29,644,808	13,997,605	290,429	9,650,395	655,268	2,248,427	2,354,908		167,120	
Total		61,476,527	34,249,714	581,269	16,787,132	1,115,565	3,874,746	4,197,510		167,120	
Distribution Plant											
(360) Land and Land Rights		16,328,813									AE-PRI
- Demand	DMD-PRI	8,657,091	5,890,028	84,587	2,075,615	133,871	472,991	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	7,671,722	3,975,889	82,494	2,741,104	186,123	638,645	-		47,469	47%
Total		16,328,813	9,865,916	167,080	4,816,719	319,993	1,111,635	-		47,469	
(361) Structures and Improvements		45,700,085									AE-PRI
- Demand	DMD-PRI	24,228,937	16,484,650	236,736	5,809,104	374,669	1,323,778	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	21,471,148	11,127,474	230,878	7,671,635	520,909	1,787,400	-		132,853	47%
Total		45,700,085	27,612,123	467,614	13,480,739	895,578	3,111,177	-		132,853	
(362) Station Equipment		294,950,319									AE-PRI
- Demand	DMD-PRI	156,374,604	106,392,641	1,527,905	37,492,211	2,418,130	8,543,718	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	138,575,715	71,817,196	1,490,096	49,513,064	3,361,967	11,535,955	-		857,437	47%
Total		294,950,319	178,209,837	3,018,001	87,005,274	5,780,097	20,079,673	-		857,437	
(364) Poles, Towers & Fixtures		395,829,391									AE-PRI
- Demand	DMD-PRI	209,857,933	142,781,111	2,050,480	50,315,317	3,245,180	11,465,845	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	185,971,458	96,380,153	1,999,739	66,447,549	4,511,829	15,481,489	-		1,150,698	47%
Total		395,829,391	239,161,265	4,050,219	116,762,867	7,757,009	26,947,334	-		1,150,698	
(365) Overhead Conductors & Devices		636,490,202									AE-PRI
- Demand	DMD-PRI	337,449,723	229,590,780	3,297,154	80,906,591	5,218,221	18,436,979	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	299,040,479	154,978,445	3,215,563	106,847,079	7,254,982	24,894,099	-		1,850,312	47%
Total		636,490,202	384,569,224	6,512,717	187,753,669	12,473,202	43,331,078	-		1,850,312	
(366) Underground Conduit		111,923,286									AE-PRI
- Demand	DMD-PRI	59,338,670	40,372,270	579,786	14,226,977	917,595	3,242,041	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	52,584,616	27,252,103	565,439	18,788,469	1,275,748	4,377,490	-		325,367	47%
Total		111,923,286	67,624,373	1,145,225	33,015,445	2,193,344	7,619,531	-		325,367	
(367) Underground Conductors & Device		347,686,952									AE-PRI
- Demand	DMD-PRI	184,334,127	125,415,471	1,801,092	44,195,756	2,850,487	10,071,321	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	163,352,825	84,657,993	1,756,522	58,365,918	3,963,081	13,598,565	-		1,010,745	47%
Total		347,686,952	210,073,464	3,557,614	102,561,675	6,813,569	23,669,886	-		1,010,745	
(368) Line Transformers		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(369) Services		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(370) Meters		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(371) Installation on Customers' Premises		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(373) Street Lighting & Signal Systems		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
(374) Asset Retirement Costs		45,657									AE-PRI
- Demand	DMD-PRI	24,206	16,469	237	5,804	374	1,323	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	21,451	11,117	231	7,664	520	1,786	-		133	47%
Total		45,657	27,586	467	13,468	895	3,108	-		133	
(375) Charging Stations		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
Total Distribution Plant		1,848,954,704									
- Demand		980,265,291	666,943,420	9,577,976	235,027,375	15,158,526	53,557,994	-		-	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		868,689,413	450,200,369	9,340,961	310,382,482	21,075,159	72,315,428	-		5,375,013	
Total		1,848,954,704	1,117,143,789	18,918,937	545,409,857	36,233,686	125,873,422	-		5,375,013	
General Plant											
(389) Land and Land Rights		526,704									AE-ALL
- Demand	DMD-ALL	272,720	173,511	2,492	61,144	3,944	13,934	15,787		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	253,984	119,925	2,488	82,680	5,614	19,264	20,176		1,432	48%
Total		526,704	293,437	4,980	143,825	9,558	33,197	35,962		1,432	
(390) Structures and Improvements		37,234,023									AE-ALL
- Demand	DMD-ALL	19,279,276	12,265,942	176,151	4,322,454	278,785	985,000	1,115,995		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	17,954,747	8,477,823	175,902	5,844,882	396,871	1,361,788	1,426,280		101,218	48%
Total		37,234,023	20,743,766	352,053	10,167,336	675,656	2,346,788	2,542,274		101,218	
(391) Office Furniture & Equipment		12,634,368									AE-ALL
- Demand	DMD-ALL	6,541,906	4,162,119	59,772	1,466,709	94,598	334,233	378,683		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	6,092,462	2,876,722	59,688	1,983,304	134,668	462,086	483,970		34,346	48%
Total		12,634,368	7,038,841	119,460	3,450,013	229,266	796,320	862,653		34,346	
(392) Transportation Equipment		6,134,927									AE-ALL
- Demand	DMD-ALL	3,176,583	2,021,019	29,024	712,196	45,934	162,295	183,879		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	2,958,344	1,396,863	28,983	963,042	65,391	224,377	235,003		16,677	48%
Total		6,134,927	3,417,882	58,007	1,675,238	111,326	386,672	418,882		16,677	
(393) Stores Equipment		394,355									AE-ALL
- Demand	DMD-ALL	204,192	129,912	1,866	45,780	2,953	10,432	11,820		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	190,163	89,791	1,863	61,905	4,203	14,423	15,106		1,072	48%
Total		394,355	219,702	3,729	107,685	7,156	24,855	26,926		1,072	
(394) Tools, Shop & Garage Equipment		8,500,184									AE-ALL
- Demand	DMD-ALL	4,401,281	2,800,202	40,214	986,776	63,644	224,866	254,771		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	4,098,903	1,935,409	40,157	1,334,333	90,602	310,884	325,606		23,107	48%
Total		8,500,184	4,735,611	80,370	2,321,109	154,246	535,750	580,378		23,107	
(395) Laboratory Equipment		150,316									AE-ALL
- Demand	DMD-ALL	77,832	49,518	711	17,450	1,125	3,977	4,505		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	72,485	34,226	710	23,596	1,602	5,498	5,758		409	48%
Total		150,316	83,744	1,421	41,046	2,728	9,474	10,263		409	
(396) Power Operated Equipment		720,982									AE-ALL
- Demand	DMD-ALL	373,315	237,512	3,411	83,698	5,398	19,073	21,610		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	347,667	164,161	3,406	113,178	7,685	26,369	27,618		1,960	48%
Total		720,982	401,673	6,817	196,876	13,083	45,442	49,227		1,960	
(397) Communication Equipment		22,934,891									AE-ALL
- Demand	DMD-ALL	11,875,378	7,555,403	108,503	2,662,485	171,722	606,726	687,415		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	11,059,513	5,222,051	108,349	3,600,248	244,459	838,815	878,540		62,347	48%
Total		22,934,891	12,777,454	216,853	6,262,733	416,181	1,445,541	1,565,954		62,347	
(398) Misc. Equipment		61,809									AE-ALL
- Demand	DMD-ALL	32,004	20,362	292	7,175	463	1,635	1,853		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	29,805	14,073	292	9,703	659	2,261	2,368		168	48%
Total		61,809	34,435	584	16,878	1,122	3,896	4,220		168	
(399) Other Tangible Property		513,937									AE-ALL
- Demand	DMD-ALL	266,110	169,305	2,431	59,662	3,848	13,596	15,404		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	247,827	117,018	2,428	80,676	5,478	18,797	19,687		1,397	48%
Total		513,937	286,324	4,859	140,339	9,326	32,392	35,091		1,397	
(SRVCO-PIS) Service Company PIS		49,148,990									AE-ALL
- Demand	DMD-ALL	25,448,686	16,191,070	232,520	5,705,648	367,996	1,300,202	1,473,115		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	23,700,304	11,190,745	232,191	7,715,256	523,871	1,797,563	1,882,692		133,608	48%
Total		49,148,990	27,381,815	464,711	13,420,905	891,867	3,097,765	3,355,808		133,608	
Total General Plant		138,955,488									
- Demand		71,949,282	45,775,875	657,387	16,131,179	1,040,410	3,675,970	4,164,836		-	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		67,006,206	31,638,807	656,456	21,812,802	1,481,103	5,082,123	5,322,803		377,741	
Total		138,955,488	77,414,682	1,313,844	37,943,981	2,521,513	8,758,094	9,487,639		377,741	
Total Utility Plant		2,049,386,718									
- Demand		1,084,046,291	732,971,404	10,526,204	258,295,292	16,659,234	58,860,283	6,007,438		-	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		965,340,427	495,836,781	10,287,846	341,845,679	23,211,529	79,645,978	7,677,712		5,919,873	
Total		2,049,386,718	1,228,808,185	20,814,050	600,140,971	39,870,763	138,506,261	13,685,149		5,919,873	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
Additions to Utility Plant											
Construction Work in Progress		-									
- Demand		-	-	-	-	-	-	-		-	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		-	-	-	-	-	-	-		-	
Total		-	-	-	-	-	-	-		-	
Total Additional to Utility Plant		-									
- Demand		-	-	-	-	-	-	-		-	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		-	-	-	-	-	-	-		-	
Total		-	-	-	-	-	-	-		-	
Total Utility Plant		2,049,386,718									
- Demand		1,084,046,291	732,971,404	10,526,204	258,295,292	16,659,234	58,860,283	6,007,438		-	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		965,340,427	495,836,781	10,287,846	341,845,679	23,211,529	79,645,978	7,677,712		5,919,873	
Total		**2,049,386,718**	**1,228,808,185**	**20,814,050**	**600,140,971**	**39,870,763**	**138,506,261**	**13,685,149**		**5,919,873**	
ACCUMULATED DEPRECIATION											
Accumulated Depreciation											
(108-303) Misc Intangible Plant		(39,337,657)									AE-ALL
- Demand	DMD-ALL	(20,368,509)	(12,958,939)	(186,103)	(4,566,662)	(294,535)	(1,040,650)	(1,179,046)		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(18,969,147)	(8,956,800)	(185,840)	(6,175,103)	(419,293)	(1,438,726)	(1,506,861)		(106,937)	48%
Total		(39,337,657)	(21,915,739)	(371,943)	(10,741,766)	(713,829)	(2,479,376)	(2,685,907)		(106,937)	
(108-360) Land & Land Rights		(9,226,037)									AE-PRI
- Demand	DMD-PRI	(4,891,393)	(3,327,959)	(47,793)	(1,172,755)	(75,639)	(267,247)	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	(4,334,644)	(2,246,440)	(46,610)	(1,548,767)	(105,162)	(360,844)	-		(26,821)	47%
Total		(9,226,037)	(5,574,398)	(94,403)	(2,721,522)	(180,801)	(628,092)	-		(26,821)	
(108-361) Struct & Impmnts		(8,588,758)									AE-PRI
- Demand	DMD-PRI	(4,553,525)	(3,098,083)	(44,492)	(1,091,748)	(70,414)	(248,787)	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	(4,035,233)	(2,091,269)	(43,391)	(1,441,788)	(97,898)	(335,919)	-		(24,968)	47%
Total		(8,588,758)	(5,189,353)	(87,882)	(2,533,536)	(168,313)	(584,707)	-		(24,968)	
(108-362) Station Equip		(102,333,669)									AE-PRI
- Demand	DMD-PRI	(54,254,517)	(36,913,163)	(530,110)	(13,008,006)	(838,975)	(2,964,262)	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	(48,079,152)	(24,917,136)	(516,992)	(17,178,668)	(1,166,442)	(4,002,425)	-		(297,490)	47%
Total		(102,333,669)	(61,830,299)	(1,047,102)	(30,186,673)	(2,005,417)	(6,966,687)	-		(297,490)	
(108-364) Poles, Towers & Fixt		(151,290,456)									AE-PRI
- Demand	DMD-PRI	(80,210,068)	(54,572,550)	(783,716)	(19,231,082)	(1,240,344)	(4,382,375)	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	(71,080,388)	(36,837,581)	(764,323)	(25,397,002)	(1,724,472)	(5,917,200)	-		(439,810)	47%
Total		(151,290,456)	(91,410,132)	(1,548,039)	(44,628,084)	(2,964,816)	(10,299,575)	-		(439,810)	
(108-365) OH Cond & Dev		(97,687,661)									AE-PRI
- Demand	DMD-PRI	(51,791,330)	(35,237,284)	(506,043)	(12,417,435)	(800,885)	(2,829,683)	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	(45,896,331)	(23,785,883)	(493,520)	(16,398,746)	(1,113,485)	(3,820,713)	-		(283,983)	47%
Total		(97,687,661)	(59,023,168)	(999,563)	(28,816,181)	(1,914,370)	(6,650,396)	-		(283,983)	
(108-366) UG Conduit		(55,819,012)									AE-PRI
- Demand	DMD-PRI	(29,593,716)	(20,134,686)	(289,154)	(7,095,358)	(457,628)	(1,616,889)	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	(26,225,296)	(13,591,323)	(281,999)	(9,370,291)	(636,248)	(2,183,166)	-		(162,269)	47%
Total		(55,819,012)	(33,726,009)	(571,153)	(16,465,649)	(1,093,877)	(3,800,055)	-		(162,269)	
(108-367) UG Cond & Dev		(117,495,009)									AE-PRI
- Demand	DMD-PRI	(62,292,645)	(42,382,068)	(608,649)	(14,935,219)	(963,275)	(3,403,435)	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	(55,202,364)	(28,608,757)	(593,587)	(19,723,789)	(1,339,257)	(4,595,408)	-		(341,564)	47%
Total		(117,495,009)	(70,990,825)	(1,202,236)	(34,659,008)	(2,302,532)	(7,998,843)	-		(341,564)	
(108-368) Line Transformers		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(108-369) Services		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(108-370) Meters		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(108-371) Install on Cust Premise		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(108-373) St Lt & Signal Sys		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
(108-374) Asset Ret Costs		-									AE-PRI
- Demand	DMD-PRI	-	-	-	-	-	-	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	-	-	-	-	-	-	-		-	47%
Total		-	-	-	-	-	-	-		-	
(108-389) Land & Land Rights		(2,435)									AE-ALL
- Demand	DMD-ALL	(1,261)	(802)	(12)	(283)	(18)	(64)	(73)		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(1,174)	(554)	(12)	(382)	(26)	(89)	(93)		(7)	48%
Total		(2,435)	(1,357)	(23)	(665)	(44)	(153)	(166)		(7)	
(108-390) Struct & Impmnts -		(19,784,136)									AE-ALL
- Demand	DMD-ALL	(10,243,959)	(6,517,455)	(93,597)	(2,296,717)	(148,131)	(523,375)	(592,979)		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(9,540,176)	(4,504,654)	(93,465)	(3,105,652)	(210,876)	(723,580)	(757,847)		(53,782)	48%
Total		(19,784,136)	(11,022,109)	(187,062)	(5,402,369)	(359,007)	(1,246,956)	(1,350,826)		(53,782)	
(108-391) Office Furn & Equip		(2,208,819)									AE-ALL
- Demand	DMD-ALL	(1,143,697)	(727,648)	(10,450)	(256,419)	(16,538)	(58,433)	(66,204)		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(1,065,122)	(502,927)	(10,435)	(346,734)	(23,543)	(80,785)	(84,611)		(6,005)	48%
Total		(2,208,819)	(1,230,574)	(20,885)	(603,153)	(40,082)	(139,218)	(150,814)		(6,005)	
(108-392) Transportation Equip		(1,822,045)									AE-ALL
- Demand	DMD-ALL	(943,430)	(600,233)	(8,620)	(211,519)	(13,642)	(48,201)	(54,611)		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(878,615)	(414,862)	(8,608)	(286,019)	(19,421)	(66,639)	(69,795)		(4,953)	48%
Total		(1,822,045)	(1,015,095)	(17,228)	(497,538)	(33,063)	(114,840)	(124,406)		(4,953)	
(108-393) Stores Equip		(337,645)									AE-ALL
- Demand	DMD-ALL	(174,828)	(111,230)	(1,597)	(39,197)	(2,528)	(8,932)	(10,120)		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(162,817)	(76,878)	(1,595)	(53,002)	(3,599)	(12,349)	(12,934)		(918)	48%
Total		(337,645)	(188,108)	(3,192)	(92,199)	(6,127)	(21,281)	(23,054)		(918)	
(108-394) Tools, Shop & Garage Equip		(3,774,911)									AE-ALL
- Demand	DMD-ALL	(1,954,598)	(1,243,562)	(17,859)	(438,225)	(28,264)	(99,863)	(113,143)		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(1,820,313)	(859,510)	(17,834)	(592,574)	(40,236)	(138,063)	(144,601)		(10,262)	48%
Total		(3,774,911)	(2,103,073)	(35,692)	(1,030,799)	(68,500)	(237,925)	(257,744)		(10,262)	
(108-395) Laboratory Equip		(147,631)									AE-ALL
- Demand	DMD-ALL	(76,441)	(48,634)	(698)	(17,138)	(1,105)	(3,905)	(4,425)		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(71,190)	(33,614)	(697)	(23,175)	(1,574)	(5,399)	(5,655)		(401)	48%
Total		(147,631)	(82,248)	(1,396)	(40,313)	(2,679)	(9,305)	(10,080)		(401)	
(108-396) Power Operated Equip		(423,708)									AE-ALL
- Demand	DMD-ALL	(219,390)	(139,582)	(2,005)	(49,188)	(3,172)	(11,209)	(12,700)		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(204,318)	(96,474)	(2,002)	(66,512)	(4,516)	(15,497)	(16,230)		(1,152)	48%
Total		(423,708)	(236,056)	(4,006)	(115,700)	(7,689)	(26,706)	(28,930)		(1,152)	
(108-397) Communication Equip		(4,617,461)									AE-ALL
- Demand	DMD-ALL	(2,390,859)	(1,521,122)	(21,845)	(536,036)	(34,573)	(122,152)	(138,397)		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(2,226,602)	(1,051,351)	(21,814)	(724,835)	(49,217)	(168,878)	(176,876)		(12,552)	48%
Total		(4,617,461)	(2,572,473)	(43,659)	(1,260,870)	(83,789)	(291,030)	(315,272)		(12,552)	
(108-398) MISC Equip		(75,583)									AE-ALL
- Demand	DMD-ALL	(39,136)	(24,899)	(358)	(8,774)	(566)	(1,999)	(2,265)		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(36,447)	(17,209)	(357)	(11,865)	(806)	(2,764)	(2,895)		(205)	48%
Total		(75,583)	(42,108)	(715)	(20,639)	(1,372)	(4,764)	(5,161)		(205)	
(108-399) Other Tangible Property		-									AE-ALL
- Demand	DMD-ALL	-	-	-	-	-	-	-		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	-	-	-	-	-	-	-		-	48%
Total		-	-	-	-	-	-	-		-	
Service Company PIS		(30,206,435)									AE-ALL
- Demand	DMD-ALL	(15,640,485)	(9,950,855)	(142,904)	(3,506,629)	(226,167)	(799,090)	(905,361)		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(14,565,949)	(6,877,710)	(142,702)	(4,741,713)	(321,965)	(1,104,763)	(1,157,082)		(82,114)	48%
Total		(30,206,435)	(16,828,565)	(285,606)	(8,248,342)	(548,132)	(1,903,853)	(2,062,443)		(82,114)	
Total Accumulated Depreciation		(645,179,067)									
- Demand		(340,783,788)	(229,510,755)	(3,296,004)	(80,878,391)	(5,216,402)	(18,430,553)	(3,079,323)		-	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		(304,395,278)	(155,470,934)	(3,225,781)	(107,186,617)	(7,278,036)	(24,973,207)	(3,935,481)		(1,856,192)	
Total Accumulated Depreciation		**(645,179,067)**	**(384,981,689)**	**(6,521,786)**	**(188,065,007)**	**(12,494,438)**	**(43,403,760)**	**(7,014,804)**		**(1,856,192)**	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG	Classification Factor
OTHER RATE BASE ITEMS											
Other Rate Base Items											
Materials and Supplies		8,850,642									DISTPLT-PRI
- Demand	DISTPLT-PRI-D	4,692,369	3,192,549	45,848	1,125,037	72,561	256,373	-		-	53%
- Customer	DISTPLT-PRI-C	-	-	-	-	-	-	-		-	0%
- Commodity	DISTPLT-PRI-E	4,158,273	2,155,035	44,714	1,485,750	100,883	346,162	-		25,729	47%
Total		8,850,642	5,347,584	90,562	2,610,787	173,445	602,535	-		25,729	
Cash Working Capital		37,799,695									CWC-PRI
- Demand	CWC-PRI-D	20,040,366	13,634,870	195,810	4,804,857	309,898	1,094,930	-		-	53%
- Customer	CWC-PRI-C	-	-	-	-	-	-	-		-	0%
- Commodity	CWC-PRI-E	17,759,329	9,203,815	190,965	6,345,403	430,857	1,478,404	-		109,886	47%
Total		37,799,695	22,838,685	386,775	11,150,260	740,755	2,573,333	-		109,886	
ADIT		(404,577,206)									DISTPLT-PRI
- Demand	DISTPLT-PRI-D	(214,495,786)	(145,936,569)	(2,095,795)	(51,427,284)	(3,316,898)	(11,719,240)	-		-	53%
- Customer	DISTPLT-PRI-C	-	-	-	-	-	-	-		-	0%
- Commodity	DISTPLT-PRI-E	(190,081,420)	(98,510,151)	(2,043,933)	(67,916,038)	(4,611,540)	(15,823,629)	-		(1,176,128)	47%
Total		(404,577,206)	(244,446,720)	(4,139,729)	(119,343,322)	(7,928,438)	(27,542,869)	-		(1,176,128)	
Net /Loss on Reacq Debt		463,605									DISTPLT-PRI
- Demand	DISTPLT-PRI-D	245,791	167,229	2,402	58,931	3,801	13,429	-		-	53%
- Customer	DISTPLT-PRI-C	-	-	-	-	-	-	-		-	0%
- Commodity	DISTPLT-PRI-E	217,814	112,883	2,342	77,825	5,284	18,132	-		1,348	47%
Total		463,605	280,112	4,744	136,756	9,085	31,561	-		1,348	
DTA for AMT		3,217,478									DISTPLT-PRI
- Demand	DISTPLT-PRI-D	1,705,819	1,160,589	16,667	408,985	26,378	93,200	-		-	53%
- Customer	DISTPLT-PRI-C	-	-	-	-	-	-	-		-	0%
- Commodity	DISTPLT-PRI-E	1,511,659	783,421	16,255	540,115	36,674	125,840	-		9,353	47%
Total		3,217,478	1,944,009	32,922	949,101	63,052	219,040	-		9,353	
Net Operating Reserves		(3,161,542)									PAY-PRI
- Demand	PAY-PRI-D	(1,675,571)	(1,140,009)	(16,372)	(401,733)	(25,911)	(91,547)	-		-	53%
- Customer	PAY-PRI-C	(1,117)	-	-	-	-	-	(1,117)		-	0%
- Commodity	PAY-PRI-E	(1,484,854)	(769,529)	(15,967)	(530,538)	(36,024)	(123,609)	-		(9,188)	47%
Total		(3,161,542)	(1,909,537)	(32,338)	(932,271)	(61,934)	(215,156)	(1,117)		(9,188)	
NOL		12,202,176									DISTPLT-PRI
- Demand	DISTPLT-PRI-D	6,469,260	4,401,493	63,210	1,551,063	100,039	353,456	-		-	53%
- Customer	DISTPLT-PRI-C	-	-	-	-	-	-	-		-	0%
- Commodity	DISTPLT-PRI-E	5,732,915	2,971,097	61,646	2,048,369	139,086	477,246	-		35,472	47%
Total		12,202,176	7,372,590	124,856	3,599,432	239,124	830,702	-		35,472	
CTA		(325,992)									TOTPLT-PRI
- Demand	TOTPLT-PRI-D	(172,437)	(116,592)	(1,674)	(41,086)	(2,650)	(9,363)	(956)		-	52.896131%
- Customer	TOTPLT-PRI-C	-	-	-	-	-	-	-		-	0.000000%
- Commodity	TOTPLT-PRI-E	(153,555)	(78,872)	(1,636)	(54,377)	(3,692)	(12,669)	(1,221)		(942)	47.103869%
Total		(325,992)	(195,464)	(3,311)	(95,463)	(6,342)	(22,032)	(2,177)		(942)	
Regulatory Asset A&G Capitalization		18,565,864									AE-PRI-GTA&G
- Demand	DMD-PRI	9,830,422	6,688,327	96,051	2,356,932	152,015	537,097	-		-	53%
- Customer	CUST-GTA&G	23,939	-	-	-	-	-	23,939		-	0%
- Commodity	NRG-PRI	8,711,503	4,514,757	93,674	3,112,617	211,349	725,203	-		53,902	47%
Total		18,565,864	11,203,085	189,725	5,469,549	363,363	1,262,300	23,939		53,902	
Customer Deposits		-									CUS
- Demand		-	-	-	-	-	-	-		-	0%
- Customer		-	-	-	-	-	-	-		-	100%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		-	-	-	-	-	-	-		-	
Customer Advances		(16,845,133)									DISTPLT-PRI
- Demand	DISTPLT-PRI-D	(8,930,829)	(6,076,271)	(87,261)	(2,141,246)	(138,104)	(487,947)	-		-	53%
- Customer	DISTPLT-PRI-C	-	-	-	-	-	-	-		-	0%
- Commodity	DISTPLT-PRI-E	(7,914,303)	(4,101,607)	(85,102)	(2,827,778)	(192,008)	(658,839)	-		(48,970)	47%
Total		(16,845,133)	(10,177,878)	(172,363)	(4,969,025)	(330,112)	(1,146,786)	-		(48,970)	
Customer Refunds		(94,007)									DISTPLT-PRI
- Demand	DISTPLT-PRI-D	(49,840)	(33,910)	(487)	(11,950)	(771)	(2,723)	-		-	53%
- Customer	DISTPLT-PRI-C	-	-	-	-	-	-	-		-	0%
- Commodity	DISTPLT-PRI-E	(44,167)	(22,890)	(475)	(15,781)	(1,072)	(3,677)	-		(273)	47%
Total		(94,007)	(56,799)	(962)	(27,731)	(1,842)	(6,400)	-		(273)	
Total Other Rate Base Items		(343,904,419)									
- Demand		(182,340,436)	(124,058,294)	(1,781,601)	(43,717,494)	(2,819,641)	(9,962,334)	(956)		-	
- Customer		22,822	-	-	-	-	-	22,822		-	
- Commodity		(161,586,805)	(83,742,040)	(1,737,518)	(57,734,432)	(3,920,203)	(13,451,436)	(1,221)		(999,809)	
Total		(343,904,419)	(207,800,334)	(3,519,119)	(101,451,926)	(6,739,844)	(23,413,770)	20,645		(999,809)	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
Rate Base Adjustment											
Adjustment											
AMI		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
Delayed Recognition Pension & OPEB		(12,697,212)									PAY-PRI
- Demand	PAY-PRI-D	(6,729,336)	(4,578,440)	(65,751)	(1,613,418)	(104,060)	(367,666)	-		-	53%
- Customer	PAY-PRI-C	(4,488)	-	-	-	-	-	(4,488)		-	0%
- Commodity	PAY-PRI-E	(5,963,389)	(3,090,540)	(64,124)	(2,130,717)	(144,677)	(496,432)	-		(36,898)	47%
Total		(12,697,212)	(7,668,981)	(129,875)	(3,744,136)	(248,737)	(864,097)	(4,488)		(36,898)	
Total Rate Base Adjustment		(12,697,212)									
- Demand		(6,729,336)	(4,578,440)	(65,751)	(1,613,418)	(104,060)	(367,666)	-		-	
- Customer		(4,488)	-	-	-	-	-	(4,488)		-	
- Commodity		(5,963,389)	(3,090,540)	(64,124)	(2,130,717)	(144,677)	(496,432)	-		(36,898)	
Total		(12,697,212)	(7,668,981)	(129,875)	(3,744,136)	(248,737)	(864,097)	(4,488)		(36,898)	
Total Rate Base		**1,047,606,020**									
- Demand		**554,192,731**	**374,823,915**	**5,382,847**	**132,085,988**	**8,519,131**	**30,099,730**	**2,927,159**		**-**	
- Customer		**18,334**	**-**	**-**	**-**	**-**	**-**	**18,334**		**-**	
- Commodity		**493,394,955**	**253,533,266**	**5,260,423**	**174,793,914**	**11,868,613**	**40,724,903**	**3,741,010**		**3,026,974**	
Total		**1,047,606,020**	**628,357,181**	**10,643,270**	**306,879,902**	**20,387,744**	**70,824,634**	**6,686,503**		**3,026,974**	
OPERATIONS & MAINTENANCE EXPENSES											
Distribution Expenses											
Operations Expenses											
(580) Operation Supervision & Engineering		160,905									AE-PRI
- Demand	DMD-PRI	85,307	58,041	834	20,453	1,319	4,661	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	75,598	39,179	813	27,011	1,834	6,293	-		468	47%
Total		160,905	97,219	1,646	47,464	3,153	10,954	-		468	
(581) Load Dispatching		1,446,055									AE-PRI
- Demand	DMD-PRI	766,659	521,612	7,491	183,813	11,855	41,887	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	679,396	352,099	7,306	242,748	16,483	56,557	-		4,204	47%
Total		1,446,055	873,711	14,796	426,561	28,338	98,445	-		4,204	
(582) Station Expenses		304,563									AE-PRI
- Demand	DMD-PRI	161,471	109,860	1,578	38,714	2,497	8,822	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	143,092	74,158	1,539	51,127	3,472	11,912	-		885	47%
Total		304,563	184,018	3,116	89,841	5,968	20,734	-		885	
(583) Overhead line expenses		520,027									AE-PRI
- Demand	DMD-PRI	275,704	187,581	2,694	66,103	4,263	15,063	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	244,323	126,621	2,627	87,296	5,927	20,339	-		1,512	47%
Total		520,027	314,202	5,321	153,399	10,191	35,402	-		1,512	
(584) Underground line expenses		1,987,209									AE-PRI
- Demand	DMD-PRI	1,053,564	716,813	10,294	252,601	16,292	57,563	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	933,645	483,864	10,039	333,591	22,651	77,723	-		5,777	47%
Total		1,987,209	1,200,677	20,334	586,192	38,943	135,285	-		5,777	
(585) Street lighting and signal system expenses		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(586) Meter expenses		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(587) Customer installations expenses		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(588) Miscellaneous distribution expenses		10,411,015									DISTPLT-PRI
- Demand	DISTPLT-PRI-D	5,519,636	3,755,396	53,931	1,323,382	85,354	301,572	-		-	53%
- Customer	DISTPLT-PRI-C	-	-	-	-	-	-	-		-	0%
- Commodity	DISTPLT-PRI-E	4,891,379	2,534,969	52,597	1,747,688	118,669	407,191	-		30,265	47%
Total		10,411,015	6,290,365	106,528	3,071,070	204,023	708,763	-		30,265	
(589) Rents		1,555,245									AE-PRI
- Demand	DMD-PRI	824,548	560,998	8,056	197,693	12,751	45,050	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	730,697	378,685	7,857	261,078	17,727	60,828	-		4,521	47%
Total		1,555,245	939,684	15,914	458,771	30,478	105,878	-		4,521	
Total Dist. Operations Expenses		16,385,019									
- Demand		8,686,889	5,910,302	84,878	2,082,759	134,331	474,619	-		-	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		7,698,129	3,989,574	82,777	2,750,539	186,763	640,843	-		47,632	
Total		16,385,019	9,899,876	167,655	4,833,299	321,095	1,115,462	-		47,632	
Maintenance Expense											
(590) Maintenance Supervision and Engineering		1,242,451									AE-PRI
- Demand	DMD-PRI	658,713	448,169	6,436	157,932	10,186	35,990	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	583,737	302,523	6,277	208,569	14,162	48,594	-		3,612	47%
Total		1,242,451	750,692	12,713	366,502	24,348	84,584	-		3,612	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	Lighting LTG	Classification Factor
(591) Maintenance of Structures		50,499								AE-PRI
- Demand	DMD-PRI	26,773	18,216	262	6,419	414	1,463	-	-	53%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-PRI	23,726	12,296	255	8,477	576	1,975	-	147	47%
Total		50,499	30,512	517	14,896	990	3,438	-	147	
(592) Maintenance of Station Equipment		5,986,956								AE-PRI
- Demand	DMD-PRI	3,174,121	2,159,577	31,014	761,024	49,084	173,422	-	-	53%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-PRI	2,812,835	1,457,759	30,246	1,005,025	68,242	234,159	-	17,404	47%
Total		5,986,956	3,617,336	61,260	1,766,049	117,325	407,581	-	17,404	
(593) Maintenance of Overhead Lines		42,114,302								AE-PRI
- Demand	DMD-PRI	22,327,853	15,191,209	218,161	5,353,302	345,271	1,219,910	-	-	53%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-PRI	19,786,449	10,254,375	212,762	7,069,693	480,036	1,647,154	-	122,429	47%
Total		42,114,302	25,445,583	430,923	12,422,995	825,308	2,867,064	-	122,429	
(594) Maintenance of underground lines		2,286,373								AE-PRI
- Demand	DMD-PRI	1,212,173	824,726	11,844	290,629	18,745	66,229	-	-	53%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-PRI	1,074,201	556,707	11,551	383,812	26,061	89,424	-	6,647	47%
Total		2,286,373	1,381,433	23,395	674,441	44,806	155,652	-	6,647	
(595) Maintenance of line transformers		-								#N/A
- Demand		-	-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	-	
(596) Maintenance of street lighting and signal systems		-								#N/A
- Demand		-	-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	-	
(597) Maintenance of meters		-								#N/A
- Demand		-	-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	-	
(598) Maintenance of miscellaneous distribution plant		1,161,127								DISTPLT-PRI
- Demand	DISTPLT-PRI-D	615,598	418,835	6,015	147,595	9,519	33,634	-	-	53%
- Customer	DISTPLT-PRI-C	-	-	-	-	-	-	-	-	0%
- Commodity	DISTPLT-PRI-E	545,529	282,722	5,866	194,917	13,235	45,413	-	3,375	47%
Total		1,161,127	701,556	11,881	342,513	22,754	79,047	-	3,375	
Total Dist. Maintenance Expenses		52,841,708								
- Demand		28,015,231	19,060,732	273,731	6,716,902	433,219	1,530,646	-	-	
- Customer		-	-	-	-	-	-	-	-	
- Commodity		24,826,478	12,866,381	266,958	8,870,493	602,312	2,066,719	-	153,614	
Total		52,841,708	31,927,113	540,689	15,587,396	1,035,531	3,597,366	-	153,614	
Total Distribution Expenses		69,226,727								
- Demand		36,702,120	24,971,033	358,609	8,799,662	567,550	2,005,265	-	-	
- Customer		-	-	-	-	-	-	-	-	
- Commodity		32,524,607	16,855,955	349,735	11,621,033	789,075	2,707,562	-	201,246	
Total		69,226,727	41,826,989	708,344	20,420,694	1,356,626	4,712,828	-	201,246	
Customer Account Expense										
(901) Supervision		-								#N/A
- Demand		-	-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	-	
(902) Meter reading expenses		-								#N/A
- Demand		-	-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	-	
(903) Customer records and collection expenses		-								#N/A
- Demand		-	-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	-	
(904) Uncollectible accounts		-								#N/A
- Demand		-	-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	-	
(905) Miscellaneous customer accounts expenses		-								#N/A
- Demand		-	-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	-	
Total Customer Account Expenses		-								
- Demand		-	-	-	-	-	-	-	-	
- Customer		-	-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	-	
Total		-	-	-	-	-	-	-	-	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
Customer Service Expenses											
(907) Customer Service Supervision		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(908) Customer Assistance		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(909) Informational and instructional advertising		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(910) Miscellaneous customer service and informational		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
Total Customer Service Expenses		-									
- Demand		-	-	-	-	-	-	-		-	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		-	-	-	-	-	-	-		-	
Total		-	-	-	-	-	-	-		-	
Sales Expenses											
(911) Sales Exp		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
Total Sales Expenses		-									
- Demand		-	-	-	-	-	-	-		-	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		-	-	-	-	-	-	-		-	
Total		-	-	-	-	-	-	-		-	
Administrative & General Expense											
Labor Related											
(920) Administrative and general salaries		4,748,544									AE-PRI-GTA&G
- Demand	DMD-PRI	2,514,302	1,710,657	24,567	602,826	38,880	137,372	-		-	53%
- Customer	CUST-GTA&G	6,123	-	-	-	-	-	6,123		-	0%
- Commodity	NRG-PRI	2,228,119	1,154,728	23,959	796,106	54,056	185,483	-		13,786	47%
Total		4,748,544	2,865,385	48,526	1,398,933	92,937	322,855	6,123		13,786	
(921) Office supplies and expenses		424,763									AE-PRI-GTA&G
- Demand	DMD-PRI	224,907	153,020	2,198	53,924	3,478	12,288	-		-	53%
- Customer	CUST-GTA&G	548	-	-	-	-	-	548		-	0%
- Commodity	NRG-PRI	199,308	103,292	2,143	71,213	4,835	16,592	-		1,233	47%
Total		424,763	256,312	4,341	125,136	8,313	28,880	548		1,233	
(922) Administrative expenses transferred—Credit		(422,901)									AE-PRI-GTA&G
- Demand	DMD-PRI	(223,921)	(152,349)	(2,188)	(53,687)	(3,463)	(12,234)	-		-	53%
- Customer	CUST-GTA&G	(545)	-	-	-	-	-	(545)		-	0%
- Commodity	NRG-PRI	(198,434)	(102,839)	(2,134)	(70,900)	(4,814)	(16,519)	-		(1,228)	47%
Total		(422,901)	(255,188)	(4,322)	(124,588)	(8,277)	(28,753)	(545)		(1,228)	
(923) Outside services employed		15,466,909									AE-PRI-GTA&G
- Demand	DMD-PRI	8,189,559	5,571,933	80,019	1,963,520	126,641	447,447	-		-	53%
- Customer	CUST-GTA&G	19,943	-	-	-	-	-	19,943		-	0%
- Commodity	NRG-PRI	7,257,406	3,761,168	78,038	2,593,069	176,071	604,154	-		44,905	47%
Total		15,466,909	9,333,102	158,057	4,556,589	302,712	1,051,601	19,943		44,905	
(926) Employee pensions and benefits		(954,943)									AE-PRI-GTA&G
- Demand	DMD-PRI	(505,632)	(344,017)	(4,940)	(121,230)	(7,819)	(27,626)	-		-	53%
- Customer	CUST-GTA&G	(1,231)	-	-	-	-	-	(1,231)		-	0%
- Commodity	NRG-PRI	(448,080)	(232,219)	(4,818)	(160,099)	(10,871)	(37,301)	-		(2,772)	47%
Total		(954,943)	(576,236)	(9,759)	(281,329)	(18,690)	(64,927)	(1,231)		(2,772)	
(426) Pension / OPEB Non-Service Cost		-									AE-PRI-GTA&G
- Demand		-	-	-	-	-	-	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity		-	-	-	-	-	-	-		-	47%
Total		-	-	-	-	-	-	-		-	
(924) Property insurance		92,710									AE-PRI-GTA&G
- Demand	DMD-PRI	49,089	33,399	480	11,769	759	2,682	-		-	53%
- Customer	CUST-GTA&G	120	-	-	-	-	-	120		-	0%
- Commodity	NRG-PRI	43,501	22,545	468	15,543	1,055	3,621	-		269	47%
Total		92,710	55,943	947	27,313	1,814	6,303	120		269	
(925) Injuries and damages		1,693,235									AE-PRI-GTA&G
- Demand	DMD-PRI	896,549	609,986	8,760	214,956	13,864	48,984	-		-	53%
- Customer	CUST-GTA&G	2,183	-	-	-	-	-	2,183		-	0%
- Commodity	NRG-PRI	794,502	411,753	8,543	283,875	19,275	66,140	-		4,916	47%
Total		1,693,235	1,021,738	17,303	498,831	33,139	115,124	2,183		4,916	
(935) Maintenance of general plant		1,514,529									AE-PRI-GTA&G
- Demand	DMD-PRI	801,926	545,607	7,835	192,269	12,401	43,814	-		-	53%
- Customer	CUST-GTA&G	1,953	-	-	-	-	-	1,953		-	0%
- Commodity	NRG-PRI	710,649	368,296	7,642	253,915	17,241	59,159	-		4,397	47%
Total		1,514,529	913,903	15,477	446,184	29,642	102,973	1,953		4,397	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
(929) Duplicate charges—Credit		-									AE-PRI-GTA&G
- Demand		-	-	-	-	-	-	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity		-	-	-	-	-	-	-		-	47%
Total		-	-	-	-	-	-	-		-	
(928) Regulatory commission expenses		1,698,261									AE-PRI-GTA&G
- Demand	DMD-PRI	899,211	611,796	8,786	215,594	13,905	49,129	-		-	53%
- Customer	CUST-GTA&G	2,190	-	-	-	-	-	2,190		-	0%
- Commodity	NRG-PRI	796,861	412,975	8,569	284,718	19,333	66,336	-		4,931	47%
Total		1,698,261	1,024,771	17,355	500,312	33,238	115,465	2,190		4,931	
(930.1) Gen Advertising Exp		272,417									AE-PRI-GTA&G
- Demand	DMD-PRI	144,242	98,138	1,409	34,583	2,231	7,881	-		-	53%
- Customer	CUST-GTA&G	351	-	-	-	-	-	351		-	0%
- Commodity	NRG-PRI	127,824	66,245	1,374	45,671	3,101	10,641	-		791	47%
Total		272,417	164,383	2,784	80,255	5,332	18,522	351		791	
(930.2) Misc Gen Exp		852,947									AE-PRI-GTA&G
- Demand	DMD-PRI	451,626	307,273	4,413	108,281	6,984	24,675	-		-	53%
- Customer	CUST-GTA&G	1,100	-	-	-	-	-	1,100		-	0%
- Commodity	NRG-PRI	400,221	207,415	4,304	142,999	9,710	33,317	-		2,476	47%
Total		852,947	514,688	8,716	251,280	16,694	57,992	1,100		2,476	
(931) Rents		755,211									AE-PRI-GTA&G
- Demand	DMD-PRI	399,876	272,064	3,907	95,874	6,184	21,848	-		-	53%
- Customer	CUST-GTA&G	974	-	-	-	-	-	974		-	0%
- Commodity	NRG-PRI	354,361	183,648	3,810	126,613	8,597	29,499	-		2,193	47%
Total		755,211	455,712	7,718	222,487	14,781	51,347	974		2,193	
(932) Institutional Ad - Newspaper		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(933) Transportation expenses		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total A&G Expense		26,141,681									
- Demand		13,841,734	9,417,505	135,245	3,318,680	214,044	756,260	-		-	
- Customer		33,707	-	-	-	-	-	33,707		-	
- Commodity		12,266,239	6,357,008	131,898	4,382,724	297,590	1,021,123	-		75,897	
Total		26,141,681	15,774,513	267,143	7,701,403	511,634	1,777,383	33,707		75,897	
O&M Adjustment											
Adjustment											
Int on Cust Deposits		-									CUS
- Demand		-	-	-	-	-	-	-		-	0%
- Customer	CUST-DEP	-	-	-	-	-	-	-		-	100%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		-	-	-	-	-	-	-		-	
Annualize Payroll Increase		1,839,145									PAY-PRI
- Demand	PAY-PRI-D	974,720	663,170	9,524	233,698	15,073	53,255	-		-	53%
- Customer	PAY-PRI-C	650	-	-	-	-	-	650		-	0%
- Commodity	PAY-PRI-E	863,775	447,654	9,288	308,627	20,956	71,906	-		5,345	47%
Total		1,839,145	1,110,824	18,812	542,324	36,029	125,161	650		5,345	
Svngs Pln Match on Payroll Inc		55,174									PAY-PRI
- Demand	PAY-PRI-D	29,242	19,895	286	7,011	452	1,598	-		-	53%
- Customer	PAY-PRI-C	20	-	-	-	-	-	20		-	0%
- Commodity	PAY-PRI-E	25,913	13,430	279	9,259	629	2,157	-		160	47%
Total		55,174	33,325	564	16,270	1,081	3,755	20		160	
Reclass Amortization of Net Loss on Reacquired Debt		208,932									DISTPLT-PRI
- Demand	DISTPLT-PRI-D	110,770	75,365	1,082	26,558	1,713	6,052	-		-	53%
- Customer	DISTPLT-PRI-C	-	-	-	-	-	-	-		-	0%
- Commodity	DISTPLT-PRI-E	98,162	50,873	1,056	35,073	2,381	8,172	-		607	47%
Total		208,932	126,237	2,138	61,631	4,094	14,224	-		607	
BPU & RPA Assessments		295,625									DIST-REV
- Demand	DIST-REV-DMD	78,072	-	-	50,448	3,979	9,816	7,295		6,394	26%
- Customer	DIST-REV-CUST	23,804	16,978	518	5,830	49	191	236		-	8%
- Commodity	DIST-REV-NRG	193,750	143,906	2,662	39,305	980	2,524	1,910		2,463	66%
Total		295,625	160,884	3,180	95,582	5,009	12,531	9,441		8,857	
Rate Case Exp		-									AE-ALL
- Demand	DMD-ALL	-	-	-	-	-	-	-		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	-	-	-	-	-	-	-		-	48%
Total		-	-	-	-	-	-	-		-	
Pension Smoothing		5,029,098									PAY-PRI
- Demand	PAY-PRI-D	2,665,348	1,813,424	26,043	639,041	41,216	145,625	-		-	53%
- Customer	PAY-PRI-C	1,778	-	-	-	-	-	1,778		-	0%
- Commodity	PAY-PRI-E	2,361,972	1,224,098	25,398	843,932	57,304	196,626	-		14,615	47%
Total		5,029,098	3,037,522	51,441	1,482,973	98,520	342,251	1,778		14,615	
OPEB Smoothing		1,725,691									PAY-PRI
- Demand	PAY-PRI-D	914,591	622,260	8,936	219,281	14,143	49,970	-		-	53%
- Customer	PAY-PRI-C	610	-	-	-	-	-	610		-	0%
- Commodity	PAY-PRI-E	810,490	420,038	8,715	289,588	19,663	67,471	-		5,015	47%
Total		1,725,691	1,042,299	17,651	508,869	33,806	117,440	610		5,015	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
Normalize Vegetation Management Expense		4,138,329									OHPLT-PRI
- Demand	OHPLT-PRI-D	2,194,029	1,492,752	21,437	526,038	33,928	119,873	-		-	53%
- Customer	OHPLT-PRI-C	-	-	-	-	-	-	-		-	0%
- Commodity	OHPLT-PRI-E	1,944,300	1,007,638	20,907	694,698	47,170	161,856	-		12,030	47%
Total		4,138,329	2,500,390	42,344	1,220,736	81,098	281,730	-		12,030	
ServCo Depr @ JCP&L Rates		614,014									AE-ALL
- Demand	DMD-ALL	317,928	202,274	2,905	71,280	4,597	16,243	18,403		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	296,086	139,805	2,901	96,386	6,545	22,457	23,520		1,669	48%
Total		614,014	342,079	5,806	167,666	11,142	38,700	41,924		1,669	
SERP/EDCP		1,731,555									PAY-PRI
- Demand	PAY-PRI-D	917,699	624,375	8,967	220,026	14,191	50,140	-		-	53%
- Customer	PAY-PRI-C	612	-	-	-	-	-	612		-	0%
- Commodity	PAY-PRI-E	813,244	421,466	8,745	290,572	19,730	67,700	-		5,032	47%
Total		1,731,555	1,045,841	17,711	510,598	33,921	117,839	612		5,032	
Advertising removal		(746,134)									AE-PRI-GTA&G
- Demand	DMD-PRI	(395,070)	(268,794)	(3,860)	(94,722)	(6,109)	(21,585)	-		-	53%
- Customer	CUST-GTA&G	(962)	-	-	-	-	-	(962)		-	0%
- Commodity	NRG-PRI	(350,102)	(181,441)	(3,765)	(125,091)	(8,494)	(29,145)	-		(2,166)	47%
Total		(746,134)	(450,235)	(7,625)	(219,813)	(14,603)	(50,730)	(962)		(2,166)	
BGS Administrative Labor included in BGS Deferral		(102,860)									AE-ALL
- Demand	DMD-ALL	(53,259)	(33,885)	(487)	(11,941)	(770)	(2,721)	(3,083)		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(49,600)	(23,420)	(486)	(16,147)	(1,096)	(3,762)	(3,940)		(280)	48%
Total		(102,860)	(57,305)	(973)	(28,087)	(1,867)	(6,483)	(7,023)		(280)	
Low Income O&M		882,435									AE-ALL
- Demand	DMD-ALL	456,913	290,699	4,175	102,441	6,607	23,344	26,449		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	425,522	200,922	4,169	138,522	9,406	32,274	33,802		2,399	48%
Total		882,435	491,621	8,344	240,963	16,013	55,618	60,251		2,399	
Contract Labor/Fuel Costs		81,460									AE-PRI-GTA&G
- Demand	DMD-PRI	43,132	29,346	421	10,341	667	2,357	-		-	53%
- Customer	CUST-GTA&G	105	-	-	-	-	-	105		-	0%
- Commodity	NRG-PRI	38,223	19,809	411	13,657	927	3,182	-		237	47%
Total		81,460	49,155	832	23,998	1,594	5,538	105		237	
Total O&M Adjustment		15,752,464									
- Demand		8,254,113	5,530,881	79,429	1,999,501	129,687	453,966	49,064		6,394	
- Customer		26,616	16,978	518	5,830	49	191	3,048		-	
- Commodity		7,471,735	3,884,777	80,279	2,618,380	176,101	603,418	55,293		47,126	
Total		15,752,464	9,432,636	160,226	4,623,711	305,838	1,057,575	107,405		53,519	
Total O&M Expenses		111,120,872									
- Demand		58,797,968	39,919,420	573,283	14,117,843	911,282	3,215,492	49,064		6,394	
- Customer		60,324	16,978	518	5,830	49	191	36,756		-	
- Commodity		52,262,580	27,097,740	561,912	18,622,136	1,262,766	4,332,103	55,293		324,269	
Total		**111,120,872**	**67,034,138**	**1,135,713**	**32,745,809**	**2,174,097**	**7,547,786**	**141,112**		**330,663**	
DEPRECIATION EXPENSE											
Depreciation Expense											
(403-360) Land & Land Rights		66,658									AE-PRI
- Demand	DMD-PRI	35,340	24,044	345	8,473	546	1,931	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	31,318	16,230	337	11,190	760	2,607	-		194	47%
Total		66,658	40,275	682	19,663	1,306	4,538	-		194	
(403-361) Struct & Impmnts		526,520									AE-PRI
- Demand	DMD-PRI	279,147	189,923	2,727	66,928	4,317	15,252	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	247,374	128,202	2,660	88,387	6,002	20,593	-		1,531	47%
Total		526,520	318,125	5,387	155,314	10,318	35,845	-		1,531	
(403-362) Station Equip		4,393,098									AE-PRI
- Demand	DMD-PRI	2,329,100	1,584,651	22,757	558,423	36,017	127,253	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	2,063,997	1,069,672	22,194	737,466	50,074	171,821	-		12,771	47%
Total		4,393,098	2,654,322	44,951	1,295,888	86,091	299,074	-		12,771	
(403-364) Poles, Towers & Fixt		9,069,659									AE-PRI
- Demand	DMD-PRI	4,808,486	3,271,551	46,983	1,152,877	74,357	262,717	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	4,261,174	2,208,363	45,820	1,522,516	103,380	354,728	-		26,366	47%
Total		9,069,659	5,479,914	92,803	2,675,394	177,737	617,446	-		26,366	
(403-365) OH Cond & Dev		20,988,905									AE-PRI
- Demand	DMD-PRI	11,127,744	7,570,987	108,727	2,667,976	172,076	607,978	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	9,861,161	5,110,570	106,036	3,523,390	239,240	820,908	-		61,016	47%
Total		20,988,905	12,681,557	214,763	6,191,366	411,316	1,428,886	-		61,016	
(403-366) UG Conduit		990,718									AE-PRI
- Demand	DMD-PRI	525,251	357,366	5,132	125,934	8,122	28,698	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	465,466	241,229	5,005	166,311	11,293	38,748	-		2,880	47%
Total		990,718	598,594	10,137	292,245	19,415	67,446	-		2,880	
(403-367) UG Cond & Dev		6,410,848									AE-PRI
- Demand	DMD-PRI	3,398,856	2,312,481	33,210	814,906	52,559	185,701	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	3,011,991	1,560,972	32,388	1,076,184	73,074	250,738	-		18,637	47%
Total		6,410,848	3,873,453	65,597	1,891,090	125,632	436,439	-		18,637	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	Lighting LTG	Classification Factor
(403-368) Line Transformers		-								#N/A
- Demand		-	-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	-	
(403-369) Services		-								#N/A
- Demand		-	-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	-	
(403-370) Meters		-								#N/A
- Demand		-	-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	-	
(403-371) Install on Cust Premise		-								#N/A
- Demand		-	-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	-	
(403-373) St Lt & Signal Sys		-								#N/A
- Demand		-	-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	-	
(403-374) Asset Ret Costs		-								AE-PRI
- Demand	DMD-PRI	-	-	-	-	-	-	-	-	53%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-PRI	-	-	-	-	-	-	-	-	47%
Total		-	-	-	-	-	-	-	-	
(403-389) Land & Land Rights		143								AE-ALL
- Demand	DMD-ALL	74	47	1	17	1	4	4	-	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	69	33	1	23	2	5	5	0	48%
Total		143	80	1	39	3	9	10	0	
(403-390) Struct & Impmnts -		455,452								AE-ALL
- Demand	DMD-ALL	235,827	150,039	2,155	52,873	3,410	12,049	13,651	-	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	219,625	103,702	2,152	71,495	4,855	16,658	17,446	1,238	48%
Total		455,452	253,741	4,306	124,368	8,265	28,706	31,097	1,238	
(403-391) Office Furn & Equip		2,248,029								AE-ALL
- Demand	DMD-ALL	1,163,999	740,564	10,635	260,971	16,832	59,470	67,379	-	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	1,084,030	511,854	10,620	352,889	23,961	82,219	86,113	6,111	48%
Total		2,248,029	1,252,419	21,255	613,860	40,793	141,689	153,492	6,111	
(403-392) Transportation Equip		522,042								AE-ALL
- Demand	DMD-ALL	270,306	171,975	2,470	60,603	3,909	13,810	15,647	-	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	251,736	118,864	2,466	81,949	5,564	19,093	19,997	1,419	48%
Total		522,042	290,839	4,936	142,552	9,473	32,903	35,644	1,419	
(403-393) Stores Equip		6,830								AE-ALL
- Demand	DMD-ALL	3,536	2,250	32	793	51	181	205	-	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	3,293	1,555	32	1,072	73	250	262	19	48%
Total		6,830	3,805	65	1,865	124	430	466	19	
(403-394) Tools, Shop & Garage Equip		313,574								AE-ALL
- Demand	DMD-ALL	162,364	103,300	1,483	36,402	2,348	8,295	9,399	-	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	151,210	71,398	1,481	49,224	3,342	11,469	12,012	852	48%
Total		313,574	174,698	2,965	85,626	5,690	19,764	21,410	852	
(403-395) Laboratory Equip		6,433								AE-ALL
- Demand	DMD-ALL	3,331	2,119	30	747	48	170	193	-	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	3,102	1,465	30	1,010	69	235	246	17	48%
Total		6,433	3,584	61	1,757	117	405	439	17	
(403-396) Power Operated Equip		19,617								AE-ALL
- Demand	DMD-ALL	10,158	6,463	93	2,277	147	519	588	-	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	9,460	4,467	93	3,079	209	717	751	53	48%
Total		19,617	10,929	185	5,357	356	1,236	1,339	53	
(403-397) Communication Equip		1,110,157								AE-ALL
- Demand	DMD-ALL	574,824	365,717	5,252	128,877	8,312	29,368	33,274	-	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	535,333	252,772	5,245	174,269	11,833	40,603	42,525	3,018	48%
Total		1,110,157	618,489	10,497	303,146	20,145	69,971	75,800	3,018	
(403-398) MISC Equip		(5,809)								AE-ALL
- Demand	DMD-ALL	(3,008)	(1,914)	(27)	(674)	(43)	(154)	(174)	-	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	(2,801)	(1,323)	(27)	(912)	(62)	(212)	(223)	(16)	48%
Total		(5,809)	(3,237)	(55)	(1,586)	(105)	(366)	(397)	(16)	
Total Depreciation Expense		47,122,873								
- Demand		24,925,337	16,851,564	242,005	5,938,403	383,008	1,353,242	140,165	-	
- Customer		-	-	-	-	-	-	-	-	
- Commodity		22,197,536	11,400,024	236,533	7,859,540	533,668	1,831,179	179,136	136,107	
Total		47,122,873	28,251,588	478,538	13,797,943	916,676	3,184,422	319,301	136,107	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	Lighting LTG	Classification Factor
Depreciation Adjustment										
Adjustment										
Annualize Deprec Exp		3,142,011								DPR-TOT-PRI
- Demand	DPR-TOT-PRI-D	1,661,946	1,123,611	16,136	395,955	25,538	90,230	9,346	-	53%
- Customer	DPR-TOT-PRI-C	-	-	-	-	-	-	-	-	0%
- Commodity	DPR-TOT-PRI-E	1,480,065	760,119	15,771	524,050	35,583	122,098	11,944	9,075	47%
Total		3,142,011	1,883,731	31,907	920,005	61,121	212,328	21,290	9,075	
Average Net Salvage		1,452,920								DISTPLT-PRI
- Demand	DISTPLT-PRI-D	770,298	524,088	7,526	184,686	11,912	42,086	-	-	53%
- Customer	DISTPLT-PRI-C	-	-	-	-	-	-	-	-	0%
- Commodity	DISTPLT-PRI-E	682,621	353,770	7,340	243,900	16,561	56,826	-	4,224	47%
Total		1,452,920	877,858	14,867	428,586	28,473	98,912	-	4,224	
Total Depreciation Adjustment		4,594,931								
- Demand		2,432,245	1,647,700	23,663	580,641	37,450	132,316	9,346	-	
- Customer		-	-	-	-	-	-	-	-	
- Commodity		2,162,686	1,113,889	23,111	767,951	52,144	178,923	11,944	13,299	
Total		4,594,931	2,761,589	46,774	1,348,592	89,594	311,240	21,290	13,299	
Total Depreciation Expense										
- Demand		27,357,582	18,499,264	265,668	6,519,044	420,458	1,485,558	149,511	-	
- Customer		-	-	-	-	-	-	-	-	
- Commodity		24,360,222	12,513,914	259,644	8,627,491	585,812	2,010,103	191,080	149,406	
Total		**51,717,804**	**31,013,177**	**525,312**	**15,146,535**	**1,006,270**	**3,495,661**	**340,591**	**149,406**	
Amortization, Accretion, Regulatory Debits and Credits										
Amort - Ltd Term Elec Prpty		4,209,061								DISTPLT-PRI
- Demand	DISTPLT-PRI-D	2,231,529	1,518,266	21,804	535,029	34,508	121,922	-	-	53%
- Customer	DISTPLT-PRI-C	-	-	-	-	-	-	-	-	0%
- Commodity	DISTPLT-PRI-E	1,977,532	1,024,861	21,264	706,572	47,977	164,623	-	12,236	47%
Total		4,209,061	2,543,127	43,068	1,241,601	82,484	286,545	-	12,236	
Accretion Expense		136,563								AE-ALL
- Demand	DMD-ALL	70,711	44,988	646	15,853	1,022	3,613	4,093	-	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	65,853	31,094	645	21,437	1,456	4,995	5,231	371	48%
Total		136,563	76,082	1,291	37,291	2,478	8,607	9,324	371	
Regulatory Debits		22,140,546								AE-ALL
- Demand	DMD-ALL	11,464,077	7,293,723	104,745	2,570,270	165,774	585,713	663,606	-	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	10,676,469	5,041,186	104,597	3,475,554	235,992	809,763	848,112	60,188	48%
Total		22,140,546	12,334,909	209,342	6,045,824	401,767	1,395,475	1,511,718	60,188	
Regulatory Credits		9,222								AE-ALL
- Demand	DMD-ALL	4,775	3,038	44	1,071	69	244	276	-	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	4,447	2,100	44	1,448	98	337	353	25	48%
Total		9,222	5,138	87	2,518	167	581	630	25	
Total Depreciation and Amortization		78,213,196								
- Demand		41,128,674	27,359,279	392,907	9,641,267	621,831	2,197,050	817,487	-	
- Customer		-	-	-	-	-	-	-	-	
- Commodity		37,084,523	18,613,154	386,194	12,832,502	871,335	2,989,820	1,044,776	222,225	
Total		**78,213,196**	**45,972,433**	**779,101**	**22,473,769**	**1,493,166**	**5,186,870**	**1,862,263**	**222,225**	
TAXES										
Taxes Other than Income										
(408) Payroll Taxes		1,247,629								PAY-PRI
- Demand	PAY-PRI-D	661,225	449,878	6,461	158,535	10,225	36,127	-	-	53%
- Customer	PAY-PRI-C	441	-	-	-	-	-	441	-	0%
- Commodity	PAY-PRI-E	585,963	303,677	6,301	209,364	14,216	48,779	-	3,626	47%
Total		1,247,629	753,555	12,762	367,899	24,441	84,906	441	3,626	
(408) Property Taxes		1,817,787								RB-PRI
- Demand	RB-PRI-D	961,625	650,388	9,340	229,193	14,782	52,228	5,079	-	53%
- Customer	RB-PRI-C	32	-	-	-	-	-	32	-	0%
- Commodity	RB-PRI-E	856,130	439,926	9,128	303,299	20,594	70,665	6,491	5,252	47%
Total		1,817,787	1,090,314	18,468	532,492	35,376	122,894	11,602	5,252	
Total Taxes Other than Income		3,065,416								
- Demand		1,622,850	1,100,266	15,801	387,728	25,007	88,355	5,079	-	
- Customer		473	-	-	-	-	-	473	-	
- Commodity		1,442,093	743,603	15,429	512,664	34,810	119,445	6,491	8,878	
Total Taxes Other than Income		**3,065,416**	**1,843,869**	**31,230**	**900,392**	**59,817**	**207,800**	**12,043**	**8,878**	
Total Expenses		**192,399,484**								
- Demand		**101,549,492**	**68,378,965**	**981,990**	**24,146,837**	**1,558,121**	**5,500,897**	**871,630**	**6,394**	
- Customer		**60,796**	**16,978**	**518**	**5,830**	**49**	**191**	**37,228**	**-**	
- Commodity		**90,789,196**	**46,454,497**	**963,535**	**31,967,302**	**2,168,911**	**7,441,368**	**1,106,560**	**555,372**	
Total		**192,399,484**	**114,850,440**	**1,946,043**	**56,119,969**	**3,727,081**	**12,942,456**	**2,015,418**	**561,766**	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
REVENUE REQUIREMENT CALCULATION											
Total Rate Base											
- Demand		554,192,731	374,823,915	5,382,847	132,085,988	8,519,131	30,099,730	2,927,159		-	
- Customer		18,334	-	-	-	-	-	18,334		-	
- Commodity		493,394,955	253,533,266	5,260,423	174,793,914	11,868,613	40,724,903	3,741,010		3,026,974	
Total		1,047,606,020	628,357,181	10,643,270	306,879,902	20,387,744	70,824,634	6,686,503		3,026,974	
Required Net Income											
- Demand		42,118,648	28,486,618	409,096	10,038,535	647,454	2,287,580	222,464		-	
- Customer		1,393	-	-	-	-	-	1,393		-	
- Commodity		37,498,017	19,268,528	399,792	13,284,337	902,015	3,095,093	284,317		230,050	
Total		79,618,058	47,755,146	808,889	23,322,873	1,549,469	5,382,672	508,174		230,050	
Interest Synchronization											
- Demand		12,187,430	8,242,873	118,376	2,904,745	187,347	661,933	64,372		-	
- Customer		403	-	-	-	-	-	403		-	
- Commodity		10,850,406	5,575,531	115,684	3,843,949	261,006	895,594	82,270		66,567	
Total		23,038,239	13,818,404	234,060	6,748,694	448,353	1,557,527	147,045		66,567	
Net Income Before Income Taxes											
- Demand		29,931,218	20,243,745	290,720	7,133,790	460,107	1,625,647	158,092		-	
- Customer		990	-	-	-	-	-	990		-	
- Commodity		26,647,610	13,692,997	284,109	9,440,389	641,008	2,199,498	202,047		163,483	
Total		56,579,818	33,936,742	574,829	16,574,178	1,101,115	3,825,145	361,129		163,483	
Taxable Income											
- Demand		41,634,745	28,159,334	404,396	9,923,202	640,015	2,261,297	219,908		-	
- Customer		1,377	-	-	-	-	-	1,377		-	
- Commodity		37,067,200	19,047,151	395,199	13,131,713	891,651	3,059,533	281,050		227,407	
Total		78,703,322	47,206,485	799,595	23,054,915	1,531,667	5,320,830	502,336		227,407	
NJ State Corporate Business Tax											
- Demand		3,747,127	2,534,340	36,396	893,088	57,601	203,517	19,792		-	
- Customer		124	-	-	-	-	-	124		-	
- Commodity		3,336,048	1,714,244	35,568	1,181,854	80,249	275,358	25,295		20,467	
Total		7,083,299	4,248,584	71,964	2,074,942	137,850	478,875	45,210		20,467	
Federal Taxable Income											
- Demand		37,887,618	25,624,994	368,001	9,030,114	582,414	2,057,781	200,116		-	
- Customer		1,253	-	-	-	-	-	1,253		-	
- Commodity		33,731,152	17,332,908	359,631	11,949,859	811,403	2,784,175	255,756		206,940	
Total		71,620,023	42,957,901	727,632	20,979,973	1,393,817	4,841,956	457,126		206,940	
Federal Income Tax											
- Demand		7,956,400	5,381,249	77,280	1,896,324	122,307	432,134	42,024		-	
- Customer		263	-	-	-	-	-	263		-	
- Commodity		7,083,542	3,639,911	75,523	2,509,470	170,395	584,677	53,709		43,457	
Total		15,040,205	9,021,159	152,803	4,405,794	292,701	1,016,811	95,996		43,457	
NJ Federal & State Income Tax		22,123,504									
- Demand		11,703,527	7,915,589	113,676	2,789,412	179,908	635,651	61,816		-	
- Customer		387	-	-	-	-	-	387		-	
- Commodity		10,419,590	5,354,154	111,090	3,691,325	250,643	860,035	79,003		63,924	
Total		22,123,504	13,269,743	224,766	6,480,737	430,551	1,495,685	141,207		63,924	
Tax Reform Amortization		(3,245,508)									RB-PRI
- Demand	RB-PRI-D	(1,716,902)	(1,161,213)	(16,676)	(409,206)	(26,392)	(93,250)	(9,068)		-	53%
- Customer	RB-PRI-C	(57)	-	-	-	-	-	(57)		-	0%
- Commodity	RB-PRI-E	(1,528,549)	(785,452)	(16,297)	(541,516)	(36,769)	(126,167)	(11,590)		(9,378)	47%
Total		(3,245,508)	(1,946,665)	(32,973)	(950,721)	(63,162)	(219,416)	(20,715)		(9,378)	
Investment Tax Credit		(47,332)									RB-PRI
- Demand	RB-PRI-D	(25,039)	(16,935)	(243)	(5,968)	(385)	(1,360)	(132)		-	53%
- Customer	RB-PRI-C	(1)	-	-	-	-	-	(1)		-	0%
- Commodity	RB-PRI-E	(22,292)	(11,455)	(238)	(7,897)	(536)	(1,840)	(169)		(137)	47%
Total		(47,332)	(28,390)	(481)	(13,865)	(921)	(3,200)	(302)		(137)	
Federal & State Income Taxes											
- Demand		9,961,586	6,737,440	96,756	2,374,239	153,131	541,041	52,616		-	
- Customer		330	-	-	-	-	-	330		-	
- Commodity		8,868,749	4,557,247	94,556	3,141,912	213,338	732,028	67,244		54,410	
Total		18,830,664	11,294,688	191,312	5,516,150	366,469	1,273,069	120,190		54,410	
Revenue Requirement											
- Demand		**153,629,725**	**103,603,023**	**1,487,843**	**36,559,611**	**2,358,706**	**8,329,518**	**1,146,710**		**6,394**	
- Customer		**62,519**	**16,978**	**518**	**5,830**	**49**	**191**	**38,951**		**-**	
- Commodity		**137,155,962**	**70,280,273**	**1,457,883**	**48,393,551**	**3,284,263**	**11,268,488**	**1,458,121**		**839,832**	
Total		**290,848,206**	**173,900,273**	**2,946,244**	**84,958,992**	**5,643,018**	**19,598,197**	**2,643,782**		**846,226**	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG	Classification Factor
UTILITY PLANT											
Intangible Plant											
(301) Organizational Costs		29,589									AE-ALL
- Demand	DMD-ALL	15,321	9,747	140	3,435	222	783	887		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	14,268	6,737	140	4,645	315	1,082	1,133		80	48%
Total		29,589	16,484	280	8,080	537	1,865	2,020		80	
(302) Franchises & Consents		1,571									AE-ALL
- Demand	DMD-ALL	814	518	7	182	12	42	47		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	758	358	7	247	17	57	60		4	48%
Total		1,571	875	15	429	29	99	107		4	
(303) Misc. Intangible Plant		104,471,528									AE-ALL
- Demand	DMD-ALL	54,093,951	34,415,881	494,247	12,127,977	782,216	2,763,721	3,131,267		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	50,377,576	23,787,146	493,546	16,399,617	1,113,544	3,820,916	4,001,867		283,998	48%
Total		104,471,528	58,203,028	987,793	28,527,593	1,895,760	6,584,637	7,133,134		283,998	
Total Intangible Plant		104,502,688									
- Demand		54,110,086	34,426,146	494,394	12,131,594	782,450	2,764,545	3,132,201		-	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		50,392,602	23,794,241	493,694	16,404,508	1,113,876	3,822,055	4,003,061		284,083	
Total		104,502,688	58,220,387	988,088	28,536,102	1,896,326	6,586,601	7,135,262		284,083	
Distribution Plant											
(360) Land and Land Rights		16,328,813									AE-SEC
- Demand	DMD-SEC	8,889,267	6,397,530	91,875	2,254,456	145,405	-	-		-	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	7,439,547	4,205,671	87,261	2,899,523	196,879	-	-		50,212	46%
Total		16,328,813	10,603,201	179,136	5,153,980	342,285	-	-		50,212	
(361) Structures and Improvements		45,700,085									AE-SEC
- Demand	DMD-SEC	24,878,737	17,905,017	257,134	6,309,634	406,952	-	-		-	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	20,821,348	11,770,573	244,221	8,115,008	551,014	-	-		140,531	46%
Total		45,700,085	29,675,590	501,355	14,424,643	957,966	-	-		140,531	
(362) Station Equipment		294,950,319									AE-SEC
- Demand	DMD-SEC	160,568,441	115,559,752	1,659,554	40,722,653	2,626,483	-	-		-	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	134,381,878	75,967,789	1,576,214	52,374,615	3,556,268	-	-		906,991	46%
Total		294,950,319	191,527,541	3,235,768	93,097,268	6,182,751	-	-		906,991	
(364) Poles, Towers & Fixtures		395,829,391									AE-SEC
- Demand	DMD-SEC	215,486,148	155,083,562	2,227,155	54,650,637	3,524,794	-	-		-	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	180,343,243	101,950,335	2,115,312	70,287,810	4,772,585	-	-		1,217,201	46%
Total		395,829,391	257,033,897	4,342,467	124,938,447	8,297,379	-	-		1,217,201	
(365) Overhead Conductors & Devices		636,490,202									AE-SEC
- Demand	DMD-SEC	346,499,844	249,373,013	3,581,246	87,877,746	5,667,838	-	-		-	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	289,990,358	163,935,247	3,401,403	113,022,184	7,674,275	-	-		1,957,249	46%
Total		636,490,202	413,308,260	6,982,649	200,899,931	13,342,113	-	-		1,957,249	
(366) Underground Conduit		12,435,921									AE-SEC
- Demand	DMD-SEC	6,770,009	4,872,319	69,971	1,716,980	110,740	-	-		-	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	5,665,911	3,203,012	66,458	2,208,259	149,942	-	-		38,241	46%
Total		12,435,921	8,075,330	136,429	3,925,238	260,682	-	-		38,241	
(367) Underground Conductors & Device		347,686,952									AE-SEC
- Demand	DMD-SEC	189,277,815	136,221,646	1,956,279	48,003,796	3,096,094	-	-		-	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	158,409,137	89,550,705	1,858,039	61,739,110	4,192,123	-	-		1,069,160	46%
Total		347,686,952	225,772,351	3,814,318	109,742,906	7,288,217	-	-		1,069,160	
(368) Line Transformers		909,589,450									AE-SEC
- Demand	DMD-SEC	495,172,748	356,371,647	5,117,854	125,583,506	8,099,741	-	-		-	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	414,416,702	234,275,046	4,860,845	161,516,683	10,967,081	-	-		2,797,047	46%
Total		909,589,450	590,646,694	9,978,699	287,100,189	19,066,822	-	-		2,797,047	
(369) Services		483,989,081									SRVC
- Demand	DMD-SEC	241,994,541	174,161,428	2,501,133	61,373,577	3,958,403	-	-		-	50%
- Customer	CUST-SVCS	241,994,541	211,638,975	2,995,338	27,320,701	39,526	-	-		-	50%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		483,989,081	385,800,404	5,496,471	88,694,278	3,997,928	-	-		-	
(370) Meters		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(371) Installation on Customers' Premises		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(373) Street Lighting & Signal Systems		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
(374) Asset Retirement Costs		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(375) Charging Stations		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
Total Distribution Plant		3,143,000,214									
- Demand		1,689,537,549	1,215,945,914	17,462,201	428,492,984	27,636,450	-	-		-	
- Customer		241,994,541	211,638,975	2,995,338	27,320,701	39,526	-	-		-	
- Commodity		1,211,468,124	684,858,379	14,209,752	472,163,193	32,060,168	-	-		8,176,632	
Total		3,143,000,214	2,112,443,268	34,667,291	927,976,879	59,736,143	-	-		8,176,632	
General Plant											
(389) Land and Land Rights		539,031									AE-ALL
- Demand	DMD-ALL	279,103	177,572	2,550	62,575	4,036	14,260	16,156		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	259,928	122,732	2,546	84,615	5,745	19,714	20,648		1,465	48%
Total		539,031	300,304	5,097	147,191	9,781	33,974	36,804		1,465	
(390) Structures and Improvements		38,105,421									AE-ALL
- Demand	DMD-ALL	19,730,474	12,553,005	180,274	4,423,613	285,309	1,008,052	1,142,113		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	18,374,947	8,676,232	180,018	5,981,671	406,159	1,393,658	1,459,659		103,587	48%
Total		38,105,421	21,229,238	360,292	10,405,284	691,468	2,401,710	2,601,772		103,587	
(391) Office Furniture & Equipment		12,930,053									AE-ALL
- Demand	DMD-ALL	6,695,008	4,259,526	61,171	1,501,035	96,812	342,055	387,545		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	6,235,046	2,944,047	61,084	2,029,720	137,819	472,901	495,296		35,149	48%
Total		12,930,053	7,203,573	122,255	3,530,754	234,631	814,956	882,842		35,149	
(392) Transportation Equipment		6,278,504									AE-ALL
- Demand	DMD-ALL	3,250,925	2,068,317	29,703	728,864	47,009	166,093	188,182		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	3,027,579	1,429,554	29,661	985,580	66,921	229,628	240,503		17,068	48%
Total		6,278,504	3,497,871	59,364	1,714,444	113,931	395,722	428,685		17,068	
(393) Stores Equipment		403,584									AE-ALL
- Demand	DMD-ALL	208,970	132,952	1,909	46,852	3,022	10,677	12,096		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	194,614	91,892	1,907	63,353	4,302	14,761	15,460		1,097	48%
Total		403,584	224,844	3,816	110,205	7,324	25,437	27,556		1,097	
(394) Tools, Shop & Garage Equipment		8,699,117									AE-ALL
- Demand	DMD-ALL	4,504,285	2,865,735	41,155	1,009,870	65,133	230,129	260,734		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	4,194,831	1,980,704	41,097	1,365,560	92,722	318,159	333,227		23,648	48%
Total		8,699,117	4,846,439	82,251	2,375,431	157,856	548,288	593,961		23,648	
(395) Laboratory Equipment		153,834									AE-ALL
- Demand	DMD-ALL	79,653	50,677	728	17,858	1,152	4,070	4,611		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	74,181	35,027	727	24,148	1,640	5,626	5,893		418	48%
Total		153,834	85,704	1,455	42,007	2,792	9,696	10,504		418	
(396) Power Operated Equipment		737,856									AE-ALL
- Demand	DMD-ALL	382,052	243,071	3,491	85,657	5,525	19,519	22,115		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	355,804	168,003	3,486	115,826	7,865	26,986	28,264		2,006	48%
Total		737,856	411,073	6,977	201,483	13,389	46,506	50,380		2,006	
(397) Communication Equipment		23,471,643									AE-ALL
- Demand	DMD-ALL	12,153,301	7,732,224	111,042	2,724,795	175,741	620,926	703,503		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	11,318,342	5,344,264	110,885	3,684,506	250,180	858,446	899,100		63,806	48%
Total		23,471,643	13,076,488	221,928	6,409,301	425,921	1,479,372	1,602,603		63,806	
(398) Misc. Equipment		63,255									AE-ALL
- Demand	DMD-ALL	32,753	20,838	299	7,343	474	1,673	1,896		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	30,503	14,403	299	9,930	674	2,313	2,423		172	48%
Total		63,255	35,241	598	17,273	1,148	3,987	4,319		172	
(399) Other Tangible Property		525,965									AE-ALL
- Demand	DMD-ALL	272,338	173,268	2,488	61,059	3,938	13,914	15,764		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	253,627	119,757	2,485	82,564	5,606	19,237	20,148		1,430	48%
Total		525,965	293,025	4,973	143,623	9,544	33,151	35,912		1,430	
(SRVCO-PIS) Service Company PIS		50,299,237									AE-ALL
- Demand	DMD-ALL	26,044,268	16,569,994	237,962	5,839,179	376,609	1,330,631	1,507,591		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	24,254,969	11,452,645	237,625	7,895,818	536,131	1,839,632	1,926,753		136,735	48%
Total		50,299,237	28,022,639	475,586	13,734,998	912,740	3,170,263	3,434,344		136,735	
Total General Plant		142,207,500									
- Demand		73,633,130	46,847,180	672,772	16,508,701	1,064,759	3,762,000	4,262,307		-	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		68,574,370	32,379,259	671,820	22,323,293	1,515,765	5,201,062	5,447,374		386,581	
Total		142,207,500	79,226,438	1,344,592	38,831,994	2,580,524	8,963,062	9,709,681		386,581	
Total Utility Plant		3,389,710,401									
- Demand		1,817,280,765	1,297,219,240	18,629,368	457,133,280	29,483,659	6,526,545	7,394,508		-	
- Customer		241,994,541	211,638,975	2,995,338	27,320,701	39,526	-	-		-	
- Commodity		1,330,435,095	741,031,879	15,375,265	510,890,994	34,689,809	9,023,117	9,450,435		8,847,296	
Total		3,389,710,401	2,249,890,094	36,999,971	995,344,975	64,212,993	15,549,662	16,844,943		8,847,296	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
Additions to Utility Plant											
Construction Work in Progress		-									
- Demand		-	-	-	-	-	-	-		-	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		-	-	-	-	-	-	-		-	
Total		-	-	-	-	-	-	-		-	
Total Additional to Utility Plant		-									
- Demand		-	-	-	-	-	-	-		-	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		-	-	-	-	-	-	-		-	
Total		-	-	-	-	-	-	-		-	
Total Utility Plant		3,389,710,401									
- Demand		1,817,280,765	1,297,219,240	18,629,368	457,133,280	29,483,659	6,526,545	7,394,508		-	
- Customer		241,994,541	211,638,975	2,995,338	27,320,701	39,526	-	-		-	
- Commodity		1,330,435,095	741,031,879	15,375,265	510,890,994	34,689,809	9,023,117	9,450,435		8,847,296	
Total		**3,389,710,401**	**2,249,890,094**	**36,999,971**	**995,344,975**	**64,212,993**	**15,549,662**	**16,844,943**		**8,847,296**	
ACCUMULATED DEPRECIATION											
Accumulated Depreciation											
(108-303) Misc Intangible Plant		(65,064,960)									AE-ALL
- Demand	DMD-ALL	(33,689,761)	(21,434,241)	(307,817)	(7,553,315)	(487,165)	(1,721,248)	(1,950,156)		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(31,375,199)	(14,814,656)	(307,381)	(10,213,696)	(693,516)	(2,379,670)	(2,492,366)		(176,875)	48%
Total		(65,064,960)	(36,248,897)	(615,198)	(17,767,010)	(1,180,681)	(4,100,918)	(4,442,522)		(176,875)	
(108-360) Land & Land Rights		(9,226,037)									AE-SEC
- Demand	DMD-SEC	(5,022,576)	(3,614,706)	(51,911)	(1,273,803)	(82,156)	-	-		-	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	(4,203,461)	(2,376,270)	(49,304)	(1,638,276)	(111,240)	-	-		(28,371)	46%
Total		(9,226,037)	(5,990,976)	(101,215)	(2,912,080)	(193,396)	-	-		(28,371)	
(108-361) Struct & Impmnts		(8,588,758)									AE-SEC
- Demand	DMD-SEC	(4,675,647)	(3,365,024)	(48,325)	(1,185,817)	(76,481)	-	-		-	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	(3,913,111)	(2,212,132)	(45,898)	(1,525,114)	(103,556)	-	-		(26,411)	46%
Total		(8,588,758)	(5,577,155)	(94,223)	(2,710,931)	(180,038)	-	-		(26,411)	
(108-362) Station Equip		(102,333,669)									AE-SEC
- Demand	DMD-SEC	(55,709,578)	(40,093,713)	(575,786)	(14,128,815)	(911,264)	-	-		-	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	(46,624,091)	(26,357,193)	(546,871)	(18,171,489)	(1,233,855)	-	-		(314,683)	46%
Total		(102,333,669)	(66,450,906)	(1,122,657)	(32,300,304)	(2,145,119)	-	-		(314,683)	
(108-364) Poles, Towers & Fixt		(151,290,456)									AE-SEC
- Demand	DMD-SEC	(82,361,235)	(59,274,686)	(851,244)	(20,888,089)	(1,347,216)	-	-		-	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	(68,929,220)	(38,966,567)	(808,496)	(26,864,793)	(1,824,136)	-	-		(465,228)	46%
Total		(151,290,456)	(98,241,253)	(1,659,740)	(47,752,883)	(3,171,352)	-	-		(465,228)	
(108-365) OH Cond & Dev		(97,687,661)									AE-SEC
- Demand	DMD-SEC	(53,180,330)	(38,273,435)	(549,645)	(13,487,358)	(869,892)	-	-		-	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	(44,507,330)	(25,160,561)	(522,043)	(17,346,493)	(1,177,837)	-	-		(300,396)	46%
Total		(97,687,661)	(63,433,996)	(1,071,688)	(30,833,851)	(2,047,730)	-	-		(300,396)	
(108-366) UG Conduit		(6,202,112)									AE-SEC
- Demand	DMD-SEC	(3,376,377)	(2,429,950)	(34,897)	(856,302)	(55,229)	-	-		-	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	(2,825,735)	(1,597,424)	(33,144)	(1,101,315)	(74,780)	-	-		(19,072)	46%
Total		(6,202,112)	(4,027,374)	(68,041)	(1,957,617)	(130,009)	-	-		(19,072)	
(108-367) UG Cond & Dev		(117,495,009)									AE-SEC
- Demand	DMD-SEC	(63,963,282)	(46,033,834)	(661,092)	(16,222,083)	(1,046,273)	-	-		-	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	(53,531,727)	(30,262,168)	(627,893)	(20,863,703)	(1,416,658)	-	-		(361,305)	46%
Total		(117,495,009)	(76,296,002)	(1,288,985)	(37,085,786)	(2,462,931)	-	-		(361,305)	
(108-368) Line Transformers		(315,307,756)									AE-SEC
- Demand	DMD-SEC	(171,650,856)	(123,535,673)	(1,774,096)	(43,533,325)	(2,807,763)	-	-		-	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	(143,656,900)	(81,211,077)	(1,685,004)	(55,989,505)	(3,801,721)	-	-		(969,592)	46%
Total		(315,307,756)	(204,746,750)	(3,459,100)	(99,522,830)	(6,609,484)	-	-		(969,592)	
(108-369) Services		(191,180,068)									SRVC
- Demand	DMD-SEC	(95,590,034)	(68,795,341)	(987,970)	(24,243,119)	(1,563,605)	-	-		-	50%
- Customer	CUST-SVCS	(95,590,034)	(83,599,311)	(1,183,186)	(10,791,924)	(15,613)	-	-		-	50%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		(191,180,068)	(152,394,652)	(2,171,156)	(35,035,043)	(1,579,218)	-	-		-	
(108-370) Meters		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(108-371) Install on Cust Premise		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(108-373) St Lt & Signal Sys		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
(108-374) Asset Ret Costs		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(108-389) Land & Land Rights		(4,140)									AE-ALL
- Demand	DMD-ALL	(2,143)	(1,364)	(20)	(481)	(31)	(110)	(124)		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(1,996)	(943)	(20)	(650)	(44)	(151)	(159)		(11)	48%
Total		(4,140)	(2,306)	(39)	(1,130)	(75)	(261)	(283)		(11)	
(108-390) Struct & Impmnts -		(33,630,647)									AE-ALL
- Demand	DMD-ALL	(17,413,496)	(11,078,888)	(159,104)	(3,904,142)	(251,805)	(889,675)	(1,007,993)		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(16,217,150)	(7,657,370)	(158,879)	(5,279,235)	(358,463)	(1,229,999)	(1,288,249)		(91,423)	48%
Total		(33,630,647)	(18,736,258)	(317,983)	(9,183,377)	(610,268)	(2,119,674)	(2,296,242)		(91,423)	
(108-391) Office Furn & Equip		(3,754,727)									AE-ALL
- Demand	DMD-ALL	(1,944,147)	(1,236,913)	(17,763)	(435,882)	(28,113)	(99,329)	(112,538)		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(1,810,580)	(854,915)	(17,738)	(589,405)	(40,021)	(137,324)	(143,828)		(10,207)	48%
Total		(3,754,727)	(2,091,828)	(35,501)	(1,025,287)	(68,134)	(236,653)	(256,366)		(10,207)	
(108-392) Transportation Equip		(3,097,257)									AE-ALL
- Demand	DMD-ALL	(1,603,718)	(1,020,324)	(14,653)	(359,557)	(23,190)	(81,936)	(92,832)		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(1,493,539)	(705,215)	(14,632)	(486,198)	(33,013)	(113,278)	(118,643)		(8,420)	48%
Total		(3,097,257)	(1,725,539)	(29,285)	(845,755)	(56,203)	(195,214)	(211,475)		(8,420)	
(108-393) Stores Equip		(573,955)									AE-ALL
- Demand	DMD-ALL	(297,186)	(189,077)	(2,715)	(66,630)	(4,297)	(15,184)	(17,203)		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(276,769)	(130,684)	(2,711)	(90,098)	(6,118)	(20,992)	(21,986)		(1,560)	48%
Total		(573,955)	(319,761)	(5,427)	(156,727)	(10,415)	(36,175)	(39,189)		(1,560)	
(108-394) Tools, Shop & Garage Equip		(6,416,893)									AE-ALL
- Demand	DMD-ALL	(3,322,581)	(2,113,906)	(30,358)	(744,930)	(48,046)	(169,754)	(192,330)		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(3,094,312)	(1,461,064)	(30,315)	(1,007,304)	(68,397)	(234,690)	(245,804)		(17,444)	48%
Total		(6,416,893)	(3,574,970)	(60,673)	(1,752,234)	(116,442)	(404,444)	(438,134)		(17,444)	
(108-395) Laboratory Equip		(250,955)									AE-ALL
- Demand	DMD-ALL	(129,941)	(82,672)	(1,187)	(29,133)	(1,879)	(6,639)	(7,522)		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(121,014)	(57,140)	(1,186)	(39,394)	(2,675)	(9,178)	(9,613)		(682)	48%
Total		(250,955)	(139,812)	(2,373)	(68,527)	(4,554)	(15,817)	(17,135)		(682)	
(108-396) Power Operated Equip		(720,253)									AE-ALL
- Demand	DMD-ALL	(372,937)	(237,272)	(3,407)	(83,613)	(5,393)	(19,054)	(21,588)		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(347,316)	(163,995)	(3,403)	(113,063)	(7,677)	(26,342)	(27,590)		(1,958)	48%
Total		(720,253)	(401,266)	(6,810)	(196,676)	(13,070)	(45,396)	(49,178)		(1,958)	
(108-397) Communication Equip		(7,849,127)									AE-ALL
- Demand	DMD-ALL	(4,064,172)	(2,585,725)	(37,134)	(911,196)	(58,769)	(207,643)	(235,258)		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(3,784,954)	(1,787,169)	(37,081)	(1,232,132)	(83,662)	(287,072)	(300,667)		(21,337)	48%
Total		(7,849,127)	(4,372,894)	(74,215)	(2,143,327)	(142,432)	(494,715)	(535,925)		(21,337)	
(108-398) MISC Equip		(128,481)									AE-ALL
- Demand	DMD-ALL	(66,526)	(42,325)	(608)	(14,915)	(962)	(3,399)	(3,851)		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(61,955)	(29,254)	(607)	(20,169)	(1,369)	(4,699)	(4,922)		(349)	48%
Total		(128,481)	(71,579)	(1,215)	(35,084)	(2,331)	(8,098)	(8,772)		(349)	
(108-399) Other Tangible Property		-									AE-ALL
- Demand	DMD-ALL	-	-	-	-	-	-	-		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	-	-	-	-	-	-	-		-	48%
Total		-	-	-	-	-	-	-		-	
Service Company PIS		(49,961,808)									AE-ALL
- Demand	DMD-ALL	(25,869,552)	(16,458,835)	(236,365)	(5,800,007)	(374,082)	(1,321,705)	(1,497,478)		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(24,092,256)	(11,375,816)	(236,031)	(7,842,850)	(532,534)	(1,827,291)	(1,913,828)		(135,818)	48%
Total		(49,961,808)	(27,834,651)	(472,396)	(13,642,857)	(906,617)	(3,148,995)	(3,411,305)		(135,818)	
Total Accumulated Depreciation		(1,170,764,729)									
- Demand		(624,306,077)	(441,897,903)	(6,346,097)	(155,722,511)	(10,043,612)	(4,535,674)	(5,138,872)		-	
- Customer		(95,590,034)	(83,599,311)	(1,183,186)	(10,791,924)	(15,613)	-	-		-	
- Commodity		(450,868,618)	(247,181,613)	(5,128,636)	(170,414,882)	(11,571,274)	(6,270,687)	(6,567,655)		(2,951,140)	
Total Accumulated Depreciation		**(1,170,764,729)**	**(772,678,827)**	**(12,657,918)**	**(336,929,317)**	**(21,630,499)**	**(10,806,361)**	**(11,706,526)**		**(2,951,140)**	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG	Classification Factor
OTHER RATE BASE ITEMS											
Other Rate Base Items											
Materials and Supplies		14,639,069									DISTPLT-SEC
- Demand	DISTPLT-SEC-D	7,869,315	5,663,479	81,333	1,995,780	128,722	-	-		-	54%
- Customer	DISTPLT-SEC-C	1,127,132	985,745	13,951	127,251	184	-	-		-	8%
- Commodity	DISTPLT-SEC-E	5,642,623	3,189,847	66,184	2,199,182	149,326	-	-		38,084	39%
Total		14,639,069	9,839,071	161,469	4,322,213	278,231	-	-		38,084	
Cash Working Capital		37,767,671									CWC-SEC
- Demand	CWC-SEC-D	20,554,904	14,793,191	212,445	5,213,043	336,225	-	-		-	54%
- Customer	CWC-SEC-C	486,095	425,120	6,017	54,879	79	-	-		-	1%
- Commodity	CWC-SEC-E	16,726,671	9,455,801	196,193	6,519,130	442,653	-	-		112,894	44%
Total		37,767,671	24,674,111	414,655	11,787,053	778,957	-	-		112,894	
ADIT		(669,175,588)									DISTPLT-SEC
- Demand	DISTPLT-SEC-D	(359,719,124)	(258,886,817)	(3,717,874)	(91,230,361)	(5,884,071)	-	-		-	54%
- Customer	DISTPLT-SEC-C	(51,523,012)	(45,060,015)	(637,737)	(5,816,845)	(8,415)	-	-		-	8%
- Commodity	DISTPLT-SEC-E	(257,933,452)	(145,813,070)	(3,025,396)	(100,528,177)	(6,825,924)	-	-		(1,740,885)	39%
Total		(669,175,588)	(449,759,902)	(7,381,007)	(197,575,384)	(12,718,411)	-	-		(1,740,885)	
Net /Loss on Reacq Debt		766,808									DISTPLT-SEC
- Demand	DISTPLT-SEC-D	412,202	296,658	4,260	104,541	6,743	-	-		-	54%
- Customer	DISTPLT-SEC-C	59,040	51,634	731	6,666	10	-	-		-	8%
- Commodity	DISTPLT-SEC-E	295,566	167,087	3,467	115,195	7,822	-	-		1,995	39%
Total		766,808	515,380	8,458	226,402	14,574	-	-		1,995	
DTA for AMT		5,321,747									DISTPLT-SEC
- Demand	DISTPLT-SEC-D	2,860,735	2,058,847	29,567	725,527	46,794	-	-		-	54%
- Customer	DISTPLT-SEC-C	409,747	358,348	5,072	46,260	67	-	-		-	8%
- Commodity	DISTPLT-SEC-E	2,051,265	1,159,606	24,060	799,470	54,284	-	-		13,845	39%
Total		5,321,747	3,576,802	58,699	1,571,256	101,146	-	-		13,845	
Net Operating Reserves		(5,229,228)									PAY-SEC
- Demand	PAY-SEC-D	(2,823,507)	(2,000,338)	(28,727)	(704,909)	(45,464)	(44,069)	-		-	54%
- Customer	PAY-SEC-C	(49,661)	(41,714)	(590)	(5,385)	(8)	-	(1,964)		-	1%
- Commodity	PAY-SEC-E	(2,356,060)	(1,298,273)	(26,937)	(895,071)	(60,776)	(59,503)	-		(15,500)	45%
Total		(5,229,228)	(3,340,324)	(56,254)	(1,605,364)	(106,248)	(103,573)	(1,964)		(15,500)	
NOL		20,182,546									DISTPLT-SEC
- Demand	DISTPLT-SEC-D	10,849,242	7,808,108	112,132	2,751,536	177,465	-	-		-	54%
- Customer	DISTPLT-SEC-C	1,553,950	1,359,024	19,234	175,438	254	-	-		-	8%
- Commodity	DISTPLT-SEC-E	7,779,354	4,397,768	91,247	3,031,961	205,872	-	-		52,506	39%
Total		20,182,546	13,564,900	222,613	5,958,936	383,591	-	-		52,506	
CTA		(539,194)									TOTPLT-SEC
- Demand	TOTPLT-SEC-D	(289,071)	(206,346)	(2,963)	(72,715)	(4,690)	(1,038)	(1,176)		-	53.611682%
- Customer	TOTPLT-SEC-C	(38,494)	(33,665)	(476)	(4,346)	(6)	-	-		-	7.139092%
- Commodity	TOTPLT-SEC-E	(211,630)	(117,874)	(2,446)	(81,266)	(5,518)	(1,435)	(1,503)		(1,407)	39.249226%
Total		(539,194)	(357,885)	(5,886)	(158,327)	(10,214)	(2,473)	(2,679)		(1,407)	
Regulatory Asset A&G Capitalization		30,708,163									AE-PRI-GTA&G
- Demand	DMD-PRI	16,259,637	11,062,575	158,870	3,898,393	251,434	888,365	-		-	53%
- Customer	CUST-GTA&G	39,596	-	-	-	-	-	39,596		-	0%
- Commodity	NRG-PRI	14,408,930	7,467,463	154,938	5,148,307	349,573	1,199,494	-		89,155	47%
Total		30,708,163	18,530,037	313,808	9,046,700	601,007	2,087,859	39,596		89,155	
Customer Deposits		-									CUS
- Demand		-	-	-	-	-	-	-		-	0%
- Customer		-	-	-	-	-	-	-		-	100%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		-	-	-	-	-	-	-		-	
Customer Advances		(27,862,053)									DISTPLT-SEC
- Demand	DISTPLT-SEC-D	(14,977,404)	(10,779,111)	(154,799)	(3,798,503)	(244,991)	-	-		-	54%
- Customer	DISTPLT-SEC-C	(2,145,232)	(1,876,136)	(26,553)	(242,192)	(350)	-	-		-	8%
- Commodity	DISTPLT-SEC-E	(10,739,417)	(6,071,129)	(125,967)	(4,185,630)	(284,207)	-	-		(72,484)	39%
Total		(27,862,053)	(18,726,377)	(307,318)	(8,226,325)	(529,549)	-	-		(72,484)	
Customer Refunds		(155,489)									DISTPLT-SEC
- Demand	DISTPLT-SEC-D	(83,584)	(60,155)	(864)	(21,198)	(1,367)	-	-		-	54%
- Customer	DISTPLT-SEC-C	(11,972)	(10,470)	(148)	(1,352)	(2)	-	-		-	8%
- Commodity	DISTPLT-SEC-E	(59,933)	(33,881)	(703)	(23,359)	(1,586)	-	-		(405)	39%
Total		(155,489)	(104,506)	(1,715)	(45,908)	(2,955)	-	-		(405)	
Total Other Rate Base Items		(593,575,548)									
- Demand		(319,086,655)	(230,249,909)	(3,306,619)	(81,138,865)	(5,233,202)	843,258	(1,176)		-	
- Customer		(50,092,812)	(43,842,128)	(620,500)	(5,659,627)	(8,188)	-	37,631		-	
- Commodity		(224,396,081)	(127,496,655)	(2,645,358)	(87,900,257)	(5,968,481)	1,138,556	(1,503)		(1,522,203)	
Total		(593,575,548)	(401,588,692)	(6,572,478)	(174,698,749)	(11,209,870)	1,981,813	34,952		(1,522,203)	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
Rate Base Adjustment											
Adjustment											
AMI		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
Delayed Recognition Pension & OPEB		(12,994,369)									PAY-SEC
- Demand	PAY-SEC-D	(7,016,272)	(4,970,738)	(71,385)	(1,751,662)	(112,977)	(109,510)	-		-	54%
- Customer	PAY-SEC-C	(123,406)	(103,658)	(1,467)	(13,381)	(19)	-	(4,881)		-	1%
- Commodity	PAY-SEC-E	(5,854,690)	(3,226,142)	(66,937)	(2,224,205)	(151,025)	(147,863)	-		(38,517)	45%
Total		(12,994,369)	(8,300,538)	(139,789)	(3,989,249)	(264,021)	(257,373)	(4,881)		(38,517)	
Total Rate Base Adjustment		(12,994,369)									
- Demand		(7,016,272)	(4,970,738)	(71,385)	(1,751,662)	(112,977)	(109,510)	-		-	
- Customer		(123,406)	(103,658)	(1,467)	(13,381)	(19)	-	(4,881)		-	
- Commodity		(5,854,690)	(3,226,142)	(66,937)	(2,224,205)	(151,025)	(147,863)	-		(38,517)	
Total		(12,994,369)	(8,300,538)	(139,789)	(3,989,249)	(264,021)	(257,373)	(4,881)		(38,517)	
Total Rate Base		**1,612,375,756**									
- Demand		**866,871,761**	**620,100,689**	**8,905,267**	**218,520,242**	**14,093,868**	**2,724,619**	**2,254,460**		**-**	
- Customer		**96,188,288**	**84,093,879**	**1,190,185**	**10,855,769**	**15,705**	**-**	**32,750**		**-**	
- Commodity		**649,315,706**	**363,127,469**	**7,534,333**	**250,351,650**	**16,999,029**	**3,743,123**	**2,881,277**		**4,335,436**	
Total		**1,612,375,756**	**1,067,322,037**	**17,629,786**	**479,727,660**	**31,108,603**	**6,467,742**	**5,168,487**		**4,335,436**	
OPERATIONS & MAINTENANCE EXPENSES											
Distribution Expenses											
Operations Expenses											
(580) Operation Supervision & Engineering		231,406									AE-SEC
- Demand	DMD-SEC	125,975	90,663	1,302	31,949	2,061	-	-		-	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	105,430	59,601	1,237	41,091	2,790	-	-		712	46%
Total		231,406	150,265	2,539	73,040	4,851	-	-		712	
(581) Load Dispatching		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(582) Station Expenses		304,563									AE-SEC
- Demand	DMD-SEC	165,802	119,326	1,714	42,050	2,712	-	-		-	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	138,761	78,444	1,628	54,082	3,672	-	-		937	46%
Total		304,563	197,770	3,341	96,131	6,384	-	-		937	
(583) Overhead line expenses		520,027									AE-SEC
- Demand	DMD-SEC	283,098	203,743	2,926	71,798	4,631	-	-		-	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	236,929	133,939	2,779	92,342	6,270	-	-		1,599	46%
Total		520,027	337,682	5,705	164,140	10,901	-	-		1,599	
(584) Underground line expenses		1,987,209									AE-SEC
- Demand	DMD-SEC	1,081,819	778,576	11,181	274,366	17,696	-	-		-	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	905,389	511,828	10,620	352,871	23,960	-	-		6,111	46%
Total		1,987,209	1,290,404	21,801	627,237	41,656	-	-		6,111	
(585) Street lighting and signal system expenses		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(586) Meter expenses		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(587) Customer installations expenses		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(588) Miscellaneous distribution expenses		10,402,194									DISTPLT-SEC
- Demand	DISTPLT-SEC-D	5,591,758	4,024,341	57,794	1,418,157	91,467	-	-		-	54%
- Customer	DISTPLT-SEC-C	800,914	700,448	9,913	90,422	131	-	-		-	8%
- Commodity	DISTPLT-SEC-E	4,009,522	2,266,634	47,029	1,562,689	106,108	-	-		27,062	39%
Total		10,402,194	6,991,424	114,736	3,071,268	197,705	-	-		27,062	
(589) Rents		2,236,678									AE-SEC
- Demand	DMD-SEC	1,217,628	876,317	12,585	308,809	19,917	-	-		-	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	1,019,050	576,082	11,953	397,169	26,968	-	-		6,878	46%
Total		2,236,678	1,452,399	24,538	705,979	46,885	-	-		6,878	
Total Dist. Operations Expenses		15,682,077									
- Demand		8,466,081	6,092,967	87,501	2,147,130	138,483	-	-		-	
- Customer		800,914	700,448	9,913	90,422	131	-	-		-	
- Commodity		6,415,081	3,626,527	75,245	2,500,243	169,768	-	-		43,298	
Total		15,682,077	10,419,943	172,659	4,737,795	308,382	-	-		43,298	
Maintenance Expense											
(590) Maintenance Supervision and Engineering		1,786,832									AE-SEC
- Demand	DMD-SEC	972,736	700,070	10,054	246,701	15,911	-	-		-	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	814,096	460,219	9,549	317,290	21,544	-	-		5,495	46%
Total		1,786,832	1,160,289	19,603	563,991	37,456	-	-		5,495	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
(591) Maintenance of Structures		-									AE-SEC
- Demand		-	-	-	-	-	-	-		-	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity		-	-	-	-	-	-	-		-	46%
Total		-	-	-	-	-	-	-		-	
(592) Maintenance of Station Equipment		5,986,956									AE-SEC
- Demand	DMD-SEC	3,259,248	2,345,653	33,686	826,596	53,313	-	-		-	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	2,727,708	1,542,008	31,994	1,063,110	72,186	-	-		18,410	46%
Total		5,986,956	3,887,661	65,680	1,889,706	125,499	-	-		18,410	
(593) Maintenance of Overhead Lines		42,114,302									AE-SEC
- Demand	DMD-SEC	22,926,667	16,500,129	236,958	5,814,559	375,021	-	-		-	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	19,187,635	10,847,015	225,059	7,478,278	507,780	-	-		129,504	46%
Total		42,114,302	27,347,143	462,017	13,292,837	882,800	-	-		129,504	
(594) Maintenance of underground lines		2,286,373									AE-SEC
- Demand	DMD-SEC	1,244,682	895,787	12,864	315,671	20,360	-	-		-	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	1,041,691	588,881	12,218	405,994	27,567	-	-		7,031	46%
Total		2,286,373	1,484,669	25,083	721,664	47,927	-	-		7,031	
(595) Maintenance of line transformers		151,393									DEM
- Demand	DMD-SEC	151,393	108,956	1,565	38,396	2,476	-	-		-	100%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		151,393	108,956	1,565	38,396	2,476	-	-		-	
(596) Maintenance of street lighting and signal systems		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(597) Maintenance of meters		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(598) Maintenance of miscellaneous distribution plant		1,160,143									DISTPLT-SEC
- Demand	DISTPLT-SEC-D	623,642	448,830	6,446	158,165	10,201	-	-		-	54%
- Customer	DISTPLT-SEC-C	89,325	78,120	1,106	10,085	15	-	-		-	8%
- Commodity	DISTPLT-SEC-E	447,177	252,795	5,245	174,285	11,834	-	-		3,018	39%
Total		1,160,143	779,745	12,796	342,535	22,050	-	-		3,018	
Total Dist. Maintenance Expenses		53,486,000									
- Demand		29,178,368	20,999,425	301,573	7,400,088	477,282	-	-		-	
- Customer		89,325	78,120	1,106	10,085	15	-	-		-	
- Commodity		24,218,307	13,690,918	284,065	9,438,955	640,911	-	-		163,458	
Total		53,486,000	34,768,463	586,744	16,849,127	1,118,208	-	-		163,458	
Total Distribution Expenses		69,168,077									
- Demand		37,644,450	27,092,393	389,074	9,547,218	615,766	-	-		-	
- Customer		890,239	778,569	11,019	100,506	145	-	-		-	
- Commodity		30,633,388	17,317,445	359,310	11,939,198	810,679	-	-		206,756	
Total		69,168,077	45,188,406	759,403	21,586,922	1,426,590	-	-		206,756	
Customer Account Expense											
(901) Supervision		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(902) Meter reading expenses		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(903) Customer records and collection expenses		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(904) Uncollectible accounts		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(905) Miscellaneous customer accounts expenses		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
Total Customer Account Expenses		-									
- Demand		-	-	-	-	-	-	-		-	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		-	-	-	-	-	-	-		-	
Total		-	-	-	-	-	-	-		-	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
Customer Service Expenses											
(907) Customer Service Supervision		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(908) Customer Assistance		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(909) Informational and instructional advertising		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(910) Miscellaneous customer service and informational		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
Total Customer Service Expenses		-									
- Demand		-	-	-	-	-	-	-		-	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		-	-	-	-	-	-	-		-	
Total		-	-	-	-	-	-	-		-	
Sales Expenses											
(911) Sales Exp		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
Total Sales Expenses		-									
- Demand		-	-	-	-	-	-	-		-	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		-	-	-	-	-	-	-		-	
Total		-	-	-	-	-	-	-		-	
Administrative & General Expense											
Labor Related											
(920) Administrative and general salaries		4,744,521									AE-PRI-GTA&G
- Demand	DMD-PRI	2,512,172	1,709,207	24,546	602,316	38,847	137,256	-		-	53%
- Customer	CUST-GTA&G	6,118	-	-	-	-	-	6,118		-	0%
- Commodity	NRG-PRI	2,226,231	1,153,750	23,939	795,432	54,010	185,326	-		13,775	47%
Total		4,744,521	2,862,957	48,484	1,397,748	92,858	322,582	6,118		13,775	
(921) Office supplies and expenses		424,403									AE-PRI-GTA&G
- Demand	DMD-PRI	224,717	152,891	2,196	53,878	3,475	12,278	-		-	53%
- Customer	CUST-GTA&G	547	-	-	-	-	-	547		-	0%
- Commodity	NRG-PRI	199,139	103,204	2,141	71,152	4,831	16,578	-		1,232	47%
Total		424,403	256,095	4,337	125,030	8,306	28,855	547		1,232	
(922) Administrative expenses transferred—Credit		(422,542)									AE-PRI-GTA&G
- Demand	DMD-PRI	(223,732)	(152,220)	(2,186)	(53,642)	(3,460)	(12,224)	-		-	53%
- Customer	CUST-GTA&G	(545)	-	-	-	-	-	(545)		-	0%
- Commodity	NRG-PRI	(198,266)	(102,752)	(2,132)	(70,840)	(4,810)	(16,505)	-		(1,227)	47%
Total		(422,542)	(254,972)	(4,318)	(124,482)	(8,270)	(28,729)	(545)		(1,227)	
(923) Outside services employed		15,453,805									AE-PRI-GTA&G
- Demand	DMD-PRI	8,182,621	5,567,213	79,951	1,961,857	126,534	447,068	-		-	53%
- Customer	CUST-GTA&G	19,926	-	-	-	-	-	19,926		-	0%
- Commodity	NRG-PRI	7,251,258	3,757,982	77,972	2,590,872	175,922	603,642	-		44,867	47%
Total		15,453,805	9,325,194	157,923	4,552,729	302,455	1,050,710	19,926		44,867	
(926) Employee pensions and benefits		(954,134)									AE-PRI-GTA&G
- Demand	DMD-PRI	(505,204)	(343,726)	(4,936)	(121,127)	(7,812)	(27,602)	-		-	53%
- Customer	CUST-GTA&G	(1,230)	-	-	-	-	-	(1,230)		-	0%
- Commodity	NRG-PRI	(447,700)	(232,022)	(4,814)	(159,963)	(10,862)	(37,270)	-		(2,770)	47%
Total		(954,134)	(575,747)	(9,750)	(281,090)	(18,674)	(64,872)	(1,230)		(2,770)	
(426) Pension / OPEB Non-Service Cost		-									AE-PRI-GTA&G
- Demand		-	-	-	-	-	-	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity		-	-	-	-	-	-	-		-	47%
Total		-	-	-	-	-	-	-		-	
(924) Property insurance		157,595									AE-PRI-GTA&G
- Demand	DMD-PRI	83,445	56,774	815	20,007	1,290	4,559	-		-	53%
- Customer	CUST-GTA&G	203	-	-	-	-	-	203		-	0%
- Commodity	NRG-PRI	73,947	38,323	795	26,421	1,794	6,156	-		458	47%
Total		157,595	95,097	1,610	46,428	3,084	10,715	203		458	
(925) Injuries and damages		2,878,295									AE-PRI-GTA&G
- Demand	DMD-PRI	1,524,026	1,036,902	14,891	365,399	23,567	83,267	-		-	53%
- Customer	CUST-GTA&G	3,711	-	-	-	-	-	3,711		-	0%
- Commodity	NRG-PRI	1,350,558	699,930	14,522	482,554	32,766	112,429	-		8,357	47%
Total		2,878,295	1,736,832	29,413	847,953	56,333	195,696	3,711		8,357	
(935) Maintenance of general plant		2,574,516									AE-PRI-GTA&G
- Demand	DMD-PRI	1,363,178	927,466	13,319	326,834	21,080	74,479	-		-	53%
- Customer	CUST-GTA&G	3,320	-	-	-	-	-	3,320		-	0%
- Commodity	NRG-PRI	1,208,018	626,058	12,990	431,625	29,308	100,563	-		7,475	47%
Total		2,574,516	1,553,524	26,309	758,459	50,387	175,042	3,320		7,475	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
(929) Duplicate charges—Credit		-									AE-PRI-GTA&G
- Demand		-	-	-	-	-	-	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity		-	-	-	-	-	-	-		-	47%
Total		-	-	-	-	-	-	-		-	
(928) Regulatory commission expenses		1,696,822									AE-PRI-GTA&G
- Demand	DMD-PRI	898,449	611,278	8,779	215,411	13,893	49,088	-		-	53%
- Customer	CUST-GTA&G	2,188	-	-	-	-	-	2,188		-	0%
- Commodity	NRG-PRI	796,186	412,625	8,561	284,477	19,316	66,280	-		4,926	47%
Total		1,696,822	1,023,903	17,340	499,888	33,209	115,368	2,188		4,926	
(930.1) Gen Advertising Exp		272,186									AE-PRI-GTA&G
- Demand	DMD-PRI	144,120	98,055	1,408	34,554	2,229	7,874	-		-	53%
- Customer	CUST-GTA&G	351	-	-	-	-	-	351		-	0%
- Commodity	NRG-PRI	127,716	66,189	1,373	45,633	3,098	10,632	-		790	47%
Total		272,186	164,244	2,781	80,187	5,327	18,506	351		790	
(930.2) Misc Gen Exp		852,224									AE-PRI-GTA&G
- Demand	DMD-PRI	451,243	307,013	4,409	108,190	6,978	24,654	-		-	53%
- Customer	CUST-GTA&G	1,099	-	-	-	-	-	1,099		-	0%
- Commodity	NRG-PRI	399,882	207,240	4,300	142,878	9,701	33,289	-		2,474	47%
Total		852,224	514,252	8,709	251,067	16,679	57,943	1,099		2,474	
(931) Rents		754,571									AE-PRI-GTA&G
- Demand	DMD-PRI	399,537	271,833	3,904	95,793	6,178	21,829	-		-	53%
- Customer	CUST-GTA&G	973	-	-	-	-	-	973		-	0%
- Commodity	NRG-PRI	354,061	183,493	3,807	126,506	8,590	29,474	-		2,191	47%
Total		754,571	455,326	7,711	222,298	14,768	51,304	973		2,191	
(932) Institutional Ad - Newspaper		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(933) Transportation expenses		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total A&G Expense		28,432,263									
- Demand		15,054,573	10,242,685	147,095	3,609,469	232,799	822,525	-		-	
- Customer		36,661	-	-	-	-	-	36,661		-	
- Commodity		13,341,029	6,914,020	143,455	4,766,746	323,665	1,110,595	-		82,548	
Total		28,432,263	17,156,705	290,550	8,376,215	556,464	1,933,120	36,661		82,548	
O&M Adjustment											
Adjustment											
Int on Cust Deposits		-									CUS
- Demand		-	-	-	-	-	-	-		-	0%
- Customer	CUST-DEP	-	-	-	-	-	-	-		-	100%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		-	-	-	-	-	-	-		-	
Annualize Payroll Increase		1,882,187									PAY-SEC
- Demand	PAY-SEC-D	1,016,281	719,993	10,340	253,722	16,364	15,862	-		-	54%
- Customer	PAY-SEC-C	17,875	15,014	212	1,938	3	-	707		-	1%
- Commodity	PAY-SEC-E	848,031	467,295	9,696	322,168	21,875	21,417	-		5,579	45%
Total		1,882,187	1,202,303	20,248	577,828	38,242	37,280	707		5,579	
Svngs Pln Match on Payroll Inc		56,466									PAY-SEC
- Demand	PAY-SEC-D	30,488	21,600	310	7,612	491	476	-		-	54%
- Customer	PAY-SEC-C	536	450	6	58	0	-	21		-	1%
- Commodity	PAY-SEC-E	25,441	14,019	291	9,665	656	643	-		167	45%
Total		56,466	36,069	607	17,335	1,147	1,118	21		167	
Reclass Amortization of Net Loss on Reacquired Debt		355,159									DISTPLT-SEC
- Demand	DISTPLT-SEC-D	190,918	137,402	1,973	48,420	3,123	-	-		-	54%
- Customer	DISTPLT-SEC-C	27,345	23,915	338	3,087	4	-	-		-	8%
- Commodity	DISTPLT-SEC-E	136,896	77,389	1,606	53,354	3,623	-	-		924	39%
Total		355,159	238,706	3,917	104,861	6,750	-	-		924	
BPU & RPA Assessments		454,999									DIST-REV
- Demand	DIST-REV-DMD	120,160	-	-	77,644	6,125	15,108	11,227		9,841	26%
- Customer	DIST-REV-CUST	36,637	26,131	797	8,973	76	294	364		-	8%
- Commodity	DIST-REV-NRG	298,201	221,487	4,097	60,494	1,509	3,884	2,940		3,791	66%
Total		454,999	247,618	4,894	147,111	7,709	19,287	14,530		13,631	
Rate Case Exp		-									AE-ALL
- Demand	DMD-ALL	-	-	-	-	-	-	-		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	-	-	-	-	-	-	-		-	48%
Total		-	-	-	-	-	-	-		-	
Pension Smoothing		5,146,795									PAY-SEC
- Demand	PAY-SEC-D	2,778,997	1,968,805	28,274	693,796	44,748	43,375	-		-	54%
- Customer	PAY-SEC-C	48,879	41,057	581	5,300	8	-	1,933		-	1%
- Commodity	PAY-SEC-E	2,318,919	1,277,807	26,513	880,961	59,818	58,565	-		15,256	45%
Total		5,146,795	3,287,668	55,368	1,580,057	104,573	101,940	1,933		15,256	
OPEB Smoothing		1,766,078									PAY-SEC
- Demand	PAY-SEC-D	953,589	675,578	9,702	238,070	15,355	14,884	-		-	54%
- Customer	PAY-SEC-C	16,772	14,088	199	1,819	3	-	663		-	1%
- Commodity	PAY-SEC-E	795,717	438,468	9,098	302,294	20,526	20,096	-		5,235	45%
Total		1,766,078	1,128,134	18,999	542,183	35,883	34,980	663		5,235	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
Normalize Vegetation Management Expense		4,138,329									OHPLT-SEC
- Demand	OHPLT-SEC-D	2,252,871	1,621,372	23,285	571,363	36,851	-	-		-	54%
- Customer	OHPLT-SEC-C	-	-	-	-	-	-	-		-	0%
- Commodity	OHPLT-SEC-E	1,885,458	1,065,873	22,115	734,847	49,897	-	-		12,726	46%
Total		4,138,329	2,687,246	45,400	1,306,210	86,748	-	-		12,726	
ServCo Depr @ JCP&L Rates		989,041									AE-ALL
- Demand	DMD-ALL	512,112	325,818	4,679	114,817	7,405	26,164	29,644		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	476,929	225,195	4,672	155,257	10,542	36,173	37,886		2,689	48%
Total		989,041	551,013	9,352	270,073	17,947	62,337	67,530		2,689	
SERP/EDCP		1,772,079									PAY-SEC
- Demand	PAY-SEC-D	956,829	677,874	9,735	238,879	15,407	14,934	-		-	54%
- Customer	PAY-SEC-C	16,829	14,136	200	1,825	3	-	666		-	1%
- Commodity	PAY-SEC-E	798,421	439,958	9,128	303,321	20,596	20,165	-		5,253	45%
Total		1,772,079	1,131,968	19,063	544,025	36,005	35,099	666		5,253	
Advertising removal		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
BGS Administrative Labor included in BGS Deferral		-									AE-ALL
- Demand	DMD-ALL	-	-	-	-	-	-	-		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	-	-	-	-	-	-	-		-	48%
Total		-	-	-	-	-	-	-		-	
Low Income O&M		881,687									AE-ALL
- Demand	DMD-ALL	456,526	290,453	4,171	102,354	6,602	23,324	26,426		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	425,162	200,752	4,165	138,405	9,398	32,247	33,774		2,397	48%
Total		881,687	491,204	8,336	240,759	15,999	55,571	60,200		2,397	
Contract Labor/Fuel Costs		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
Total O&M Adjustment		17,442,819									
- Demand		9,268,772	6,438,895	92,469	2,346,677	152,470	154,128	67,298		9,841	
- Customer		164,874	134,792	2,335	23,000	96	294	4,354		-	
- Commodity		8,009,174	4,428,243	91,380	2,960,766	198,439	193,190	74,599		54,016	
Total		17,442,819	11,001,930	186,185	5,330,443	351,005	347,612	146,251		63,856	
Total O&M Expenses		115,043,159									
- Demand		61,967,794	43,773,972	628,638	15,503,363	1,001,035	976,653	67,298		9,841	
- Customer		1,091,774	913,361	13,354	123,506	242	294	41,015		-	
- Commodity		51,983,591	28,659,708	594,146	19,666,710	1,332,783	1,303,785	74,599		343,319	
Total		**115,043,159**	**73,347,041**	**1,236,138**	**35,293,579**	**2,334,059**	**2,280,732**	**182,912**		**353,160**	
DEPRECIATION EXPENSE											
Depreciation Expense											
(403-360) Land & Land Rights		66,658									AE-SEC
- Demand	DMD-SEC	36,288	26,116	375	9,203	594	-	-		-	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	30,370	17,168	356	11,836	804	-	-		205	46%
Total		66,658	43,284	731	21,040	1,397	-	-		205	
(403-361) Struct & Impmnts		526,520									AE-SEC
- Demand	DMD-SEC	286,633	206,288	2,962	72,695	4,689	-	-		-	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	239,887	135,611	2,814	93,495	6,348	-	-		1,619	46%
Total		526,520	341,899	5,776	166,189	11,037	-	-		1,619	
(403-362) Station Equip		4,393,098									AE-SEC
- Demand	DMD-SEC	2,391,565	1,721,189	24,718	606,538	39,120	-	-		-	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	2,001,533	1,131,492	23,477	780,087	52,968	-	-		13,509	46%
Total		4,393,098	2,852,681	48,195	1,386,625	92,088	-	-		13,509	
(403-364) Poles, Towers & Fixt		9,069,659									AE-SEC
- Demand	DMD-SEC	4,937,445	3,553,438	51,031	1,252,213	80,764	-	-		-	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	4,132,214	2,335,993	48,468	1,610,508	109,354	-	-		27,890	46%
Total		9,069,659	5,889,431	99,499	2,862,721	190,118	-	-		27,890	
(403-365) OH Cond & Dev		20,988,905									AE-SEC
- Demand	DMD-SEC	11,426,181	8,223,326	118,095	2,897,857	186,903	-	-		-	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	9,562,724	5,405,930	112,165	3,727,020	253,067	-	-		64,542	46%
Total		20,988,905	13,629,256	230,260	6,624,877	439,970	-	-		64,542	
(403-366) UG Conduit		110,080									AE-SEC
- Demand	DMD-SEC	59,926	43,129	619	15,198	980	-	-		-	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	50,153	28,352	588	19,547	1,327	-	-		339	46%
Total		110,080	71,481	1,208	34,745	2,307	-	-		339	
(403-367) UG Cond & Dev		6,410,848									AE-SEC
- Demand	DMD-SEC	3,490,011	2,511,731	36,071	885,121	57,088	-	-		-	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	2,920,837	1,651,186	34,260	1,138,380	77,297	-	-		19,714	46%
Total		6,410,848	4,162,918	70,331	2,023,501	134,384	-	-		19,714	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
(403-368) Line Transformers		18,448,452									AE-SEC
- Demand	DMD-SEC	10,043,180	7,227,992	103,801	2,547,107	164,280	-	-		-	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	8,405,272	4,751,607	98,589	3,275,910	222,436	-	-		56,730	46%
Total		18,448,452	11,979,600	202,390	5,823,016	386,717	-	-		56,730	
(403-369) Services		7,940,911									SRVC
- Demand	DMD-SEC	3,970,455	2,857,503	41,037	1,006,969	64,946	-	-		-	50%
- Customer	CUST-SVCS	3,970,455	3,472,405	49,145	448,257	649	-	-		-	50%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		7,940,911	6,329,909	90,182	1,455,226	65,595	-	-		-	
(403-370) Meters		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(403-371) Install on Cust Premise		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(403-373) St Lt & Signal Sys		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(403-374) Asset Ret Costs		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(403-389) Land & Land Rights		244									AE-ALL
- Demand	DMD-ALL	126	80	1	28	2	6	7		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	118	55	1	38	3	9	9		1	48%
Total		244	136	2	67	4	15	17		1	
(403-390) Struct & Impmnts -		774,213									AE-ALL
- Demand	DMD-ALL	400,877	255,048	3,663	89,877	5,797	20,481	23,205		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	373,336	176,281	3,658	121,534	8,252	28,316	29,657		2,105	48%
Total		774,213	431,329	7,320	211,411	14,049	48,797	52,862		2,105	
(403-391) Office Furn & Equip		3,821,378									AE-ALL
- Demand	DMD-ALL	1,978,658	1,258,870	18,079	443,619	28,612	101,092	114,536		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	1,842,720	870,091	18,053	599,868	40,731	139,762	146,381		10,388	48%
Total		3,821,378	2,128,961	36,132	1,043,487	69,343	240,854	260,917		10,388	
(403-392) Transportation Equip		887,409									AE-ALL
- Demand	DMD-ALL	459,488	292,338	4,198	103,018	6,644	23,476	26,598		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	427,920	202,054	4,192	139,303	9,459	32,456	33,993		2,412	48%
Total		887,409	494,392	8,391	242,321	16,103	55,932	60,591		2,412	
(403-393) Stores Equip		11,610									AE-ALL
- Demand	DMD-ALL	6,012	3,825	55	1,348	87	307	348		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	5,599	2,643	55	1,823	124	425	445		32	48%
Total		11,610	6,468	110	3,170	211	732	793		32	
(403-394) Tools, Shop & Garage Equip		533,038									AE-ALL
- Demand	DMD-ALL	276,000	175,598	2,522	61,880	3,991	14,101	15,976		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	257,038	121,368	2,518	83,675	5,682	19,495	20,418		1,449	48%
Total		533,038	296,965	5,040	145,554	9,673	33,596	36,395		1,449	
(403-395) Laboratory Equip		10,935									AE-ALL
- Demand	DMD-ALL	5,662	3,602	52	1,269	82	289	328		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	5,273	2,490	52	1,717	117	400	419		30	48%
Total		10,935	6,092	103	2,986	198	689	747		30	
(403-396) Power Operated Equip		33,347									AE-ALL
- Demand	DMD-ALL	17,267	10,985	158	3,871	250	882	999		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	16,080	7,593	158	5,235	355	1,220	1,277		91	48%
Total		33,347	18,578	315	9,106	605	2,102	2,277		91	
(403-397) Communication Equip		1,887,133									AE-ALL
- Demand	DMD-ALL	977,132	621,675	8,928	219,075	14,130	49,923	56,562		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	910,001	429,682	8,915	296,236	20,115	69,020	72,288		5,130	48%
Total		1,887,133	1,051,357	17,843	515,311	34,244	118,942	128,850		5,130	
(403-398) MISC Equip		(9,875)									AE-ALL
- Demand	DMD-ALL	(5,113)	(3,253)	(47)	(1,146)	(74)	(261)	(296)		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(4,762)	(2,249)	(47)	(1,550)	(105)	(361)	(378)		(27)	48%
Total		(9,875)	(5,502)	(93)	(2,697)	(179)	(622)	(674)		(27)	
Total Depreciation Expense		75,904,563									
- Demand		40,757,794	28,989,480	416,318	10,215,741	658,883	210,297	238,264		-	
- Customer		3,970,455	3,472,405	49,145	448,257	649	-	-		-	
- Commodity		31,176,313	17,267,349	358,271	11,904,661	808,334	290,741	304,509		206,158	
Total		75,904,563	49,729,234	823,734	22,568,658	1,467,865	501,037	542,773		206,158	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	Lighting LTG	Classification Factor
Depreciation Adjustment										
Adjustment										
Annualize Deprec Exp		5,061,087								DPR-TOT-SEC
- Demand	DPR-TOT-SEC-D	2,717,607	1,932,931	27,759	681,155	43,932	14,022	15,887	-	54%
- Customer	DPR-TOT-SEC-C	264,738	231,530	3,277	29,888	43	-	-	-	5%
- Commodity	DPR-TOT-SEC-E	2,078,743	1,151,335	23,888	793,767	53,897	19,386	20,304	13,746	41%
Total		5,061,087	3,315,795	54,924	1,504,810	97,873	33,408	36,190	13,746	
Average Net Salvage		2,469,789								DISTPLT-SEC
- Demand	DISTPLT-SEC-D	1,327,649	955,498	13,722	336,712	21,717	-	-	-	54%
- Customer	DISTPLT-SEC-C	190,161	166,307	2,354	21,469	31	-	-	-	8%
- Commodity	DISTPLT-SEC-E	951,979	538,166	11,166	371,029	25,193	-	-	6,425	39%
Total		2,469,789	1,659,971	27,242	729,210	46,941	-	-	6,425	
Total Depreciation Adjustment		7,530,876								
- Demand		4,045,256	2,888,429	41,481	1,017,867	65,649	14,022	15,887	-	
- Customer		454,899	397,837	5,631	51,357	74	-	-	-	
- Commodity		3,030,722	1,689,501	35,055	1,164,796	79,090	19,386	20,304	20,171	
Total		7,530,876	4,975,766	82,166	2,234,020	144,814	33,408	36,190	20,171	
Total Depreciation Expense										
- Demand		44,803,050	31,877,909	457,799	11,233,608	724,532	224,319	254,151	-	
- Customer		4,425,354	3,870,242	54,776	499,614	723	-	-	-	
- Commodity		34,207,035	18,956,850	393,325	13,069,456	887,424	310,126	324,813	226,329	
Total		**83,435,439**	**54,705,000**	**905,900**	**24,802,678**	**1,612,679**	**534,445**	**578,964**	**226,329**	
Amortization, Accretion, Regulatory Debits and Credits										
Amort - Ltd Term Elec Prpty		6,961,838								DISTPLT-SEC
- Demand	DISTPLT-SEC-D	3,742,375	2,693,356	38,679	949,125	61,216	-	-	-	54%
- Customer	DISTPLT-SEC-C	536,025	468,787	6,635	60,516	88	-	-	-	8%
- Commodity	DISTPLT-SEC-E	2,683,437	1,516,981	31,475	1,045,855	71,014	-	-	18,111	39%
Total		6,961,838	4,679,124	76,789	2,055,496	132,317	-	-	18,111	
Accretion Expense		225,877								AE-ALL
- Demand	DMD-ALL	116,956	74,410	1,069	26,222	1,691	5,975	6,770	-	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	108,921	51,430	1,067	35,457	2,408	8,261	8,652	614	48%
Total		225,877	125,840	2,136	61,679	4,099	14,237	15,422	614	
Regulatory Debits		36,620,730								AE-ALL
- Demand	DMD-ALL	18,961,722	12,063,906	173,250	4,251,258	274,193	968,776	1,097,613	-	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	17,659,009	8,338,183	173,004	5,748,609	390,334	1,339,357	1,402,787	99,551	48%
Total		36,620,730	20,402,089	346,254	9,999,866	664,527	2,308,133	2,500,400	99,551	
Regulatory Credits		15,253								AE-ALL
- Demand	DMD-ALL	7,898	5,025	72	1,771	114	404	457	-	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	7,355	3,473	72	2,394	163	558	584	41	48%
Total		15,253	8,498	144	4,165	277	961	1,041	41	
Total Depreciation and Amortization		127,259,138								
- Demand		67,632,001	46,714,606	670,869	16,461,983	1,061,746	1,199,473	1,358,991	-	
- Customer		4,961,379	4,339,029	61,411	560,130	810	-	-	-	
- Commodity		54,665,757	28,866,917	598,944	19,901,772	1,351,342	1,658,303	1,736,837	344,647	
Total		**127,259,138**	**79,920,551**	**1,331,223**	**36,923,885**	**2,413,899**	**2,857,776**	**3,095,828**	**344,647**	
TAXES										
Taxes Other than Income										
(408) Payroll Taxes		1,246,572								PAY-SEC
- Demand	PAY-SEC-D	673,083	476,852	6,848	168,040	10,838	10,505	-	-	54%
- Customer	PAY-SEC-C	11,839	9,944	141	1,284	2	-	468	-	1%
- Commodity	PAY-SEC-E	561,651	309,489	6,421	213,372	14,488	14,185	-	3,695	45%
Total		1,246,572	796,285	13,410	382,696	25,328	24,690	468	3,695	
(408) Property Taxes		3,006,641								RB-SEC
- Demand	RB-SEC-D	1,616,479	1,156,319	16,606	407,481	26,281	5,081	4,204	-	54%
- Customer	RB-SEC-C	179,365	156,812	2,219	20,243	29	-	61	-	6%
- Commodity	RB-SEC-E	1,210,797	677,134	14,049	466,838	31,699	6,980	5,373	8,084	40%
Total		3,006,641	1,990,265	32,875	894,561	58,009	12,061	9,638	8,084	
Total Taxes Other than Income		4,253,214								
- Demand		2,289,563	1,633,170	23,454	575,521	37,119	15,586	4,204	-	
- Customer		191,203	166,756	2,360	21,527	31	-	529	-	
- Commodity		1,772,447	986,623	20,471	680,209	46,187	21,165	5,373	11,779	
Total Taxes Other than Income		**4,253,214**	**2,786,550**	**46,285**	**1,277,257**	**83,337**	**36,751**	**10,106**	**11,779**	
Total Expenses		**246,555,511**								
- Demand		**131,889,358**	**92,121,748**	**1,322,961**	**32,540,867**	**2,099,900**	**2,191,712**	**1,430,492**	**9,841**	
- Customer		**6,244,357**	**5,419,145**	**77,125**	**705,163**	**1,083**	**294**	**41,544**	**-**	
- Commodity		**108,421,796**	**58,513,248**	**1,213,561**	**40,248,692**	**2,730,312**	**2,983,253**	**1,816,809**	**699,745**	
Total		**246,555,511**	**156,054,142**	**2,613,646**	**73,494,721**	**4,831,295**	**5,175,259**	**3,288,846**	**709,586**	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
REVENUE REQUIREMENT CALCULATION											
Total Rate Base											
- Demand		866,871,761	620,100,689	8,905,267	218,520,242	14,093,868	2,724,619	2,254,460		-	
- Customer		96,188,288	84,093,879	1,190,185	10,855,769	15,705	-	32,750		-	
- Commodity		649,315,706	363,127,469	7,534,333	250,351,650	16,999,029	3,743,123	2,881,277		4,335,436	
Total		1,612,375,756	1,067,322,037	17,629,786	479,727,660	31,108,603	6,467,742	5,168,487		4,335,436	
Required Net Income											
- Demand		65,882,254	47,127,652	676,800	16,607,538	1,071,134	207,071	171,339		-	
- Customer		7,310,310	6,391,135	90,454	825,038	1,194	-	2,489		-	
- Commodity		49,347,994	27,597,688	572,609	19,026,725	1,291,926	284,477	218,977		329,493	
Total		122,540,557	81,116,475	1,339,864	36,459,302	2,364,254	491,548	392,805		329,493	
Interest Synchronization											
- Demand		19,063,654	13,636,833	195,839	4,805,549	309,943	59,918	49,579		-	
- Customer		2,115,307	1,849,335	26,174	238,733	345	-	720		-	
- Commodity		14,279,309	7,985,652	165,690	5,505,563	373,831	82,316	63,363		95,342	
Total		35,458,271	23,471,820	387,702	10,549,844	684,119	142,234	113,662		95,342	
Net Income Before Income Taxes											
- Demand		46,818,600	33,490,820	480,962	11,801,990	761,191	147,153	121,760		-	
- Customer		5,195,003	4,541,799	64,280	586,306	848	-	1,769		-	
- Commodity		35,068,684	19,612,035	406,919	13,521,162	918,095	202,161	155,614		234,151	
Total		87,082,286	57,644,654	952,161	25,909,458	1,680,135	349,314	279,143		234,151	
Taxable Income											
- Demand		65,125,330	46,586,201	669,025	16,416,734	1,058,828	204,692	169,370		-	
- Customer		7,226,321	6,317,707	89,415	815,560	1,180	-	2,460		-	
- Commodity		48,781,033	27,280,617	566,031	18,808,127	1,277,083	281,209	216,461		325,708	
Total		121,132,684	80,184,524	1,324,470	36,040,420	2,337,091	485,901	388,292		325,708	
NJ State Corporate Business Tax											
- Demand		5,861,280	4,192,758	60,212	1,477,506	95,294	18,422	15,243		-	
- Customer		650,369	568,594	8,047	73,400	106	-	221		-	
- Commodity		4,390,293	2,455,255	50,943	1,692,731	114,937	25,309	19,482		29,314	
Total		10,901,942	7,216,607	119,202	3,243,638	210,338	43,731	34,946		29,314	
Federal Taxable Income											
- Demand		59,264,050	42,393,443	608,812	14,939,228	963,533	186,270	154,127		-	
- Customer		6,575,953	5,749,113	81,368	742,159	1,074	-	2,239		-	
- Commodity		44,390,740	24,825,361	515,088	17,115,395	1,162,146	255,900	196,980		296,394	
Total		110,230,742	72,967,917	1,205,268	32,796,782	2,126,753	442,170	353,346		296,394	
Federal Income Tax											
- Demand		12,445,451	8,902,623	127,851	3,137,238	202,342	39,117	32,367		-	
- Customer		1,380,950	1,207,314	17,087	155,853	225	-	470		-	
- Commodity		9,322,055	5,213,326	108,168	3,594,233	244,051	53,739	41,366		62,243	
Total		23,148,456	15,323,263	253,106	6,887,324	446,618	92,856	74,203		62,243	
NJ Federal & State Income Tax		34,050,397									
- Demand		18,306,730	13,095,381	188,063	4,614,744	297,636	57,539	47,610		-	
- Customer		2,031,319	1,775,907	25,135	229,254	332	-	692		-	
- Commodity		13,712,348	7,668,581	159,111	5,286,964	358,988	79,048	60,847		91,556	
Total		34,050,397	22,539,870	372,309	10,130,962	656,956	136,587	109,149		91,556	
Tax Reform Amortization		(4,995,178)									RB-SEC
- Demand	RB-SEC-D	(2,685,589)	(1,921,087)	(27,589)	(676,981)	(43,663)	(8,441)	(6,984)		-	54%
- Customer	RB-SEC-C	(297,994)	(260,525)	(3,687)	(33,631)	(49)	-	(101)		-	6%
- Commodity	RB-SEC-E	(2,011,595)	(1,124,978)	(23,342)	(775,595)	(52,663)	(11,596)	(8,926)		(13,431)	40%
Total		(4,995,178)	(3,306,589)	(54,617)	(1,486,208)	(96,375)	(20,037)	(16,012)		(13,431)	
Investment Tax Credit		(72,848)									RB-SEC
- Demand	RB-SEC-D	(39,166)	(28,017)	(402)	(9,873)	(637)	(123)	(102)		-	54%
- Customer	RB-SEC-C	(4,346)	(3,799)	(54)	(490)	(1)	-	(1)		-	6%
- Commodity	RB-SEC-E	(29,337)	(16,406)	(340)	(11,311)	(768)	(169)	(130)		(196)	40%
Total		(72,848)	(48,222)	(797)	(21,674)	(1,406)	(292)	(234)		(196)	
Federal & State Income Taxes											
- Demand		15,581,975	11,146,278	160,072	3,927,890	253,337	48,975	40,524		-	
- Customer		1,728,980	1,511,583	21,394	195,132	282	-	589		-	
- Commodity		11,671,416	6,527,197	135,429	4,500,058	305,557	67,282	51,791		77,929	
Total		28,982,371	19,185,058	316,894	8,623,080	559,176	116,257	92,903		77,929	
Revenue Requirement											
- Demand		**213,353,587**	**150,395,679**	**2,159,833**	**53,076,295**	**3,424,371**	**2,447,758**	**1,642,355**		**9,841**	
- Customer		**15,283,646**	**13,321,863**	**188,972**	**1,725,333**	**2,559**	**294**	**44,622**		**-**	
- Commodity		**169,441,206**	**92,638,133**	**1,921,599**	**63,775,475**	**4,327,795**	**3,335,013**	**2,087,577**		**1,107,167**	
Total		**398,078,439**	**256,355,675**	**4,270,404**	**118,577,103**	**7,754,725**	**5,783,065**	**3,774,554**		**1,117,008**	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG	Classification Factor
UTILITY PLANT											
Intangible Plant											
(301) Organizational Costs		4,639									AE-ALL
- Demand	DMD-ALL	2,402	1,528	22	539	35	123	139		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	2,237	1,056	22	728	49	170	178		13	48%
Total		4,639	2,584	44	1,267	84	292	317		13	
(302) Franchises & Consents		246									AE-ALL
- Demand	DMD-ALL	128	81	1	29	2	7	7		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	119	56	1	39	3	9	9		1	48%
Total		246	137	2	67	4	16	17		1	
(303) Misc. Intangible Plant		16,378,987									AE-ALL
- Demand	DMD-ALL	8,480,819	5,395,702	77,488	1,901,417	122,635	433,295	490,918		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	7,898,168	3,729,335	77,378	2,571,123	174,581	599,041	627,410		44,525	48%
Total		16,378,987	9,125,038	154,866	4,472,540	297,216	1,032,336	1,118,329		44,525	
Total Intangible Plant		16,383,872									
- Demand		8,483,349	5,397,312	77,511	1,901,984	122,672	433,424	491,065		-	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		7,900,524	3,730,448	77,401	2,571,889	174,633	599,220	627,598		44,538	
Total		16,383,872	9,127,759	154,912	4,473,874	297,305	1,032,644	1,118,662		44,538	
Distribution Plant											
(360) Land and Land Rights		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(361) Structures and Improvements		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(362) Station Equipment		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(364) Poles, Towers & Fixtures		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(365) Overhead Conductors & Devices		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(366) Underground Conduit		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(367) Underground Conductors & Device		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(368) Line Transformers		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(369) Services		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(370) Meters		200,512,098									MTR
- Demand	DMD-MTR	89,218,324	40,573,392	4,322,404	43,918,093	404,434	-	-		-	44%
- Customer	CUST-MTR	111,293,775	84,960,239	1,141,623	10,675,430	235,477	7,208,935	6,995,765		-	56%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		200,512,098	125,533,631	5,464,028	54,593,524	639,911	7,208,935	6,995,765		-	
(371) Installation on Customers' Premises		27,149,890									DEM
- Demand	DMD-LTG	27,149,890	-	-	-	-	-	-		27,149,890	100%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		27,149,890	-	-	-	-	-	-		27,149,890	
(373) Street Lighting & Signal Systems		265,095,805									DEM
- Demand	DMD-LTG	265,095,805	-	-	-	-	-	-		265,095,805	100%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		265,095,805	-	-	-	-	-	-		265,095,805	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
(374) Asset Retirement Costs		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(375) Charging Stations		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
Total Distribution Plant		492,757,793									
- Demand		381,464,018	40,573,392	4,322,404	43,918,093	404,434	-	-		292,245,694	
- Customer		111,293,775	84,960,239	1,141,623	10,675,430	235,477	7,208,935	6,995,765		-	
- Commodity		-	-	-	-	-	-	-		-	
Total		492,757,793	125,533,631	5,464,028	54,593,524	639,911	7,208,935	6,995,765		292,245,694	
General Plant											
(389) Land and Land Rights		431,335									AE-ALL
- Demand	DMD-ALL	223,340	142,094	2,041	50,073	3,230	11,411	12,928		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	207,996	98,211	2,038	67,710	4,598	15,776	16,523		1,173	48%
Total		431,335	240,305	4,078	117,783	7,827	27,186	29,451		1,173	
(390) Structures and Improvements		30,492,179									AE-ALL
- Demand	DMD-ALL	15,788,440	10,044,988	144,256	3,539,801	228,306	806,649	913,925		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	14,703,739	6,942,771	144,052	4,786,568	325,011	1,115,213	1,168,028		82,891	48%
Total		30,492,179	16,987,759	288,308	8,326,369	553,317	1,921,863	2,081,953		82,891	
(391) Office Furniture & Equipment		10,346,704									AE-ALL
- Demand	DMD-ALL	5,357,384	3,408,497	48,949	1,201,137	77,470	273,715	310,116		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	4,989,320	2,355,843	48,880	1,624,193	110,284	378,418	396,339		28,127	48%
Total		10,346,704	5,764,341	97,830	2,825,330	187,753	652,133	706,455		28,127	
(392) Transportation Equipment		5,024,096									AE-ALL
- Demand	DMD-ALL	2,601,409	1,655,079	23,769	583,241	37,617	132,909	150,584		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	2,422,686	1,143,937	23,735	788,667	53,551	183,750	192,452		13,658	48%
Total		5,024,096	2,799,017	47,504	1,371,908	91,168	316,659	343,037		13,658	
(393) Stores Equipment		322,950									AE-ALL
- Demand	DMD-ALL	167,219	106,389	1,528	37,491	2,418	8,543	9,680		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	155,731	73,533	1,526	50,696	3,442	11,812	12,371		878	48%
Total		322,950	179,922	3,054	88,187	5,860	20,355	22,050		878	
(394) Tools, Shop & Garage Equipment		6,961,084									AE-ALL
- Demand	DMD-ALL	3,604,355	2,293,178	32,932	808,104	52,120	184,151	208,641		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	3,356,728	1,584,971	32,886	1,092,729	74,197	254,593	266,650		18,923	48%
Total		6,961,084	3,878,149	65,818	1,900,833	126,317	438,744	475,291		18,923	
(395) Laboratory Equipment		123,099									AE-ALL
- Demand	DMD-ALL	63,739	40,552	582	14,290	922	3,257	3,690		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	59,360	28,028	582	19,324	1,312	4,502	4,715		335	48%
Total		123,099	68,581	1,164	33,614	2,234	7,759	8,405		335	
(396) Power Operated Equipment		590,436									AE-ALL
- Demand	DMD-ALL	305,720	194,507	2,793	68,543	4,421	15,620	17,697		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	284,716	134,437	2,789	92,685	6,293	21,594	22,617		1,605	48%
Total		590,436	328,943	5,583	161,228	10,714	37,214	40,314		1,605	
(397) Communication Equipment		18,782,145									AE-ALL
- Demand	DMD-ALL	9,725,142	6,187,371	88,857	2,180,397	140,629	496,868	562,947		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	9,057,003	4,276,511	88,731	2,948,363	200,196	686,934	719,465		51,058	48%
Total		18,782,145	10,463,882	177,588	5,128,760	340,824	1,183,802	1,282,412		51,058	
(398) Misc. Equipment		50,617									AE-ALL
- Demand	DMD-ALL	26,209	16,675	239	5,876	379	1,339	1,517		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	24,408	11,525	239	7,946	540	1,851	1,939		138	48%
Total		50,617	28,200	479	13,822	919	3,190	3,456		138	
(399) Other Tangible Property		420,880									AE-ALL
- Demand	DMD-ALL	217,926	138,650	1,991	48,859	3,151	11,134	12,615		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	202,954	95,830	1,988	66,068	4,486	15,393	16,122		1,144	48%
Total		420,880	234,480	3,979	114,928	7,637	26,527	28,737		1,144	
(SRVCO-PIS) Service Company PIS		40,249,742									AE-ALL
- Demand	DMD-ALL	20,840,775	13,259,405	190,418	4,672,545	301,364	1,064,779	1,206,383		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	19,408,967	9,164,473	190,149	6,318,280	429,015	1,472,084	1,541,799		109,416	48%
Total		40,249,742	22,423,878	380,567	10,990,825	730,380	2,536,863	2,748,182		109,416	
Total General Plant		113,795,268									
- Demand		58,921,659	37,487,385	538,356	13,210,359	852,027	3,010,374	3,410,722		-	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		54,873,609	25,910,071	537,594	17,863,229	1,212,924	4,161,920	4,359,020		309,344	
Total		113,795,268	63,397,456	1,075,950	31,073,587	2,064,951	7,172,294	7,769,743		309,344	
Total Utility Plant		622,936,932									
- Demand		448,869,025	83,458,089	4,938,272	59,030,437	1,379,133	3,443,798	3,901,787		292,245,694	
- Customer		111,293,775	84,960,239	1,141,623	10,675,430	235,477	7,208,935	6,995,765		-	
- Commodity		62,774,133	29,640,518	614,995	20,435,118	1,387,557	4,761,140	4,986,618		353,883	
Total		622,936,932	198,058,846	6,694,890	90,140,985	3,002,167	15,413,872	15,884,171		292,599,577	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
Additions to Utility Plant											
Construction Work in Progress		-									
- Demand		-	-	-	-	-	-	-		-	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		-	-	-	-	-	-	-		-	
Total		-	-	-	-	-	-	-		-	
Total Additional to Utility Plant		-									
- Demand		-	-	-	-	-	-	-		-	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		-	-	-	-	-	-	-		-	
Total		-	-	-	-	-	-	-		-	
Total Utility Plant		622,936,932									
- Demand		448,869,025	83,458,089	4,938,272	59,030,437	1,379,133	3,443,798	3,901,787		292,245,694	
- Customer		111,293,775	84,960,239	1,141,623	10,675,430	235,477	7,208,935	6,995,765		-	
- Commodity		62,774,133	29,640,518	614,995	20,435,118	1,387,557	4,761,140	4,986,618		353,883	
Total		**622,936,932**	**198,058,846**	**6,694,890**	**90,140,985**	**3,002,167**	**15,413,872**	**15,884,171**		**292,599,577**	
ACCUMULATED DEPRECIATION											
Accumulated Depreciation											
(108-303) Misc Intangible Plant		(11,957,177)									AE-ALL
- Demand	DMD-ALL	(6,191,265)	(3,939,033)	(56,568)	(1,388,095)	(89,528)	(316,319)	(358,386)		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(5,765,912)	(2,722,532)	(56,488)	(1,877,001)	(127,449)	(437,319)	(458,029)		(32,505)	48%
Total		(11,957,177)	(6,661,565)	(113,057)	(3,265,095)	(216,977)	(753,638)	(816,415)		(32,505)	
(108-360) Land & Land Rights		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(108-361) Struct & Impmnts		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(108-362) Station Equip		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(108-364) Poles, Towers & Fixt		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(108-365) OH Cond & Dev		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(108-366) UG Conduit		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(108-367) UG Cond & Dev		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(108-368) Line Transformers		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(108-369) Services		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(108-370) Meters		(67,885,351)									MTR
- Demand	DMD-MTR	(30,205,744)	(13,736,522)	(1,463,393)	(14,868,904)	(136,925)	-	-		-	44%
- Customer	CUST-MTR	(37,679,606)	(28,764,128)	(386,508)	(3,614,272)	(79,723)	(2,440,656)	(2,368,485)		-	56%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		(67,885,351)	(42,500,650)	(1,849,901)	(18,483,176)	(216,648)	(2,440,656)	(2,368,485)		-	
(108-371) Install on Cust Premise		(10,069,793)									DEM
- Demand	DMD-LTG	(10,069,793)	-	-	-	-	-	-		(10,069,793)	100%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		(10,069,793)	-	-	-	-	-	-		(10,069,793)	
(108-373) St Lt & Signal Sys		(99,523,237)									DEM
- Demand	DMD-LTG	(99,523,237)	-	-	-	-	-	-		(99,523,237)	100%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		(99,523,237)	-	-	-	-	-	-		(99,523,237)	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
(108-374) Asset Ret Costs		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(108-389) Land & Land Rights		(649)									AE-ALL
- Demand	DMD-ALL	(336)	(214)	(3)	(75)	(5)	(17)	(19)		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(313)	(148)	(3)	(102)	(7)	(24)	(25)		(2)	48%
Total		(649)	(362)	(6)	(177)	(12)	(41)	(44)		(2)	
(108-390) Struct & Impmnts -		(5,272,594)									AE-ALL
- Demand	DMD-ALL	(2,730,078)	(1,736,942)	(24,944)	(612,089)	(39,478)	(139,483)	(158,033)		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(2,542,516)	(1,200,518)	(24,909)	(827,675)	(56,200)	(192,839)	(201,971)		(14,333)	48%
Total		(5,272,594)	(2,937,460)	(49,853)	(1,439,765)	(95,677)	(332,321)	(360,004)		(14,333)	
(108-391) Office Furn & Equip		(588,664)									AE-ALL
- Demand	DMD-ALL	(304,802)	(193,923)	(2,785)	(68,337)	(4,408)	(15,573)	(17,644)		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(283,862)	(134,033)	(2,781)	(92,407)	(6,274)	(21,530)	(22,549)		(1,600)	48%
Total		(588,664)	(327,956)	(5,566)	(160,744)	(10,682)	(37,102)	(40,193)		(1,600)	
(108-392) Transportation Equip		(485,586)									AE-ALL
- Demand	DMD-ALL	(251,430)	(159,966)	(2,297)	(56,371)	(3,636)	(12,846)	(14,554)		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(234,156)	(110,563)	(2,294)	(76,226)	(5,176)	(17,760)	(18,601)		(1,320)	48%
Total		(485,586)	(270,529)	(4,591)	(132,597)	(8,812)	(30,606)	(33,155)		(1,320)	
(108-393) Stores Equip		(89,984)									AE-ALL
- Demand	DMD-ALL	(46,593)	(29,643)	(426)	(10,446)	(674)	(2,380)	(2,697)		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(43,392)	(20,489)	(425)	(14,125)	(959)	(3,291)	(3,447)		(245)	48%
Total		(89,984)	(50,132)	(851)	(24,572)	(1,633)	(5,672)	(6,144)		(245)	
(108-394) Tools, Shop & Garage Equip		(1,006,037)									AE-ALL
- Demand	DMD-ALL	(520,912)	(331,417)	(4,759)	(116,790)	(7,533)	(26,614)	(30,153)		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(485,125)	(229,065)	(4,753)	(157,925)	(10,723)	(36,795)	(38,537)		(2,735)	48%
Total		(1,006,037)	(560,482)	(9,512)	(274,714)	(18,256)	(63,409)	(68,690)		(2,735)	
(108-395) Laboratory Equip		(39,345)									AE-ALL
- Demand	DMD-ALL	(20,372)	(12,961)	(186)	(4,567)	(295)	(1,041)	(1,179)		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(18,973)	(8,958)	(186)	(6,176)	(419)	(1,439)	(1,507)		(107)	48%
Total		(39,345)	(21,920)	(372)	(10,744)	(714)	(2,480)	(2,686)		(107)	
(108-396) Power Operated Equip		(112,921)									AE-ALL
- Demand	DMD-ALL	(58,469)	(37,199)	(534)	(13,109)	(845)	(2,987)	(3,385)		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(54,452)	(25,711)	(533)	(17,726)	(1,204)	(4,130)	(4,326)		(307)	48%
Total		(112,921)	(62,910)	(1,068)	(30,835)	(2,049)	(7,117)	(7,710)		(307)	
(108-397) Communication Equip		(1,230,582)									AE-ALL
- Demand	DMD-ALL	(637,179)	(405,388)	(5,822)	(142,857)	(9,214)	(32,554)	(36,884)		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(593,403)	(280,191)	(5,814)	(193,173)	(13,117)	(45,007)	(47,138)		(3,345)	48%
Total		(1,230,582)	(685,580)	(11,635)	(336,030)	(22,330)	(77,561)	(84,022)		(3,345)	
(108-398) MISC Equip		(20,143)									AE-ALL
- Demand	DMD-ALL	(10,430)	(6,636)	(95)	(2,338)	(151)	(533)	(604)		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(9,713)	(4,586)	(95)	(3,162)	(215)	(737)	(772)		(55)	48%
Total		(20,143)	(11,222)	(190)	(5,500)	(366)	(1,270)	(1,375)		(55)	
(108-399) Other Tangible Property		-									AE-ALL
- Demand	DMD-ALL	-	-	-	-	-	-	-		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	-	-	-	-	-	-	-		-	48%
Total		-	-	-	-	-	-	-		-	
Service Company PIS		(9,181,627)									AE-ALL
- Demand	DMD-ALL	(4,754,123)	(3,024,688)	(43,438)	(1,065,884)	(68,746)	(242,893)	(275,196)		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(4,427,504)	(2,090,567)	(43,376)	(1,441,303)	(97,865)	(335,807)	(351,710)		(24,960)	48%
Total		(9,181,627)	(5,115,255)	(86,814)	(2,507,188)	(166,612)	(578,700)	(626,905)		(24,960)	
Total Accumulated Depreciation		(207,463,688)									
- Demand		(155,324,763)	(23,614,532)	(1,605,251)	(18,349,863)	(361,436)	(793,240)	(898,733)		(109,593,030)	
- Customer		(37,679,606)	(28,764,128)	(386,508)	(3,614,272)	(79,723)	(2,440,656)	(2,368,485)		-	
- Commodity		(14,459,319)	(6,827,362)	(141,657)	(4,707,001)	(319,608)	(1,096,675)	(1,148,612)		(81,513)	
Total Accumulated Depreciation		**(207,463,688)**	**(59,206,022)**	**(2,133,416)**	**(26,671,136)**	**(760,767)**	**(4,330,571)**	**(4,415,830)**		**(109,674,543)**	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG	Classification Factor
OTHER RATE BASE ITEMS											
Other Rate Base Items											
Materials and Supplies		2,690,264									DISTPLT-CS
- Demand	DISTPLT-CS-D	2,082,644	221,515	23,599	239,776	2,208	-	-		1,595,547	77%
- Customer	DISTPLT-CS-C	607,620	463,850	6,233	58,284	1,286	39,358	38,194		-	23%
- Commodity	DISTPLT-CS-E	-	-	-	-	-	-	-		-	0%
Total		2,690,264	685,364	29,831	298,059	3,494	39,358	38,194		1,595,547	
Cash Working Capital		31,703,994									CWC-CS
- Demand	CWC-CS-D	15,885,262	6,521,730	504,523	5,552,443	91,348	165,758	-		3,049,460	50%
- Customer	CWC-CS-C	12,227,261	9,334,134	125,424	1,172,853	25,871	792,008	768,588		-	39%
- Commodity	CWC-CS-E	3,591,472	2,079,061	41,238	1,140,964	69,165	232,580	8,394		19,178	11%
Total		31,703,994	17,934,925	671,185	7,866,261	186,383	1,190,346	776,982		3,068,638	
ADIT		(122,976,343)									DISTPLT-CS
- Demand	DISTPLT-CS-D	(95,201,031)	(10,125,801)	(1,078,732)	(10,960,530)	(100,934)	-	-		(72,935,035)	77%
- Customer	DISTPLT-CS-C	(27,775,312)	(21,203,316)	(284,912)	(2,664,241)	(58,767)	(1,799,116)	(1,745,916)		-	23%
- Commodity	DISTPLT-CS-E	-	-	-	-	-	-	-		-	0%
Total		(122,976,343)	(31,329,117)	(1,363,644)	(13,624,771)	(159,701)	(1,799,116)	(1,745,916)		(72,935,035)	
Net /Loss on Reacq Debt		140,919									DISTPLT-CS
- Demand	DISTPLT-CS-D	109,091	11,603	1,236	12,560	116	-	-		83,576	77%
- Customer	DISTPLT-CS-C	31,828	24,297	326	3,053	67	2,062	2,001		-	23%
- Commodity	DISTPLT-CS-E	-	-	-	-	-	-	-		-	0%
Total		140,919	35,900	1,563	15,613	183	2,062	2,001		83,576	
DTA for AMT		977,993									DISTPLT-CS
- Demand	DISTPLT-CS-D	757,104	80,527	8,579	87,166	803	-	-		580,030	77%
- Customer	DISTPLT-CS-C	220,888	168,623	2,266	21,188	467	14,308	13,885		-	23%
- Commodity	DISTPLT-CS-E	-	-	-	-	-	-	-		-	0%
Total		977,993	249,151	10,845	108,354	1,270	14,308	13,885		580,030	
Net Operating Reserves		(960,990)									PAY-CS
- Demand	PAY-CS-D	(488,515)	(235,785)	(12,645)	(156,422)	(4,077)	(10,868)	-		(68,719)	51%
- Customer	PAY-CS-C	(275,855)	(210,342)	(2,826)	(26,430)	(583)	(17,848)	(17,638)		-	29%
- Commodity	PAY-CS-E	(196,620)	(106,806)	(2,173)	(67,046)	(4,365)	(14,872)	(189)		(1,148)	20%
Total		(960,990)	(552,933)	(17,644)	(249,898)	(9,025)	(43,587)	(17,827)		(69,867)	
NOL		3,709,005									DISTPLT-CS
- Demand	DISTPLT-CS-D	2,871,293	305,397	32,535	330,573	3,044	-	-		2,199,744	77%
- Customer	DISTPLT-CS-C	837,712	639,499	8,593	80,354	1,772	54,262	52,657		-	23%
- Commodity	DISTPLT-CS-E	-	-	-	-	-	-	-		-	0%
Total		3,709,005	944,896	41,128	410,927	4,817	54,262	52,657		2,199,744	
CTA		(99,089)									TOTPLT-CS
- Demand	TOTPLT-CS-D	(71,401)	(13,276)	(786)	(9,390)	(219)	(548)	(621)		(46,487)	72.0569%
- Customer	TOTPLT-CS-C	(17,703)	(13,514)	(182)	(1,698)	(37)	(1,147)	(1,113)		-	18%
- Commodity	TOTPLT-CS-E	(9,985)	(4,715)	(98)	(3,251)	(221)	(757)	(793)		(56)	10%
Total		(99,089)	(31,505)	(1,065)	(14,339)	(478)	(2,452)	(2,527)		(46,543)	
Regulatory Asset A&G Capitalization		5,643,328									AE-PRI-GTA&G
- Demand	DMD-PRI	2,988,081	2,033,001	29,196	716,419	46,207	163,257	-		-	53%
- Customer	CUST-GTA&G	7,277	-	-	-	-	-	7,277		-	0%
- Commodity	NRG-PRI	2,647,971	1,372,317	28,473	946,119	64,242	220,435	-		16,384	47%
Total		5,643,328	3,405,319	57,669	1,662,538	110,449	383,692	7,277		16,384	
Customer Deposits		(36,962,658)									CUS
- Demand		-	-	-	-	-	-	-		-	0%
- Customer	CUST-DEP	(36,962,658)	(32,304,391)	(457,206)	(4,170,208)	(6,033)	(19,249)	(5,538)		-	100%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		(36,962,658)	(32,304,391)	(457,206)	(4,170,208)	(6,033)	(19,249)	(5,538)		-	
Customer Advances		(5,120,290)									DISTPLT-CS
- Demand	DISTPLT-CS-D	(3,963,827)	(421,602)	(44,914)	(456,357)	(4,203)	-	-		(3,036,751)	77%
- Customer	DISTPLT-CS-C	(1,156,464)	(882,829)	(11,863)	(110,929)	(2,447)	(74,909)	(72,694)		-	23%
- Commodity	DISTPLT-CS-E	-	-	-	-	-	-	-		-	0%
Total		(5,120,290)	(1,304,431)	(56,777)	(567,286)	(6,649)	(74,909)	(72,694)		(3,036,751)	
Customer Refunds		(28,575)									DISTPLT-CS
- Demand	DISTPLT-CS-D	(22,121)	(2,353)	(251)	(2,547)	(23)	-	-		(16,947)	77%
- Customer	DISTPLT-CS-C	(6,454)	(4,927)	(66)	(619)	(14)	(418)	(406)		-	23%
- Commodity	DISTPLT-CS-E	-	-	-	-	-	-	-		-	0%
Total		(28,575)	(7,280)	(317)	(3,166)	(37)	(418)	(406)		(16,947)	
Total Other Rate Base Items		(121,282,442)									
- Demand		(75,053,420)	(1,625,042)	(537,660)	(4,646,309)	34,269	317,600	(621)		(68,595,582)	
- Customer		(52,261,860)	(43,988,918)	(614,213)	(5,638,393)	(38,418)	(1,010,689)	(960,703)		-	
- Commodity		6,032,838	3,339,857	67,440	2,016,787	128,821	437,385	7,412		34,358	
Total		(121,282,442)	(42,274,102)	(1,084,432)	(8,267,916)	124,672	(255,703)	(953,911)		(68,561,224)	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
Rate Base Adjustment											
Adjustment											
AMI		43,720,862									MTR
- Demand	DMD-MTR	19,453,699	8,846,866	942,483	9,576,165	88,185	-	-		-	44%
- Customer	CUST-MTR	24,267,163	18,525,240	248,926	2,327,735	51,345	1,571,879	1,525,399		-	56%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		43,720,862	27,372,106	1,191,409	11,903,900	139,530	1,571,879	1,525,399		-	
Delayed Recognition Pension & OPEB		(10,398,169)									PAY-CS
- Demand	PAY-CS-D	(5,285,865)	(2,551,253)	(136,820)	(1,692,529)	(44,117)	(117,593)	-		(743,554)	51%
- Customer	PAY-CS-C	(2,984,828)	(2,275,953)	(30,582)	(285,978)	(6,308)	(193,116)	(190,846)		-	29%
- Commodity	PAY-CS-E	(2,127,476)	(1,155,669)	(23,515)	(725,457)	(47,234)	(160,915)	(2,047)		(12,422)	20%
Total		(10,398,169)	(5,982,876)	(190,918)	(2,703,964)	(97,658)	(471,624)	(192,892)		(755,975)	
Total Rate Base Adjustment		33,322,692									
- Demand		14,167,834	6,295,613	805,663	7,883,636	44,069	(117,593)	-		(743,554)	
- Customer		21,282,335	16,249,287	218,344	2,041,757	45,037	1,378,763	1,334,553		-	
- Commodity		(2,127,476)	(1,155,669)	(23,515)	(725,457)	(47,234)	(160,915)	(2,047)		(12,422)	
Total		33,322,692	21,389,231	1,000,492	9,199,935	41,872	1,100,255	1,332,506		(755,975)	
Total Rate Base		**327,513,495**									
- Demand		**232,658,676**	**64,514,128**	**3,601,024**	**43,917,900**	**1,096,034**	**2,850,565**	**3,002,434**		**113,313,529**	
- Customer		**42,634,643**	**28,456,480**	**359,247**	**3,464,521**	**162,373**	**5,136,353**	**5,001,130**		**-**	
- Commodity		**52,220,176**	**24,997,345**	**517,263**	**17,019,447**	**1,149,537**	**3,940,934**	**3,843,371**		**294,307**	
Total		**327,513,495**	**117,967,953**	**4,477,534**	**64,401,868**	**2,407,943**	**11,927,852**	**11,846,935**		**113,607,836**	
OPERATIONS & MAINTENANCE EXPENSES											
Distribution Expenses											
Operations Expenses											
(580) Operation Supervision & Engineering		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(581) Load Dispatching		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(582) Station Expenses		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(583) Overhead line expenses		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(584) Underground line expenses		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(585) Street lighting and signal system expenses		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(586) Meter expenses		3,863,627									MTR
- Demand	DMD-MTR	1,719,130	781,801	83,288	846,249	7,793	-	-		-	44%
- Customer	CUST-MTR	2,144,497	1,637,082	21,998	205,703	4,537	138,908	134,800		-	56%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		3,863,627	2,418,882	105,285	1,051,952	12,330	138,908	134,800		-	
(587) Customer installations expenses		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(588) Miscellaneous distribution expenses		2,182,355									DISTPLT-CS
- Demand	DISTPLT-CS-D	1,689,451	179,694	19,143	194,507	1,791	-	-		1,294,315	77%
- Customer	DISTPLT-CS-C	492,905	376,277	5,056	47,280	1,043	31,927	30,983		-	23%
- Commodity	DISTPLT-CS-E	-	-	-	-	-	-	-		-	0%
Total		2,182,355	555,971	24,199	241,787	2,834	31,927	30,983		1,294,315	
(589) Rents		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
Total Dist. Operations Expenses		6,045,983									
- Demand		3,408,581	961,494	102,431	1,040,756	9,584	-	-		1,294,315	
- Customer		2,637,402	2,013,359	27,054	252,983	5,580	170,835	165,783		-	
- Commodity		-	-	-	-	-	-	-		-	
Total		6,045,983	2,974,853	129,485	1,293,739	15,164	170,835	165,783		1,294,315	
Maintenance Expense											
(590) Maintenance Supervision and Engineering		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
(591) Maintenance of Structures		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(592) Maintenance of Station Equipment		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(593) Maintenance of Overhead Lines		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(594) Maintenance of underground lines		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(595) Maintenance of line transformers		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(596) Maintenance of street lighting and signal systems		4,146,141									DEM
- Demand	DMD-LTG	4,146,141	-	-	-	-	-	-		4,146,141	100%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		4,146,141	-	-	-	-	-	-		4,146,141	
(597) Maintenance of meters		4,075,777									MTR
- Demand	DMD-MTR	1,813,526	824,729	87,861	892,716	8,221	-	-		-	44%
- Customer	CUST-MTR	2,262,251	1,726,973	23,206	216,998	4,787	146,535	142,202		-	56%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		4,075,777	2,551,702	111,066	1,109,714	13,007	146,535	142,202		-	
(598) Maintenance of miscellaneous distribution plant		243,395									DISTPLT-CS
- Demand	DISTPLT-CS-D	188,422	20,041	2,135	21,693	200	-	-		144,353	77%
- Customer	DISTPLT-CS-C	54,973	41,966	564	5,273	116	3,561	3,456		-	23%
- Commodity	DISTPLT-CS-E	-	-	-	-	-	-	-		-	0%
Total		243,395	62,007	2,699	26,966	316	3,561	3,456		144,353	
Total Dist. Maintenance Expenses		8,465,313									
- Demand		6,148,090	844,770	89,996	914,409	8,421	-	-		4,290,494	
- Customer		2,317,224	1,768,939	23,769	222,271	4,903	150,096	145,657		-	
- Commodity		-	-	-	-	-	-	-		-	
Total		8,465,313	2,613,709	113,765	1,136,680	13,323	150,096	145,657		4,290,494	
Total Distribution Expenses		14,511,296									
- Demand		9,556,670	1,806,264	192,427	1,955,165	18,005	-	-		5,584,810	
- Customer		4,954,625	3,782,297	50,823	475,254	10,483	320,931	311,441		-	
- Commodity		-	-	-	-	-	-	-		-	
Total		14,511,296	5,588,562	243,250	2,430,419	28,488	320,931	311,441		5,584,810	
Customer Account Expense											
(901) Supervision		42,924									COM
- Demand		-	-	-	-	-	-	-		-	0%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	ALL901	42,924	34,023	605	7,950	99	89	51		107	100%
Total		42,924	34,023	605	7,950	99	89	51		107	
(902) Meter reading expenses		15,227,521									MTR
- Demand	DMD-MTR	6,775,521	3,081,271	328,257	3,335,278	30,714	-	-		-	44%
- Customer	CUST-MTR	8,452,000	6,452,148	86,698	810,726	17,883	547,469	531,280		-	56%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		15,227,521	9,533,420	414,956	4,146,004	48,597	547,469	531,280		-	
(903) Customer records and collection expenses		16,190,497									MTR
- Demand	DMD-MTR	7,203,999	3,276,128	349,016	3,546,199	32,656	-	-		-	44%
- Customer	CUST-MTR	8,986,498	6,860,177	92,181	861,995	19,014	582,091	564,878		-	56%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		16,190,497	10,136,305	441,197	4,408,194	51,670	582,091	564,878		-	
(904) Uncollectible accounts		171,298									COM
- Demand		-	-	-	-	-	-	-		-	0%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	171,298	80,883	1,678	55,763	3,786	12,992	13,607		966	100%
Total		171,298	80,883	1,678	55,763	3,786	12,992	13,607		966	
(905) Miscellaneous customer accounts expenses		1,439,425									COM
- Demand		-	-	-	-	-	-	-		-	0%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	ALL905	1,439,425	1,140,931	20,295	266,584	3,328	2,978	1,715		3,585	100%
Total		1,439,425	1,140,931	20,295	266,584	3,328	2,978	1,715		3,585	
Total Customer Account Expenses		33,071,665									
- Demand		13,979,520	6,357,400	677,273	6,881,477	63,370	-	-		-	
- Customer		17,438,498	13,312,325	178,880	1,672,721	36,897	1,129,560	1,096,159		-	
- Commodity		1,653,647	1,255,836	22,578	330,297	7,214	16,059	15,373		4,658	
Total		33,071,665	20,925,562	878,730	8,884,495	107,481	1,145,619	1,111,532		4,658	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
Customer Service Expenses											
(907) Customer Service Supervision		46,097									AE-PRI
- Demand	DMD-PRI	24,439	16,628	239	5,860	378	1,335	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	21,658	11,224	233	7,738	525	1,803	-		134	47%
Total		46,097	27,852	472	13,598	903	3,138	-		134	
(908) Customer Assistance		2,080,009									AE-PRI
- Demand	DMD-PRI	1,102,764	750,288	10,775	264,398	17,053	60,251	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	977,245	506,460	10,508	349,169	23,709	81,352	-		6,047	47%
Total		2,080,009	1,256,748	21,283	613,567	40,762	141,603	-		6,047	
(909) Informational and instructional advertising		2,645									AE-PRI
- Demand	DMD-PRI	1,402	954	14	336	22	77	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	1,243	644	13	444	30	103	-		8	47%
Total		2,645	1,598	27	780	52	180	-		8	
(910) Miscellaneous customer service and informational		8,351,286									AE-PRI
- Demand	DMD-PRI	4,427,624	3,012,424	43,261	1,061,562	68,467	241,909	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	3,923,662	2,033,447	42,191	1,401,923	95,191	326,631	-		24,278	47%
Total		8,351,286	5,045,871	85,452	2,463,486	163,659	568,540	-		24,278	
Total Customer Service Expenses		10,480,037									
- Demand		5,556,229	3,780,294	54,289	1,332,156	85,920	303,571	-		-	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		4,923,808	2,551,775	52,945	1,759,275	119,456	409,890	-		30,466	
Total		10,480,037	6,332,069	107,234	3,091,431	205,376	713,462	-		30,466	
Sales Expenses											
(911) Sales Exp		4									AE-PRI
- Demand	DMD-PRI	2	1	0	1	0	0	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	2	1	0	1	0	0	-		0	47%
Total		4	2	0	1	0	0	-		0	
Total Sales Expenses		4									
- Demand		2	1	0	1	0	0	-		-	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		2	1	0	1	0	0	-		0	
Total		4	2	0	1	0	0	-		0	
Administrative & General Expense											
Labor Related											
(920) Administrative and general salaries		3,982,779									AE-PRI-GTA&G
- Demand	DMD-PRI	2,108,838	1,434,791	20,605	505,613	32,610	115,219	-		-	53%
- Customer	CUST-GTA&G	5,135	-	-	-	-	-	5,135		-	0%
- Commodity	NRG-PRI	1,868,805	968,513	20,095	667,724	45,339	155,572	-		11,563	47%
Total		3,982,779	2,403,304	40,700	1,173,336	77,949	270,791	5,135		11,563	
(921) Office supplies and expenses		356,264									AE-PRI-GTA&G
- Demand	DMD-PRI	188,638	128,344	1,843	45,228	2,917	10,306	-		-	53%
- Customer	CUST-GTA&G	459	-	-	-	-	-	459		-	0%
- Commodity	NRG-PRI	167,167	86,635	1,798	59,729	4,056	13,916	-		1,034	47%
Total		356,264	214,978	3,641	104,956	6,973	24,223	459		1,034	
(922) Administrative expenses transferred—Credit		(354,702)									AE-PRI-GTA&G
- Demand	DMD-PRI	(187,811)	(127,781)	(1,835)	(45,029)	(2,904)	(10,261)	-		-	53%
- Customer	CUST-GTA&G	(457)	-	-	-	-	-	(457)		-	0%
- Commodity	NRG-PRI	(166,434)	(86,255)	(1,790)	(59,467)	(4,038)	(13,855)	-		(1,030)	47%
Total		(354,702)	(214,036)	(3,625)	(104,496)	(6,942)	(24,116)	(457)		(1,030)	
(923) Outside services employed		12,972,666									AE-PRI-GTA&G
- Demand	DMD-PRI	6,868,885	4,673,385	67,114	1,646,877	106,218	375,290	-		-	53%
- Customer	CUST-GTA&G	16,727	-	-	-	-	-	16,727		-	0%
- Commodity	NRG-PRI	6,087,054	3,154,630	65,454	2,174,903	147,677	506,726	-		37,664	47%
Total		12,972,666	7,828,016	132,568	3,821,779	253,896	882,016	16,727		37,664	
(926) Employee pensions and benefits		(800,946)									AE-PRI-GTA&G
- Demand	DMD-PRI	(424,092)	(288,540)	(4,144)	(101,680)	(6,558)	(23,171)	-		-	53%
- Customer	CUST-GTA&G	(1,033)	-	-	-	-	-	(1,033)		-	0%
- Commodity	NRG-PRI	(375,821)	(194,770)	(4,041)	(134,281)	(9,118)	(31,286)	-		(2,325)	47%
Total		(800,946)	(483,310)	(8,185)	(235,961)	(15,676)	(54,457)	(1,033)		(2,325)	
(426) Pension / OPEB Non-Service Cost		-									AE-PRI-GTA&G
- Demand		-	-	-	-	-	-	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity		-	-	-	-	-	-	-		-	47%
Total		-	-	-	-	-	-	-		-	
(924) Property insurance		24,708									AE-PRI-GTA&G
- Demand	DMD-PRI	13,082	8,901	128	3,137	202	715	-		-	53%
- Customer	CUST-GTA&G	32	-	-	-	-	-	32		-	0%
- Commodity	NRG-PRI	11,593	6,008	125	4,142	281	965	-		72	47%
Total		24,708	14,909	252	7,279	484	1,680	32		72	
(925) Injuries and damages		451,258									AE-PRI-GTA&G
- Demand	DMD-PRI	238,936	162,565	2,335	57,287	3,695	13,055	-		-	53%
- Customer	CUST-GTA&G	582	-	-	-	-	-	582		-	0%
- Commodity	NRG-PRI	211,740	109,735	2,277	75,655	5,137	17,627	-		1,310	47%
Total		451,258	272,300	4,611	132,942	8,832	30,681	582		1,310	
(935) Maintenance of general plant		403,631									AE-PRI-GTA&G
- Demand	DMD-PRI	213,718	145,408	2,088	51,241	3,305	11,677	-		-	53%
- Customer	CUST-GTA&G	520	-	-	-	-	-	520		-	0%
- Commodity	NRG-PRI	189,392	98,153	2,037	67,670	4,595	15,766	-		1,172	47%
Total		403,631	243,561	4,125	118,911	7,900	27,443	520		1,172	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
(929) Duplicate charges—Credit		-									AE-PRI-GTA&G
- Demand		-	-	-	-	-	-	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity		-	-	-	-	-	-	-		-	47%
Total		-	-	-	-	-	-	-		-	
(928) Regulatory commission expenses		1,424,394									AE-PRI-GTA&G
- Demand	DMD-PRI	754,201	513,136	7,369	180,826	11,663	41,207	-		-	53%
- Customer	CUST-GTA&G	1,837	-	-	-	-	-	1,837		-	0%
- Commodity	NRG-PRI	668,356	346,377	7,187	238,804	16,215	55,638	-		4,135	47%
Total		1,424,394	859,513	14,556	419,630	27,878	96,845	1,837		4,135	
(930.1) Gen Advertising Exp		228,486									AE-PRI-GTA&G
- Demand	DMD-PRI	120,981	82,312	1,182	29,006	1,871	6,610	-		-	53%
- Customer	CUST-GTA&G	295	-	-	-	-	-	295		-	0%
- Commodity	NRG-PRI	107,211	55,562	1,153	38,306	2,601	8,925	-		663	47%
Total		228,486	137,874	2,335	67,313	4,472	15,535	295		663	
(930.2) Misc Gen Exp		715,398									AE-PRI-GTA&G
- Demand	DMD-PRI	378,795	257,721	3,701	90,820	5,858	20,696	-		-	53%
- Customer	CUST-GTA&G	922	-	-	-	-	-	922		-	0%
- Commodity	NRG-PRI	335,680	173,967	3,610	119,938	8,144	27,944	-		2,077	47%
Total		715,398	431,688	7,311	210,758	14,001	48,640	922		2,077	
(931) Rents		633,423									AE-PRI-GTA&G
- Demand	DMD-PRI	335,390	228,190	3,277	80,413	5,186	18,324	-		-	53%
- Customer	CUST-GTA&G	817	-	-	-	-	-	817		-	0%
- Commodity	NRG-PRI	297,216	154,033	3,196	106,195	7,211	24,742	-		1,839	47%
Total		633,423	382,222	6,473	186,608	12,397	43,067	817		1,839	
(932) Institutional Ad - Newspaper		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(933) Transportation expenses		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total A&G Expense		20,037,357									
- Demand		10,609,562	7,218,431	103,664	2,543,737	164,063	579,666	-		-	
- Customer		25,836	-	-	-	-	-	25,836		-	
- Commodity		9,401,959	4,872,588	101,099	3,359,317	228,100	782,681	-		58,175	
Total		20,037,357	12,091,019	204,763	5,903,055	392,163	1,362,347	25,836		58,175	
O&M Adjustment											
Adjustment											
Int on Cust Deposits		517,477									CUS
- Demand		-	-	-	-	-	-	-		-	0%
- Customer	CUST-DEP	517,477	452,261	6,401	58,383	84	269	78		-	100%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		517,477	452,261	6,401	58,383	84	269	78		-	
Annualize Payroll Increase		1,506,137									PAY-CS
- Demand	PAY-CS-D	765,638	369,540	19,818	245,157	6,390	17,033	-		107,701	51%
- Customer	PAY-CS-C	432,341	329,664	4,430	41,423	914	27,972	27,643		-	29%
- Commodity	PAY-CS-E	308,157	167,395	3,406	105,080	6,842	23,308	296		1,799	20%
Total		1,506,137	866,598	27,654	391,659	14,145	68,313	27,940		109,500	
Svngs Pln Match on Payroll Inc		45,184									PAY-CS
- Demand	PAY-CS-D	22,969	11,086	595	7,355	192	511	-		3,231	51%
- Customer	PAY-CS-C	12,970	9,890	133	1,243	27	839	829		-	29%
- Commodity	PAY-CS-E	9,245	5,022	102	3,152	205	699	9		54	20%
Total		45,184	25,998	830	11,750	424	2,049	838		3,285	
Reclass Amortization of Net Loss on Reacquired Debt		55,682									DISTPLT-CS
- Demand	DISTPLT-CS-D	43,105	4,585	488	4,963	46	-	-		33,024	77%
- Customer	DISTPLT-CS-C	12,576	9,600	129	1,206	27	815	791		-	23%
- Commodity	DISTPLT-CS-E	-	-	-	-	-	-	-		-	0%
Total		55,682	14,185	617	6,169	72	815	791		33,024	
BPU & RPA Assessments		92,421									DIST-REV
- Demand	DIST-REV-DMD	24,408	-	-	15,771	1,244	3,069	2,281		1,999	26%
- Customer	DIST-REV-CUST	7,442	5,308	162	1,823	15	60	74		-	8%
- Commodity	DIST-REV-NRG	60,572	44,989	832	12,288	306	789	597		770	66%
Total		92,421	50,297	994	29,882	1,566	3,918	2,951		2,769	
Rate Case Exp		-									AE-ALL
- Demand	DMD-ALL	-	-	-	-	-	-	-		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	-	-	-	-	-	-	-		-	48%
Total		-	-	-	-	-	-	-		-	
Pension Smoothing		4,118,496									PAY-CS
- Demand	PAY-CS-D	2,093,620	1,010,498	54,192	670,375	17,474	46,576	-		294,506	51%
- Customer	PAY-CS-C	1,182,227	901,457	12,113	113,270	2,498	76,489	75,590		-	29%
- Commodity	PAY-CS-E	842,649	457,736	9,314	287,338	18,708	63,735	811		4,920	20%
Total		4,118,496	2,369,691	75,618	1,070,983	38,680	186,801	76,401		299,426	
OPEB Smoothing		1,413,226									PAY-CS
- Demand	PAY-CS-D	718,407	346,743	18,595	230,033	5,996	15,982	-		101,057	51%
- Customer	PAY-CS-C	405,671	309,327	4,156	38,868	857	26,247	25,938		-	29%
- Commodity	PAY-CS-E	289,147	157,068	3,196	98,598	6,420	21,870	278		1,688	20%
Total		1,413,226	813,139	25,948	367,498	13,273	64,099	26,216		102,745	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
Normalize Vegetation Management Expense		-									OHPLT-CS
- Demand	OHPLT-CS-D	-	-	-	-	-	-	-		-	0%
- Customer	OHPLT-CS-C	-	-	-	-	-	-	-		-	0%
- Commodity	OHPLT-CS-E	-	-	-	-	-	-	-		-	0%
Total		-	-	-	-	-	-	-		-	
ServCo Depr @ JCP&L Rates		269,402									AE-ALL
- Demand	DMD-ALL	139,493	88,749	1,275	31,275	2,017	7,127	8,075		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	129,909	61,340	1,273	42,290	2,872	9,853	10,320		732	48%
Total		269,402	150,089	2,547	73,564	4,889	16,980	18,394		732	
SERP/EDCP		1,418,028									PAY-CS
- Demand	PAY-CS-D	720,848	347,922	18,659	230,815	6,016	16,036	-		101,401	51%
- Customer	PAY-CS-C	407,049	310,378	4,171	39,000	860	26,336	26,026		-	29%
- Commodity	PAY-CS-E	290,130	157,602	3,207	98,933	6,441	21,944	279		1,694	20%
Total		1,418,028	815,902	26,036	368,747	13,318	64,317	26,305		103,094	
BGS Administrative Labor included in BGS Deferral		-									AE-ALL
- Demand	DMD-ALL	-	-	-	-	-	-	-		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	-	-	-	-	-	-	-		-	48%
Total		-	-	-	-	-	-	-		-	
Low Income O&M		740,131									AE-ALL
- Demand	DMD-ALL	383,230	243,820	3,501	85,921	5,542	19,580	22,184		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	356,901	168,521	3,497	116,183	7,889	27,069	28,351		2,012	48%
Total		740,131	412,341	6,998	202,104	13,431	46,649	50,535		2,012	
Advertising removal		-									N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
Contract Labor/Fuel Costs		-									N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
Total O&M Adjustment		10,176,183									
- Demand		4,911,718	2,422,942	117,122	1,521,664	44,916	125,914	32,539		642,918	
- Customer		2,977,755	2,327,886	31,695	295,215	5,284	159,027	156,969		-	
- Commodity		2,286,710	1,219,673	24,826	763,862	49,683	169,268	40,941		13,670	
Total		10,176,183	5,970,500	173,643	2,580,741	99,883	454,209	230,449		656,588	
Total O&M Expenses		88,276,542									
- Demand		44,613,702	21,585,332	1,144,775	14,234,200	376,274	1,009,152	32,539		6,227,728	
- Customer		25,396,715	19,422,509	261,398	2,443,189	52,663	1,609,517	1,590,404		-	
- Commodity		18,266,125	9,899,873	201,448	6,212,752	404,452	1,377,898	56,315		106,968	
Total		**88,276,542**	**50,907,714**	**1,607,620**	**22,890,141**	**833,390**	**3,996,568**	**1,679,258**		**6,334,696**	
DEPRECIATION EXPENSE											
Depreciation Expense											
(403-360) Land & Land Rights		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(403-361) Struct & Impmnts		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(403-362) Station Equip		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(403-364) Poles, Towers & Fixt		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(403-365) OH Cond & Dev		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(403-366) UG Conduit		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(403-367) UG Cond & Dev		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
(403-368) Line Transformers		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(403-369) Services		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(403-370) Meters		10,227,000									MTR
- Demand	DMD-MTR	4,550,528	2,069,422	220,462	2,240,016	20,628	-	-		-	44%
- Customer	CUST-MTR	5,676,473	4,333,347	58,228	544,494	12,010	367,687	356,815		-	56%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		10,227,000	6,402,768	278,689	2,784,510	32,638	367,687	356,815		-	
(403-371) Install on Cust Premise		1,173,277									DEM
- Demand	DMD-LTG	1,173,277	-	-	-	-	-	-		1,173,277	100%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		1,173,277	-	-	-	-	-	-		1,173,277	
(403-373) St Lt & Signal Sys		8,028,829									DEM
- Demand	DMD-LTG	8,028,829	-	-	-	-	-	-		8,028,829	100%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		8,028,829	-	-	-	-	-	-		8,028,829	
(403-374) Asset Ret Costs		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(403-389) Land & Land Rights		38									AE-ALL
- Demand	DMD-ALL	20	13	0	4	0	1	1		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	18	9	0	6	0	1	1		0	48%
Total		38	21	0	10	1	2	3		0	
(403-390) Struct & Impmnts -		121,381									AE-ALL
- Demand	DMD-ALL	62,849	39,986	574	14,091	909	3,211	3,638		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	58,531	27,637	573	19,054	1,294	4,439	4,650		330	48%
Total		121,381	67,623	1,148	33,145	2,203	7,650	8,288		330	
(403-391) Office Furn & Equip		599,114									AE-ALL
- Demand	DMD-ALL	310,213	197,365	2,834	69,550	4,486	15,849	17,957		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	288,901	136,412	2,830	94,047	6,386	21,912	22,950		1,629	48%
Total		599,114	333,777	5,665	163,597	10,872	37,761	40,906		1,629	
(403-392) Transportation Equip		139,127									AE-ALL
- Demand	DMD-ALL	72,038	45,833	658	16,151	1,042	3,681	4,170		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	67,089	31,678	657	21,840	1,483	5,088	5,329		378	48%
Total		139,127	77,510	1,315	37,991	2,525	8,769	9,499		378	
(403-393) Stores Equip		1,820									AE-ALL
- Demand	DMD-ALL	942	600	9	211	14	48	55		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	878	414	9	286	19	67	70		5	48%
Total		1,820	1,014	17	497	33	115	124		5	
(403-394) Tools, Shop & Garage Equip		83,569									AE-ALL
- Demand	DMD-ALL	43,271	27,530	395	9,701	626	2,211	2,505		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	40,298	19,028	395	13,118	891	3,056	3,201		227	48%
Total		83,569	46,558	790	22,820	1,516	5,267	5,706		227	
(403-395) Laboratory Equip		1,714									AE-ALL
- Demand	DMD-ALL	888	565	8	199	13	45	51		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	827	390	8	269	18	63	66		5	48%
Total		1,714	955	16	468	31	108	117		5	
(403-396) Power Operated Equip		5,228									AE-ALL
- Demand	DMD-ALL	2,707	1,722	25	607	39	138	157		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	2,521	1,190	25	821	56	191	200		14	48%
Total		5,228	2,913	49	1,428	95	330	357		14	
(403-397) Communication Equip		295,864									AE-ALL
- Demand	DMD-ALL	153,194	97,466	1,400	34,346	2,215	7,827	8,868		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	142,669	67,365	1,398	46,444	3,154	10,821	11,333		804	48%
Total		295,864	164,831	2,797	80,790	5,369	18,648	20,201		804	
(403-398) MISC Equip		(1,548)									AE-ALL
- Demand	DMD-ALL	(802)	(510)	(7)	(180)	(12)	(41)	(46)		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(747)	(353)	(7)	(243)	(17)	(57)	(59)		(4)	48%
Total		(1,548)	(863)	(15)	(423)	(28)	(98)	(106)		(4)	
Total Depreciation Expense		20,675,414									
- Demand		14,397,955	2,479,991	226,358	2,384,699	29,959	32,970	37,355		9,202,106	
- Customer		5,676,473	4,333,347	58,228	544,494	12,010	367,687	356,815		-	
- Commodity		600,986	283,772	5,888	195,641	13,284	45,582	47,741		3,388	
Total		20,675,414	7,097,109	290,474	3,124,834	55,254	446,240	441,911		9,205,494	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	Lighting LTG	Classification Factor
Depreciation Adjustment										
Adjustment										
Annualize Deprec Exp		1,378,574								DPR-TOT-CS
- Demand	DPR-TOT-CS-D	960,012	165,358	15,093	159,005	1,998	2,198	2,491	613,569	70%
- Customer	DPR-TOT-CS-C	378,490	288,934	3,882	36,305	801	24,516	23,791	-	27%
- Commodity	DPR-TOT-CS-E	40,072	18,921	393	13,045	886	3,039	3,183	226	3%
Total		1,378,574	473,214	19,368	208,355	3,684	29,754	29,465	613,795	
Average Net Salvage		387,212								DISTPLT-CS
- Demand	DISTPLT-CS-D	299,757	31,883	3,397	34,511	318	-	-	229,648	77%
- Customer	DISTPLT-CS-C	87,455	66,762	897	8,389	185	5,665	5,497	-	23%
- Commodity	DISTPLT-CS-E	-	-	-	-	-	-	-	-	0%
Total		387,212	98,645	4,294	42,900	503	5,665	5,497	229,648	
Total Depreciation Adjustment		1,765,786								
- Demand		1,259,769	197,241	18,489	193,516	2,315	2,198	2,491	843,217	
- Customer		465,945	355,697	4,780	44,694	986	30,181	29,289	-	
- Commodity		40,072	18,921	393	13,045	886	3,039	3,183	226	
Total		1,765,786	571,859	23,662	251,254	4,187	35,419	34,963	843,443	
Total Depreciation Expense										
- Demand		15,657,724	2,677,232	244,847	2,578,214	32,275	35,169	39,846	10,045,323	
- Customer		6,142,418	4,689,043	63,007	589,188	12,996	397,869	386,104	-	
- Commodity		641,058	302,693	6,280	208,686	14,170	48,621	50,924	3,614	
Total		**22,441,200**	**7,668,968**	**314,135**	**3,376,089**	**59,441**	**481,659**	**476,873**	**10,048,937**	
Amortization, Accretion, Regulatory Debits and Credits										
Amort - Ltd Term Elec Prpty		1,279,397								DISTPLT-CS
- Demand	DISTPLT-CS-D	990,434	105,345	11,223	114,029	1,050	-	-	758,787	77%
- Customer	DISTPLT-CS-C	288,963	220,591	2,964	27,718	611	18,717	18,164	-	23%
- Commodity	DISTPLT-CS-E	-	-	-	-	-	-	-	-	0%
Total		1,279,397	325,936	14,187	141,747	1,661	18,717	18,164	758,787	
Accretion Expense		41,510								AE-ALL
- Demand	DMD-ALL	21,493	13,675	196	4,819	311	1,098	1,244	-	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	20,017	9,451	196	6,516	442	1,518	1,590	113	48%
Total		41,510	23,126	392	11,335	753	2,616	2,834	113	
Regulatory Debits		6,729,898								AE-ALL
- Demand	DMD-ALL	3,484,651	2,217,019	31,839	781,266	50,389	178,035	201,712	-	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	3,245,247	1,532,332	31,794	1,056,439	71,733	246,138	257,794	18,295	48%
Total		6,729,898	3,749,351	63,632	1,837,704	122,122	424,172	459,506	18,295	
Regulatory Credits		2,803								AE-ALL
- Demand	DMD-ALL	1,451	923	13	325	21	74	84	-	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	1,352	638	13	440	30	103	107	8	48%
Total		2,803	1,562	27	765	51	177	191	8	
Total Depreciation and Amortization		30,494,809								
- Demand		20,155,753	5,014,194	288,118	3,478,653	84,046	214,376	242,885	10,804,110	
- Customer		6,431,382	4,909,634	65,971	616,906	13,608	416,586	404,267	-	
- Commodity		3,907,674	1,845,115	38,283	1,272,081	86,375	296,380	310,416	22,029	
Total		**30,494,809**	**11,768,943**	**392,373**	**5,367,640**	**184,029**	**927,341**	**957,568**	**10,826,139**	
TAXES										
Taxes Other than Income										
(408) Payroll Taxes		1,046,433								PAY-CS
- Demand	PAY-CS-D	531,950	256,749	13,769	170,330	4,440	11,834	-	74,828	51%
- Customer	PAY-CS-C	300,382	229,043	3,078	28,780	635	19,434	19,206	-	29%
- Commodity	PAY-CS-E	214,101	116,302	2,366	73,007	4,753	16,194	206	1,250	20%
Total		1,046,433	602,094	19,213	272,117	9,828	47,463	19,412	76,078	
(408) Property Taxes		552,539								RB-CS
- Demand	RB-CS-D	392,512	108,840	6,075	74,093	1,849	4,809	5,065	191,168	71%
- Customer	RB-CS-C	71,928	48,008	606	5,845	274	8,665	8,437	-	13%
- Commodity	RB-CS-E	88,099	42,172	873	28,713	1,939	6,649	6,484	497	16%
Total		552,539	199,021	7,554	108,651	4,062	20,123	19,987	191,665	
Total Taxes Other than Income		1,598,972								
- Demand		924,462	365,589	19,844	244,422	6,289	16,643	5,065	265,997	
- Customer		372,310	277,052	3,684	34,625	909	28,100	27,643	-	
- Commodity		302,200	158,475	3,239	101,720	6,693	22,843	6,690	1,747	
Total Taxes Other than Income		**1,598,972**	**801,115**	**26,767**	**380,767**	**13,890**	**67,586**	**39,399**	**267,743**	
Total Expenses		**120,370,322**								
- Demand		**65,693,917**	**26,965,114**	**1,452,737**	**17,957,276**	**466,609**	**1,240,171**	**280,489**	**17,297,835**	
- Customer		**32,200,406**	**24,609,194**	**331,053**	**3,094,720**	**67,180**	**2,054,203**	**2,022,315**	**-**	
- Commodity		**22,476,000**	**11,903,462**	**242,971**	**7,586,553**	**497,520**	**1,697,121**	**373,420**	**130,744**	
Total		**120,370,322**	**63,477,771**	**2,026,761**	**28,638,549**	**1,031,309**	**4,991,495**	**2,676,225**	**17,428,578**	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
REVENUE REQUIREMENT CALCULATION											
Total Rate Base											
- Demand		232,658,676	64,514,128	3,601,024	43,917,900	1,096,034	2,850,565	3,002,434		113,313,529	
- Customer		42,634,643	28,456,480	359,247	3,464,521	162,373	5,136,353	5,001,130		-	
- Commodity		52,220,176	24,997,345	517,263	17,019,447	1,149,537	3,940,934	3,843,371		294,307	
Total		327,513,495	117,967,953	4,477,534	64,401,868	2,407,943	11,927,852	11,846,935		113,607,836	
Required Net Income											
- Demand		17,682,059	4,903,074	273,678	3,337,760	83,299	216,643	228,185		8,611,828	
- Customer		3,240,233	2,162,692	27,303	263,304	12,340	390,363	380,086		-	
- Commodity		3,968,733	1,899,798	39,312	1,293,478	87,365	299,511	292,096		22,367	
Total		24,891,026	8,965,564	340,293	4,894,542	183,004	906,517	900,367		8,634,196	
Interest Synchronization											
- Demand		5,116,471	1,418,751	79,191	965,813	24,103	62,688	66,027		2,491,914	
- Customer		937,592	625,796	7,900	76,189	3,571	112,955	109,981		-	
- Commodity		1,148,391	549,725	11,375	374,280	25,280	86,666	84,521		6,472	
Total		7,202,454	2,594,271	98,467	1,416,282	52,954	262,309	260,530		2,498,386	
Net Income Before Income Taxes											
- Demand		12,565,588	3,484,323	194,487	2,371,948	59,195	153,955	162,157		6,119,914	
- Customer		2,302,641	1,536,897	19,402	187,114	8,770	277,408	270,104		-	
- Commodity		2,820,343	1,350,074	27,937	919,198	62,085	212,845	207,575		15,895	
Total		17,688,572	6,371,293	241,826	3,478,260	130,050	644,208	639,837		6,135,809	
Taxable Income											
- Demand		17,478,910	4,846,742	270,534	3,299,413	82,342	214,154	225,563		8,512,887	
- Customer		3,203,006	2,137,845	26,989	260,278	12,199	385,878	375,719		-	
- Commodity		3,923,136	1,877,971	38,860	1,278,617	86,361	296,070	288,740		22,110	
Total		24,605,052	8,862,559	336,383	4,838,308	180,901	896,102	890,023		8,534,997	
NJ State Corporate Business Tax											
- Demand		1,573,102	436,207	24,348	296,947	7,411	19,274	20,301		766,160	
- Customer		288,271	192,406	2,429	23,425	1,098	34,729	33,815		-	
- Commodity		353,082	169,017	3,497	115,076	7,772	26,646	25,987		1,990	
Total		2,214,455	797,630	30,274	435,448	16,281	80,649	80,102		768,150	
Federal Taxable Income											
- Demand		15,905,808	4,410,535	246,185	3,002,466	74,931	194,880	205,263		7,746,727	
- Customer		2,914,735	1,945,439	24,560	236,853	11,101	351,149	341,904		-	
- Commodity		3,570,054	1,708,954	35,363	1,163,542	78,589	269,424	262,754		20,120	
Total		22,390,597	8,064,928	306,108	4,402,861	164,620	815,453	809,921		7,766,847	
Federal Income Tax											
- Demand		3,340,220	926,212	51,699	630,518	15,735	40,925	43,105		1,626,813	
- Customer		612,094	408,542	5,158	49,739	2,331	73,741	71,800		-	
- Commodity		749,711	358,880	7,426	244,344	16,504	56,579	55,178		4,225	
Total		4,702,025	1,693,635	64,283	924,601	34,570	171,245	170,083		1,631,038	
NJ Federal & State Income Tax		6,916,480									
- Demand		4,913,321	1,362,419	76,047	927,465	23,146	60,199	63,406		2,392,972	
- Customer		900,365	600,948	7,587	73,164	3,429	108,470	105,615		-	
- Commodity		1,102,794	527,898	10,924	359,419	24,276	83,225	81,165		6,215	
Total		6,916,480	2,491,265	94,557	1,360,048	50,851	251,894	250,185		2,399,188	
Tax Reform Amortization		(1,014,645)									RB-CS
- Demand	RB-CS-D	(720,782)	(199,866)	(11,156)	(136,059)	(3,396)	(8,831)	(9,302)		(351,048)	71%
- Customer	RB-CS-C	(132,083)	(88,159)	(1,113)	(10,733)	(503)	(15,913)	(15,494)		-	13%
- Commodity	RB-CS-E	(161,779)	(77,442)	(1,602)	(52,727)	(3,561)	(12,209)	(11,907)		(912)	16%
Total		(1,014,645)	(365,468)	(13,872)	(199,519)	(7,460)	(36,953)	(36,702)		(351,960)	
Investment Tax Credit		(14,797)									RB-CS
- Demand	RB-CS-D	(10,512)	(2,915)	(163)	(1,984)	(50)	(129)	(136)		(5,120)	71%
- Customer	RB-CS-C	(1,926)	(1,286)	(16)	(157)	(7)	(232)	(226)		-	13%
- Commodity	RB-CS-E	(2,359)	(1,129)	(23)	(769)	(52)	(178)	(174)		(13)	16%
Total		(14,797)	(5,330)	(202)	(2,910)	(109)	(539)	(535)		(5,133)	
Federal & State Income Taxes											
- Demand		4,182,028	1,159,638	64,728	789,422	19,701	51,239	53,969		2,036,805	
- Customer		766,356	511,504	6,457	62,275	2,919	92,326	89,895		-	
- Commodity		938,655	449,326	9,298	305,924	20,663	70,838	69,084		5,290	
Total		5,887,038	2,120,468	80,483	1,157,620	43,283	214,403	212,948		2,042,095	
Revenue Requirement											
- Demand		**87,558,004**	**33,027,826**	**1,791,143**	**22,084,458**	**569,609**	**1,508,052**	**562,643**		**27,946,468**	
- Customer		**36,206,994**	**27,283,391**	**364,813**	**3,420,298**	**82,439**	**2,536,892**	**2,492,296**		**-**	
- Commodity		**27,383,388**	**14,252,587**	**291,581**	**9,185,955**	**605,548**	**2,067,470**	**734,601**		**158,401**	
Total		**151,148,386**	**74,563,803**	**2,447,537**	**34,690,711**	**1,257,595**	**6,112,414**	**3,789,540**		**28,104,869**	

Jersey Central Power & Light - First Energy Corp. Summary of Allocation Factors	Primary	Secondary	Customer Service
UTILITY PLANT			
Intangible Plant			
(301) Organizational Costs			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(302) Franchises & Consents			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(303) Misc. Intangible Plant			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
Distribution Plant			
(360) Land and Land Rights			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(361) Structures and Improvements			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(362) Station Equipment			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(364) Poles, Towers & Fixtures			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(365) Overhead Conductors & Devices			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(366) Underground Conduit			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	

Jersey Central Power & Light - First Energy Corp. Summary of Allocation Factors	Primary	Secondary	Customer Service
(367) Underground Conductors & Device			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(368) Line Transformers			
- Demand		DMD-SEC	
- Customer			
- Commodity		NRG-SEC	
(369) Services			
- Demand		DMD-SEC	
- Customer		CUST-SVCS	
- Commodity			
(370) Meters			
- Demand			DMD-MTR
- Customer			CUST-MTR
- Commodity			
(371) Installation on Customers' Premises			
- Demand			DMD-LTG
- Customer			
- Commodity			
(373) Street Lighting & Signal Systems			
- Demand			DMD-LTG
- Customer			
- Commodity			
(374) Asset Retirement Costs			
- Demand	DMD-PRI		
- Customer			
- Commodity	NRG-PRI		
(375) Charging Stations			
- Demand			
- Customer			
- Commodity			
General Plant			
(389) Land and Land Rights			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(390) Structures and Improvements			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL

Jersey Central Power & Light - First Energy Corp. Summary of Allocation Factors	Primary	Secondary	Customer Service
(391) Office Furniture & Equipment			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(392) Transportation Equipment			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(393) Stores Equipment			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(394) Tools, Shop & Garage Equipment			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(395) Laboratory Equipment			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(396) Power Operated Equipment			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(397) Communication Equipment			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(398) Misc. Equipment			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(399) Other Tangible Property			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(SRVCO-PIS) Service Company PIS			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL

Jersey Central Power & Light - First Energy Corp. Summary of Allocation Factors	Primary	Secondary	Customer Service
Additions to Utility Plant			
Construction Work in Progress			
- Demand			
- Customer			
- Commodity			
ACCUMULATED DEPRECIATION			
Accumulated Depreciation			
(108-303) Misc Intangible Plant			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(108-360) Land & Land Rights			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(108-361) Struct & Impmnts			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(108-362) Station Equip			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(108-364) Poles, Towers & Fixt			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(108-365) OH Cond & Dev			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(108-366) UG Conduit			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(108-367) UG Cond & Dev			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	

Jersey Central Power & Light - First Energy Corp. Summary of Allocation Factors	Primary	Secondary	Customer Service
(108-368) Line Transformers			
- Demand		DMD-SEC	
- Customer			
- Commodity		NRG-SEC	
(108-369) Services			
- Demand		DMD-SEC	
- Customer		CUST-SVCS	
- Commodity			
(108-370) Meters			
- Demand			DMD-MTR
- Customer			CUST-MTR
- Commodity			
(108-371) Install on Cust Premise			
- Demand			DMD-LTG
- Customer			
- Commodity			
(108-373) St Lt & Signal Sys			
- Demand			DMD-LTG
- Customer			
- Commodity			
(108-374) Asset Ret Costs			
- Demand	DMD-PRI		
- Customer			
- Commodity	NRG-PRI		
(108-389) Land & Land Rights			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(108-390) Struct & Impmnts -			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(108-391) Office Furn & Equip			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(108-392) Transportation Equip			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL

Jersey Central Power & Light - First Energy Corp. Summary of Allocation Factors	Primary	Secondary	Customer Service
(108-393) Stores Equip			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(108-394) Tools, Shop & Garage Equip			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(108-395) Laboratory Equip			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(108-396) Power Operated Equip			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(108-397) Communication Equip			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(108-398) MISC Equip			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(108-399) Other Tangible Property			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
Service Company PIS			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
OTHER RATE BASE ITEMS			
Other Rate Base Items			
Materials and Supplies			
- Demand	DISTPLT-PRI-D	DISTPLT-SEC-D	DISTPLT-CS-D
- Customer	DISTPLT-PRI-C	DISTPLT-SEC-C	DISTPLT-CS-C
- Commodity	DISTPLT-PRI-E	DISTPLT-SEC-E	DISTPLT-CS-E

Jersey Central Power & Light - First Energy Corp. Summary of Allocation Factors	Primary	Secondary	Customer Service
Cash Working Capital			
- Demand	CWC-PRI-D	CWC-SEC-D	CWC-CS-D
- Customer	CWC-PRI-C	CWC-SEC-C	CWC-CS-C
- Commodity	CWC-PRI-E	CWC-SEC-E	CWC-CS-E
ADIT			
- Demand	DISTPLT-PRI-D	DISTPLT-SEC-D	DISTPLT-CS-D
- Customer	DISTPLT-PRI-C	DISTPLT-SEC-C	DISTPLT-CS-C
- Commodity	DISTPLT-PRI-E	DISTPLT-SEC-E	DISTPLT-CS-E
Net /Loss on Reacq Debt			
- Demand	DISTPLT-PRI-D	DISTPLT-SEC-D	DISTPLT-CS-D
- Customer	DISTPLT-PRI-C	DISTPLT-SEC-C	DISTPLT-CS-C
- Commodity	DISTPLT-PRI-E	DISTPLT-SEC-E	DISTPLT-CS-E
DTA for AMT			
- Demand	DISTPLT-PRI-D	DISTPLT-SEC-D	DISTPLT-CS-D
- Customer	DISTPLT-PRI-C	DISTPLT-SEC-C	DISTPLT-CS-C
- Commodity	DISTPLT-PRI-E	DISTPLT-SEC-E	DISTPLT-CS-E
Net Operating Reserves			
- Demand	PAY-PRI-D	PAY-SEC-D	PAY-CS-D
- Customer	PAY-PRI-C	PAY-SEC-C	PAY-CS-C
- Commodity	PAY-PRI-E	PAY-SEC-E	PAY-CS-E
NOL			
- Demand	DISTPLT-PRI-D	DISTPLT-SEC-D	DISTPLT-CS-D
- Customer	DISTPLT-PRI-C	DISTPLT-SEC-C	DISTPLT-CS-C
- Commodity	DISTPLT-PRI-E	DISTPLT-SEC-E	DISTPLT-CS-E
CTA			
- Demand	TOTPLT-PRI-D	TOTPLT-SEC-D	TOTPLT-CS-D
- Customer	TOTPLT-PRI-C	TOTPLT-SEC-C	TOTPLT-CS-C
- Commodity	TOTPLT-PRI-E	TOTPLT-SEC-E	TOTPLT-CS-E
Regulatory Asset A&G Capitalization			
- Demand	DMD-PRI	DMD-PRI	DMD-PRI
- Customer	CUST-GTA&G	CUST-GTA&G	CUST-GTA&G
- Commodity	NRG-PRI	NRG-PRI	NRG-PRI
Customer Deposits			
- Demand			
- Customer			CUST-DEP
- Commodity			
Customer Advances			
- Demand	DISTPLT-PRI-D	DISTPLT-SEC-D	DISTPLT-CS-D
- Customer	DISTPLT-PRI-C	DISTPLT-SEC-C	DISTPLT-CS-C
- Commodity	DISTPLT-PRI-E	DISTPLT-SEC-E	DISTPLT-CS-E

Jersey Central Power & Light - First Energy Corp. Summary of Allocation Factors	Primary	Secondary	Customer Service
Customer Refunds			
- Demand	DISTPLT-PRI-D	DISTPLT-SEC-D	DISTPLT-CS-D
- Customer	DISTPLT-PRI-C	DISTPLT-SEC-C	DISTPLT-CS-C
- Commodity	DISTPLT-PRI-E	DISTPLT-SEC-E	DISTPLT-CS-E
OPERATIONS & MAINTENANCE EXPENSES			
Distribution Expenses			
Operations Expenses			
(580) Operation Supervision & Engineering			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(581) Load Dispatching			
- Demand	DMD-PRI		
- Customer			
- Commodity	NRG-PRI		
(582) Station Expenses			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(583) Overhead line expenses			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(584) Underground line expenses			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(585) Street lighting and signal system expenses			
- Demand			
- Customer			
- Commodity			
(586) Meter expenses			
- Demand			DMD-MTR
- Customer			CUST-MTR
- Commodity			
(587) Customer installations expenses			
- Demand			
- Customer			
- Commodity			

Jersey Central Power & Light - First Energy Corp. Summary of Allocation Factors	Primary	Secondary	Customer Service
(588) Miscellaneous distribution expenses			
- Demand	DISTPLT-PRI-D	DISTPLT-SEC-D	DISTPLT-CS-D
- Customer	DISTPLT-PRI-C	DISTPLT-SEC-C	DISTPLT-CS-C
- Commodity	DISTPLT-PRI-E	DISTPLT-SEC-E	DISTPLT-CS-E
(589) Rents			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
Total Dist. Operations Expenses			
- Demand			
- Customer			
- Commodity			
Maintenance Expense			
(590) Maintenance Supervision and Engineering			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(591) Maintenance of Structures			
- Demand	DMD-PRI		
- Customer			
- Commodity	NRG-PRI		
(592) Maintenance of Station Equipment			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(593) Maintenance of Overhead Lines			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(594) Maintenance of underground lines			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(595) Maintenance of line transformers			
- Demand		DMD-SEC	
- Customer			
- Commodity			
(596) Maintenance of street lighting and signal systems			
- Demand			DMD-LTG
- Customer			
- Commodity			

Jersey Central Power & Light - First Energy Corp. Summary of Allocation Factors	Primary	Secondary	Customer Service
(597) Maintenance of meters			
- Demand			DMD-MTR
- Customer			CUST-MTR
- Commodity			
(598) Maintenance of miscellaneous distribution plant			
- Demand	DISTPLT-PRI-D	DISTPLT-SEC-D	DISTPLT-CS-D
- Customer	DISTPLT-PRI-C	DISTPLT-SEC-C	DISTPLT-CS-C
- Commodity	DISTPLT-PRI-E	DISTPLT-SEC-E	DISTPLT-CS-E
Total Dist. Maintenance Expenses			
- Demand			
- Customer			
- Commodity			
Customer Account Expense			
(901) Supervision			
- Demand			
- Customer			
- Commodity			ALL901
(902) Meter reading expenses			
- Demand			DMD-MTR
- Customer			CUST-MTR
- Commodity			
(903) Customer records and collection expenses			
- Demand			DMD-MTR
- Customer			CUST-MTR
- Commodity			
(904) Uncollectible accounts			
- Demand			
- Customer			
- Commodity			NRG-ALL
(905) Miscellaneous customer accounts expenses			
- Demand			
- Customer			
- Commodity			ALL905
Customer Service Expenses			
(907) Customer Service Supervision			
- Demand			DMD-PRI
- Customer			
- Commodity			NRG-PRI
(908) Customer Assistance			
- Demand			DMD-PRI
- Customer			
- Commodity			NRG-PRI

Jersey Central Power & Light - First Energy Corp. Summary of Allocation Factors	Primary	Secondary	Customer Service
(909) Informational and instructional advertising			
- Demand			DMD-PRI
- Customer			
- Commodity			NRG-PRI
(910) Miscellaneous customer service and informational			
- Demand			DMD-PRI
- Customer			
- Commodity			NRG-PRI
Sales Expenses			
(911) Sales Exp			
- Demand			DMD-PRI
- Customer			
- Commodity			NRG-PRI
Administrative & General Expense			
Labor Related			
(920) Administrative and general salaries			
- Demand	DMD-PRI	DMD-PRI	DMD-PRI
- Customer	CUST-GTA&G	CUST-GTA&G	CUST-GTA&G
- Commodity	NRG-PRI	NRG-PRI	NRG-PRI
(921) Office supplies and expenses			
- Demand	DMD-PRI	DMD-PRI	DMD-PRI
- Customer	CUST-GTA&G	CUST-GTA&G	CUST-GTA&G
- Commodity	NRG-PRI	NRG-PRI	NRG-PRI
(922) Administrative expenses transferred—Credit			
- Demand	DMD-PRI	DMD-PRI	DMD-PRI
- Customer	CUST-GTA&G	CUST-GTA&G	CUST-GTA&G
- Commodity	NRG-PRI	NRG-PRI	NRG-PRI
(923) Outside services employed			
- Demand	DMD-PRI	DMD-PRI	DMD-PRI
- Customer	CUST-GTA&G	CUST-GTA&G	CUST-GTA&G
- Commodity	NRG-PRI	NRG-PRI	NRG-PRI
(926) Employee pensions and benefits			
- Demand	DMD-PRI	DMD-PRI	DMD-PRI
- Customer	CUST-GTA&G	CUST-GTA&G	CUST-GTA&G
- Commodity	NRG-PRI	NRG-PRI	NRG-PRI
(426) Pension / OPEB Non-Service Cost			
- Demand			
- Customer			
- Commodity			

Jersey Central Power & Light - First Energy Corp. Summary of Allocation Factors	Primary	Secondary	Customer Service
(924) Property insurance			
- Demand	DMD-PRI	DMD-PRI	DMD-PRI
- Customer	CUST-GTA&G	CUST-GTA&G	CUST-GTA&G
- Commodity	NRG-PRI	NRG-PRI	NRG-PRI
(925) Injuries and damages			
- Demand	DMD-PRI	DMD-PRI	DMD-PRI
- Customer	CUST-GTA&G	CUST-GTA&G	CUST-GTA&G
- Commodity	NRG-PRI	NRG-PRI	NRG-PRI
(935) Maintenance of general plant			
- Demand	DMD-PRI	DMD-PRI	DMD-PRI
- Customer	CUST-GTA&G	CUST-GTA&G	CUST-GTA&G
- Commodity	NRG-PRI	NRG-PRI	NRG-PRI
(929) Duplicate charges—Credit			
- Demand			
- Customer			
- Commodity			
(928) Regulatory commission expenses			
- Demand	DMD-PRI	DMD-PRI	DMD-PRI
- Customer	CUST-GTA&G	CUST-GTA&G	CUST-GTA&G
- Commodity	NRG-PRI	NRG-PRI	NRG-PRI
(930.1) Gen Advertising Exp			
- Demand	DMD-PRI	DMD-PRI	DMD-PRI
- Customer	CUST-GTA&G	CUST-GTA&G	CUST-GTA&G
- Commodity	NRG-PRI	NRG-PRI	NRG-PRI
(930.2) Misc Gen Exp			
- Demand	DMD-PRI	DMD-PRI	DMD-PRI
- Customer	CUST-GTA&G	CUST-GTA&G	CUST-GTA&G
- Commodity	NRG-PRI	NRG-PRI	NRG-PRI
(931) Rents			
- Demand	DMD-PRI	DMD-PRI	DMD-PRI
- Customer	CUST-GTA&G	CUST-GTA&G	CUST-GTA&G
- Commodity	NRG-PRI	NRG-PRI	NRG-PRI
(932) Institutional Ad - Newspaper			
- Demand			
- Customer			
- Commodity			
(933) Transportation expenses			
- Demand			
- Customer			
- Commodity			

Jersey Central Power & Light - First Energy Corp. Summary of Allocation Factors	Primary	Secondary	Customer Service
DEPRECIATION EXPENSE			
Depreciation Expense			
(403-360) Land & Land Rights			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(403-361) Struct & Impmnts			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(403-362) Station Equip			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(403-364) Poles, Towers & Fixt			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(403-365) OH Cond & Dev			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(403-366) UG Conduit			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(403-367) UG Cond & Dev			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(403-368) Line Transformers			
- Demand		DMD-SEC	
- Customer			
- Commodity		NRG-SEC	
(403-369) Services			
- Demand		DMD-SEC	
- Customer		CUST-SVCS	
- Commodity			

Jersey Central Power & Light - First Energy Corp. Summary of Allocation Factors	Primary	Secondary	Customer Service
(403-370) Meters			
- Demand			DMD-MTR
- Customer			CUST-MTR
- Commodity			
(403-371) Install on Cust Premise			
- Demand			DMD-LTG
- Customer			
- Commodity			
(403-373) St Lt & Signal Sys			
- Demand			DMD-LTG
- Customer			
- Commodity			
(403-374) Asset Ret Costs			
- Demand	DMD-PRI		
- Customer			
- Commodity	NRG-PRI		
(403-389) Land & Land Rights			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(403-390) Struct & Impmnts -			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(403-391) Office Furn & Equip			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(403-392) Transportation Equip			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(403-393) Stores Equip			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(403-394) Tools, Shop & Garage Equip			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL

Jersey Central Power & Light - First Energy Corp. Summary of Allocation Factors	Primary	Secondary	Customer Service
(403-395) Laboratory Equip			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(403-396) Power Operated Equip			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(403-397) Communication Equip			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(403-398) MISC Equip			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
Amort - Ltd Term Elec Prpty			
- Demand	DISTPLT-PRI-D	DISTPLT-SEC-D	DISTPLT-CS-D
- Customer	DISTPLT-PRI-C	DISTPLT-SEC-C	DISTPLT-CS-C
- Commodity	DISTPLT-PRI-E	DISTPLT-SEC-E	DISTPLT-CS-E
Accretion Expense			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
Regulatory Debits			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
Regulatory Credits			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL

Jersey Central Power & Light - First Energy Corp. Summary of Allocation Factors	Primary	Secondary	Customer Service
TAXES			
Taxes Other than Income			
(408) Payroll Taxes			
- Demand	PAY-PRI-D	PAY-SEC-D	PAY-CS-D
- Customer	PAY-PRI-C	PAY-SEC-C	PAY-CS-C
- Commodity	PAY-PRI-E	PAY-SEC-E	PAY-CS-E
(408) Property Taxes			
- Demand	RB-PRI-D	RB-SEC-D	RB-CS-D
- Customer	RB-PRI-C	RB-SEC-C	RB-CS-C
- Commodity	RB-PRI-E	RB-SEC-E	RB-CS-E
Interest Synchronization			
- Demand			
- Customer			
- Commodity			
ADJUSTMENTS			
O&M Adjustments			
Int on Cust Deposits			
- Demand			
- Customer	CUST-DEP	CUST-DEP	CUST-DEP
- Commodity			
Annualize Payroll Increase			
- Demand	PAY-PRI-D	PAY-SEC-D	PAY-CS-D
- Customer	PAY-PRI-C	PAY-SEC-C	PAY-CS-C
- Commodity	PAY-PRI-E	PAY-SEC-E	PAY-CS-E
Svngs Pln Match on Payroll Inc			
- Demand	PAY-PRI-D	PAY-SEC-D	PAY-CS-D
- Customer	PAY-PRI-C	PAY-SEC-C	PAY-CS-C
- Commodity	PAY-PRI-E	PAY-SEC-E	PAY-CS-E
Reclass Amortization of Net Loss on Reacquired Debt			
- Demand	DISTPLT-PRI-D	DISTPLT-SEC-D	DISTPLT-CS-D
- Customer	DISTPLT-PRI-C	DISTPLT-SEC-C	DISTPLT-CS-C
- Commodity	DISTPLT-PRI-E	DISTPLT-SEC-E	DISTPLT-CS-E
BPU & RPA Assessments			
- Demand	DIST-REV-DMD	DIST-REV-DMD	DIST-REV-DMD
- Customer	DIST-REV-CUST	DIST-REV-CUST	DIST-REV-CUST
- Commodity	DIST-REV-NRG	DIST-REV-NRG	DIST-REV-NRG
Rate Case Exp			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL

Jersey Central Power & Light - First Energy Corp. Summary of Allocation Factors	Primary	Secondary	Customer Service
Pension Smoothing			
- Demand	PAY-PRI-D	PAY-SEC-D	PAY-CS-D
- Customer	PAY-PRI-C	PAY-SEC-C	PAY-CS-C
- Commodity	PAY-PRI-E	PAY-SEC-E	PAY-CS-E
OPEB Smoothing			
- Demand	PAY-PRI-D	PAY-SEC-D	PAY-CS-D
- Customer	PAY-PRI-C	PAY-SEC-C	PAY-CS-C
- Commodity	PAY-PRI-E	PAY-SEC-E	PAY-CS-E
Normalize Vegetation Management Expense			
- Demand	OHPLT-PRI-D	OHPLT-SEC-D	OHPLT-CS-D
- Customer	OHPLT-PRI-C	OHPLT-SEC-C	OHPLT-CS-C
- Commodity	OHPLT-PRI-E	OHPLT-SEC-E	OHPLT-CS-E
ServCo Depr @ JCP&L Rates			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
SERP/EDCP			
- Demand	PAY-PRI-D	PAY-SEC-D	PAY-CS-D
- Customer	PAY-PRI-C	PAY-SEC-C	PAY-CS-C
- Commodity	PAY-PRI-E	PAY-SEC-E	PAY-CS-E
BGS Administrative Labor included in BGS Deferral			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
Low Income O&M			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
Advertising removal			
- Demand	DMD-PRI		
- Customer	CUST-GTA&G		
- Commodity	NRG-PRI		
Contract Labor/Fuel Costs			
- Demand	DMD-PRI		
- Customer	CUST-GTA&G		
- Commodity	NRG-PRI		
Rate Base			
AMI			
- Demand			DMD-MTR
- Customer			CUST-MTR
- Commodity			

Jersey Central Power & Light - First Energy Corp. Summary of Allocation Factors	Primary	Secondary	Customer Service
Delayed Recognition Pension & OPEB			
- Demand	PAY-PRI-D	PAY-SEC-D	PAY-CS-D
- Customer	PAY-PRI-C	PAY-SEC-C	PAY-CS-C
- Commodity	PAY-PRI-E	PAY-SEC-E	PAY-CS-E
Depreciation			
Annualize Deprec Exp			
- Demand	DPR-TOT-PRI-D	DPR-TOT-SEC-D	DPR-TOT-CS-D
- Customer	DPR-TOT-PRI-C	DPR-TOT-SEC-C	DPR-TOT-CS-C
- Commodity	DPR-TOT-PRI-E	DPR-TOT-SEC-E	DPR-TOT-CS-E
Average Net Salvage			
- Demand	DISTPLT-PRI-D	DISTPLT-SEC-D	DISTPLT-CS-D
- Customer	DISTPLT-PRI-C	DISTPLT-SEC-C	DISTPLT-CS-C
- Commodity	DISTPLT-PRI-E	DISTPLT-SEC-E	DISTPLT-CS-E
Income			
Amortization of Fed Income Tax Credit			
- Demand	RB-PRI-D	RB-SEC-D	RB-CS-D
- Customer	RB-PRI-C	RB-SEC-C	RB-CS-C
- Commodity	RB-PRI-E	RB-SEC-E	RB-CS-E
Tax Reform Amortization			
- Demand	RB-PRI-D	RB-SEC-D	RB-CS-D
- Customer	RB-PRI-C	RB-SEC-C	RB-CS-C
- Commodity	RB-PRI-E	RB-SEC-E	RB-CS-E
Investment Tax Credit			
- Demand	RB-PRI-D	RB-SEC-D	RB-CS-D
- Customer	RB-PRI-C	RB-SEC-C	RB-CS-C
- Commodity	RB-PRI-E	RB-SEC-E	RB-CS-E

Jersey Central Power & Light - First Energy Corp. Summary of Classification Factors	Primary	Secondary	Customer Service
UTILITY PLANT			
Intangible Plant			
(301) Organizational Costs	AE-ALL	AE-ALL	AE-ALL
(302) Franchises & Consents	AE-ALL	AE-ALL	AE-ALL
(303) Misc. Intangible Plant	AE-ALL	AE-ALL	AE-ALL
Distribution Plant			
(360) Land and Land Rights	AE-PRI	AE-SEC	
(361) Structures and Improvements	AE-PRI	AE-SEC	
(362) Station Equipment	AE-PRI	AE-SEC	
(364) Poles, Towers & Fixtures	AE-PRI	AE-SEC	
(365) Overhead Conductors & Devices	AE-PRI	AE-SEC	
(366) Underground Conduit	AE-PRI	AE-SEC	
(367) Underground Conductors & Device	AE-PRI	AE-SEC	
(368) Line Transformers		AE-SEC	
(369) Services		SRVC	
(370) Meters			MTR
(371) Installation on Customers' Premises			DEM
(373) Street Lighting & Signal Systems			DEM
(374) Asset Retirement Costs	AE-PRI		
(375) Charging Stations			
General Plant			
(389) Land and Land Rights	AE-ALL	AE-ALL	AE-ALL
(390) Structures and Improvements	AE-ALL	AE-ALL	AE-ALL
(391) Office Furniture & Equipment	AE-ALL	AE-ALL	AE-ALL
(392) Transportation Equipment	AE-ALL	AE-ALL	AE-ALL
(393) Stores Equipment	AE-ALL	AE-ALL	AE-ALL
(394) Tools, Shop & Garage Equipment	AE-ALL	AE-ALL	AE-ALL
(395) Laboratory Equipment	AE-ALL	AE-ALL	AE-ALL
(396) Power Operated Equipment	AE-ALL	AE-ALL	AE-ALL
(397) Communication Equipment	AE-ALL	AE-ALL	AE-ALL
(398) Misc. Equipment	AE-ALL	AE-ALL	AE-ALL
(399) Other Tangible Property	AE-ALL	AE-ALL	AE-ALL
(SRVCO-PIS) Service Company PIS	AE-ALL	AE-ALL	AE-ALL
Additions to Utility Plant			
Construction Work in Progress			
ACCUMULATED DEPRECIATION			
Accumulated Depreciation			
(108-303) Misc Intangible Plant	AE-ALL	AE-ALL	AE-ALL
(108-360) Land & Land Rights	AE-PRI	AE-SEC	
(108-361) Struct & Impmnts	AE-PRI	AE-SEC	
(108-362) Station Equip	AE-PRI	AE-SEC	
(108-364) Poles, Towers & Fixt	AE-PRI	AE-SEC	
(108-365) OH Cond & Dev	AE-PRI	AE-SEC	
(108-366) UG Conduit	AE-PRI	AE-SEC	
(108-367) UG Cond & Dev	AE-PRI	AE-SEC	
(108-368) Line Transformers		AE-SEC	
(108-369) Services		SRVC	
(108-370) Meters			MTR
(108-371) Install on Cust Premise			DEM
(108-373) St Lt & Signal Sys			DEM
(108-374) Asset Ret Costs	AE-PRI		
(108-389) Land & Land Rights	AE-ALL	AE-ALL	AE-ALL
(108-390) Struct & Impmnts -	AE-ALL	AE-ALL	AE-ALL

Jersey Central Power & Light - First Energy Corp. Summary of Classification Factors	Primary	Secondary	Customer Service
(108-391) Office Furn & Equip	AE-ALL	AE-ALL	AE-ALL
(108-392) Transportation Equip	AE-ALL	AE-ALL	AE-ALL
(108-393) Stores Equip	AE-ALL	AE-ALL	AE-ALL
(108-394) Tools, Shop & Garage Equip	AE-ALL	AE-ALL	AE-ALL
(108-395) Laboratory Equip	AE-ALL	AE-ALL	AE-ALL
(108-396) Power Operated Equip	AE-ALL	AE-ALL	AE-ALL
(108-397) Communication Equip	AE-ALL	AE-ALL	AE-ALL
(108-398) MISC Equip	AE-ALL	AE-ALL	AE-ALL
(108-399) Other Tangible Property	AE-ALL	AE-ALL	AE-ALL
Service Company PIS	AE-ALL	AE-ALL	AE-ALL
OTHER RATE BASE ITEMS			
Other Rate Base Items			
Materials and Supplies	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
Cash Working Capital	CWC-PRI	CWC-SEC	CWC-CS
ADIT	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
Net /Loss on Reacq Debt	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
DTA for AMT	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
Net Operating Reserves	PAY-PRI	PAY-SEC	PAY-CS
NOL	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
CTA	TOTPLT-PRI	TOTPLT-SEC	TOTPLT-CS
Regulatory Asset A&G Capitalization	AE-PRI-GTA&G	AE-PRI-GTA&G	AE-PRI-GTA&G
Customer Deposits	CUS	CUS	CUS
Customer Advances	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
Customer Refunds	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
OPERATIONS & MAINTENANCE EXPENSES			
Distribution Expenses			
Operations Expenses			
(580) Operation Supervision & Engineering	AE-PRI	AE-SEC	
(581) Load Dispatching	AE-PRI		
(582) Station Expenses	AE-PRI	AE-SEC	
(583) Overhead line expenses	AE-PRI	AE-SEC	
(584) Underground line expenses	AE-PRI	AE-SEC	
(585) Street lighting and signal system expenses			
(586) Meter expenses			MTR
(587) Customer installations expenses			
(588) Miscellaneous distribution expenses	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
(589) Rents	AE-PRI	AE-SEC	
Maintenance Expense			
(590) Maintenance Supervision and Engineering	AE-PRI	AE-SEC	
(591) Maintenance of Structures	AE-PRI	AE-SEC	
(592) Maintenance of Station Equipment	AE-PRI	AE-SEC	
(593) Maintenance of Overhead Lines	AE-PRI	AE-SEC	
(594) Maintenance of underground lines	AE-PRI	AE-SEC	
(595) Maintenance of line transformers		DEM	
(596) Maintenance of street lighting and signal systems			DEM
(597) Maintenance of meters			MTR
(598) Maintenance of miscellaneous distribution p	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
Customer Account Expense			
(901) Supervision			COM
(902) Meter reading expenses			MTR
(903) Customer records and collection expenses			MTR
(904) Uncollectible accounts			COM
(905) Miscellaneous customer accounts expenses			COM

Jersey Central Power & Light - First Energy Corp. Summary of Classification Factors	Primary	Secondary	Customer Service
Customer Service Expenses			
(907) Customer Service Supervision			AE-PRI
(908) Customer Assistance			AE-PRI
(909) Informational and instructional advertising			AE-PRI
(910) Miscellaneous customer service and informational			AE-PRI
Sales Expenses			
(911) Sales Exp			AE-PRI
Administrative & General Expense			
(920) Administrative and general salaries	AE-PRI-GTA&G	AE-PRI-GTA&G	AE-PRI-GTA&G
(921) Office supplies and expenses	AE-PRI-GTA&G	AE-PRI-GTA&G	AE-PRI-GTA&G
(922) Administrative expenses transferred—Credit	AE-PRI-GTA&G	AE-PRI-GTA&G	AE-PRI-GTA&G
(923) Outside services employed	AE-PRI-GTA&G	AE-PRI-GTA&G	AE-PRI-GTA&G
(926) Employee pensions and benefits	AE-PRI-GTA&G	AE-PRI-GTA&G	AE-PRI-GTA&G
(426) Pension / OPEB Non-Service Cost	AE-PRI-GTA&G	AE-PRI-GTA&G	AE-PRI-GTA&G
(924) Property insurance	AE-PRI-GTA&G	AE-PRI-GTA&G	AE-PRI-GTA&G
(925) Injuries and damages	AE-PRI-GTA&G	AE-PRI-GTA&G	AE-PRI-GTA&G
(935) Maintenance of general plant	AE-PRI-GTA&G	AE-PRI-GTA&G	AE-PRI-GTA&G
(929) Duplicate charges—Credit	AE-PRI-GTA&G	AE-PRI-GTA&G	AE-PRI-GTA&G
(928) Regulatory commission expenses	AE-PRI-GTA&G	AE-PRI-GTA&G	AE-PRI-GTA&G
(930.1) Gen Advertising Exp	AE-PRI-GTA&G	AE-PRI-GTA&G	AE-PRI-GTA&G
(930.2) Misc Gen Exp	AE-PRI-GTA&G	AE-PRI-GTA&G	AE-PRI-GTA&G
(931) Rents	AE-PRI-GTA&G	AE-PRI-GTA&G	AE-PRI-GTA&G
(932) Institutional Ad - Newspaper			
(933) Transportation expenses			
DEPRECIATION EXPENSE			
Depreciation Expense			
(403-360) Land & Land Rights	AE-PRI	AE-SEC	
(403-361) Struct & Impmnts	AE-PRI	AE-SEC	
(403-362) Station Equip	AE-PRI	AE-SEC	
(403-364) Poles, Towers & Fixt	AE-PRI	AE-SEC	
(403-365) OH Cond & Dev	AE-PRI	AE-SEC	
(403-366) UG Conduit	AE-PRI	AE-SEC	
(403-367) UG Cond & Dev	AE-PRI	AE-SEC	
(403-368) Line Transformers		AE-SEC	
(403-369) Services		SRVC	
(403-370) Meters			MTR
(403-371) Install on Cust Premise			DEM
(403-373) St Lt & Signal Sys			DEM
(403-374) Asset Ret Costs	AE-PRI		
(403-389) Land & Land Rights	AE-ALL	AE-ALL	AE-ALL
(403-390) Struct & Impmnts -	AE-ALL	AE-ALL	AE-ALL
(403-391) Office Furn & Equip	AE-ALL	AE-ALL	AE-ALL
(403-392) Transportation Equip	AE-ALL	AE-ALL	AE-ALL
(403-393) Stores Equip	AE-ALL	AE-ALL	AE-ALL
(403-394) Tools, Shop & Garage Equip	AE-ALL	AE-ALL	AE-ALL
(403-395) Laboratory Equip	AE-ALL	AE-ALL	AE-ALL
(403-396) Power Operated Equip	AE-ALL	AE-ALL	AE-ALL
(403-397) Communication Equip	AE-ALL	AE-ALL	AE-ALL
(403-398) MISC Equip	AE-ALL	AE-ALL	AE-ALL
Amortization, Accretion, Regulatory Debits and Credits			
Amort - Ltd Term Elec Prpty	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
Accretion Expense	AE-ALL	AE-ALL	AE-ALL
Regulatory Debits	AE-ALL	AE-ALL	AE-ALL
Regulatory Credits	AE-ALL	AE-ALL	AE-ALL

Jersey Central Power & Light - First Energy Corp. Summary of Classification Factors	Primary	Secondary	Customer Service
TAXES			
Taxes Other than Income			
(408) Payroll Taxes	PAY-PRI	PAY-SEC	PAY-CS
(408) Property Taxes	RB-PRI	RB-SEC	RB-CS
Income Taxes			
Federal & State Income Taxes			
Income Tax Derivation			
Tax Reform Amortization	RB-PRI	RB-SEC	RB-CS
Investment Tax Credit	RB-PRI	RB-SEC	RB-CS
ADJUSTMENTS			
O&M			
Int on Cust Deposits	CUS	CUS	CUS
Annualize Payroll Increase	PAY-PRI	PAY-SEC	PAY-CS
Svngs Pln Match on Payroll Inc	PAY-PRI	PAY-SEC	PAY-CS
Reclass Amortization of Net Loss on Reacquired D	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
BPU & RPA Assessments	DIST-REV	DIST-REV	DIST-REV
Rate Case Exp	AE-ALL	AE-ALL	AE-ALL
Pension Smoothing	PAY-PRI	PAY-SEC	PAY-CS
OPEB Smoothing	PAY-PRI	PAY-SEC	PAY-CS
Normalize Vegetation Management Expense	OHPLT-PRI	OHPLT-SEC	OHPLT-CS
ServCo Depr @ JCP&L Rates	AE-ALL	AE-ALL	AE-ALL
SERP/EDCP	PAY-PRI	PAY-SEC	PAY-CS
BGS Administrative Labor included in BGS Deferral	AE-ALL	AE-ALL	AE-ALL
Low Income O&M	AE-ALL	AE-ALL	AE-ALL
Advertising removal	AE-PRI-GTA&G		
Contract Labor/Fuel Costs	AE-PRI-GTA&G		
-	AE-PRI-GTA&G		
Rate Base			
AMI			MTR
Delayed Recognition Pension & OPEB	PAY-PRI	PAY-SEC	PAY-CS
Depreciation			
Annualize Deprec Exp	DPR-TOT-PRI	DPR-TOT-SEC	DPR-TOT-CS
Average Net Salvage	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS

Jersey Central Power & Light - First Energy Corp. Summary of Allocators	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
External Allocators									
External Allocators									
ALL451	100.00%	79.94%	0.56%	18.39%	0.01%	0.06%	1.04%		0.00%
LATEPAY	100.00%	0.05%	0.00%	80.41%	3.43%	9.69%	2.69%		3.72%
ALL901	100.00%	79.26%	1.41%	18.52%	0.23%	0.21%	0.12%		0.25%
ALL905	100.00%	79.26%	1.41%	18.52%	0.23%	0.21%	0.12%		0.25%
CUST-ALL	100.00%	87.18%	1.23%	11.25%	0.02%	0.05%	0.01%		0.25%
CUST-PRI	100.00%	87.19%	1.23%	11.26%	0.02%	0.05%	0.00%		0.25%
CUST-SEC	100.00%	87.24%	1.23%	11.26%	0.02%	0.00%	0.00%		0.25%
CUST-DEP	100.00%	87.40%	1.24%	11.28%	0.02%	0.05%	0.01%		0.00%
CUST-GTA&G	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%		0.00%
CUST-LTG	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		100.00%
CUST-MTR	100.00%	76.34%	1.03%	9.59%	0.21%	6.48%	6.29%		0.00%
CUST-SVCS	100.00%	87.46%	1.24%	11.29%	0.02%	0.00%	0.00%		0.00%
DMD-MTR	100.00%	45.48%	4.84%	49.23%	0.45%	0.00%	0.00%		0.00%
DMD-ALL	100.00%	63.62%	0.91%	22.42%	1.45%	5.11%	5.79%		0.00%
DMD-PRI	100.00%	68.04%	0.98%	23.98%	1.55%	5.46%	0.00%		0.00%
DMD-SEC	100.00%	71.97%	1.03%	25.36%	1.64%	0.00%	0.00%		0.00%
DMD-LTG	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		100.00%
DIST-REV-DMD	100.00%	0.00%	0.00%	64.62%	5.10%	12.57%	9.34%		8.19%
DIST-REV-CUST	100.00%	71.32%	2.18%	24.49%	0.21%	0.80%	0.99%		0.00%
DIST-REV-NRG	100.00%	74.27%	1.37%	20.29%	0.51%	1.30%	0.99%		1.27%
NRG-ALL	100.00%	47.22%	0.98%	32.55%	2.21%	7.58%	7.94%		0.56%
NRG-PRI	100.00%	51.83%	1.08%	35.73%	2.43%	8.32%	0.00%		0.62%
NRG-SEC	100.00%	56.53%	1.17%	38.97%	2.65%	0.00%	0.00%		0.67%
REV-ALL	100.00%	54.42%	1.08%	32.33%	1.69%	4.24%	3.19%		3.00%

Jersey Central Power & Light - First Energy Corp. Summary of Allocators	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
Internal Allocators									
DISTPLT-PRI-D	100.00%	68.04%	0.98%	23.98%	1.55%	5.46%	0.00%		0.00%
DISTPLT-PRI-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		0.00%
DISTPLT-PRI-E	100.00%	51.83%	1.08%	35.73%	2.43%	8.32%	0.00%		0.62%
DISTPLT-SEC-D	100.00%	71.97%	1.03%	25.36%	1.64%	0.00%	0.00%		0.00%
DISTPLT-SEC-C	100.00%	87.46%	1.24%	11.29%	0.02%	0.00%	0.00%		0.00%
DISTPLT-SEC-E	100.00%	56.53%	1.17%	38.97%	2.65%	0.00%	0.00%		0.67%
DISTPLT-CS-D	100.00%	10.64%	1.13%	11.51%	0.11%	0.00%	0.00%		76.61%
DISTPLT-CS-C	100.00%	76.34%	1.03%	9.59%	0.21%	6.48%	6.29%		0.00%
DISTPLT-CS-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		0.00%
RB-PRI-D	100.00%	67.63%	0.97%	23.83%	1.54%	5.43%	0.53%		0.00%
RB-PRI-C	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%		0.00%
RB-PRI-E	100.00%	51.39%	1.07%	35.43%	2.41%	8.25%	0.76%		0.61%
RB-SEC-D	100.00%	71.53%	1.03%	25.21%	1.63%	0.31%	0.26%		0.00%
RB-SEC-C	100.00%	87.43%	1.24%	11.29%	0.02%	0.00%	0.03%		0.00%
RB-SEC-E	100.00%	55.92%	1.16%	38.56%	2.62%	0.58%	0.44%		0.67%
RB-CS-D	100.00%	27.73%	1.55%	18.88%	0.47%	1.23%	1.29%		48.70%
RB-CS-C	100.00%	66.74%	0.84%	8.13%	0.38%	12.05%	11.73%		0.00%
RB-CS-E	100.00%	47.87%	0.99%	32.59%	2.20%	7.55%	7.36%		0.56%
PAY-PRI-D	100.00%	68.04%	0.98%	23.98%	1.55%	5.46%	0.00%		0.00%
PAY-PRI-C	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%		0.00%
PAY-PRI-E	100.00%	51.83%	1.08%	35.73%	2.43%	8.32%	0.00%		0.62%
PAY-SEC-D	100.00%	70.85%	1.02%	24.97%	1.61%	1.56%	0.00%		0.00%
PAY-SEC-C	100.00%	84.00%	1.19%	10.84%	0.02%	0.00%	3.96%		0.00%
PAY-SEC-E	100.00%	55.10%	1.14%	37.99%	2.58%	2.53%	0.00%		0.66%
PAY-CS-D	100.00%	48.27%	2.59%	32.02%	0.83%	2.22%	0.00%		14.07%
PAY-CS-C	100.00%	76.25%	1.02%	9.58%	0.21%	6.47%	6.39%		0.00%
PAY-CS-E	100.00%	54.32%	1.11%	34.10%	2.22%	7.56%	0.10%		0.58%
TOTPLT-PRI-D	100.00%	67.61%	0.97%	23.83%	1.54%	5.43%	0.55%		0.00%
TOTPLT-PRI-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		0.00%
TOTPLT-PRI-E	100.00%	51.36%	1.07%	35.41%	2.40%	8.25%	0.80%		0.61%
TOTPLT-SEC-D	100.00%	71.38%	1.03%	25.15%	1.62%	0.36%	0.41%		0.00%
TOTPLT-SEC-C	100.00%	87.46%	1.24%	11.29%	0.02%	0.00%	0.00%		0.00%
TOTPLT-SEC-E	100.00%	55.70%	1.16%	38.40%	2.61%	0.68%	0.71%		0.66%

Jersey Central Power & Light - First Energy Corp. Summary of Allocators	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
TOTPLT-CS-D	100.00%	18.59%	1.10%	13.15%	0.31%	0.77%	0.87%		65.11%
TOTPLT-CS-C	100.00%	76.34%	1.03%	9.59%	0.21%	6.48%	6.29%		0.00%
TOTPLT-CS-E	100.00%	47.22%	0.98%	32.55%	2.21%	7.58%	7.94%		0.56%
DPR-TOT-PRI-D	100.00%	67.61%	0.97%	23.82%	1.54%	5.43%	0.56%		0.00%
DPR-TOT-PRI-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		0.00%
DPR-TOT-PRI-E	100.00%	51.36%	1.07%	35.41%	2.40%	8.25%	0.81%		0.61%
DPR-TOT-SEC-D	100.00%	71.13%	1.02%	25.06%	1.62%	0.52%	0.58%		0.00%
DPR-TOT-SEC-C	100.00%	87.46%	1.24%	11.29%	0.02%	0.00%	0.00%		0.00%
DPR-TOT-SEC-E	100.00%	55.39%	1.15%	38.18%	2.59%	0.93%	0.98%		0.66%
DPR-TOT-CS-D	100.00%	17.22%	1.57%	16.56%	0.21%	0.23%	0.26%		63.91%
DPR-TOT-CS-C	100.00%	76.34%	1.03%	9.59%	0.21%	6.48%	6.29%		0.00%
DPR-TOT-CS-E	100.00%	47.22%	0.98%	32.55%	2.21%	7.58%	7.94%		0.56%
OHPLT-PRI-D	100.00%	68.04%	0.98%	23.98%	1.55%	5.46%	0.00%		0.00%
OHPLT-PRI-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		0.00%
OHPLT-PRI-E	100.00%	51.83%	1.08%	35.73%	2.43%	8.32%	0.00%		0.62%
OHPLT-SEC-D	100.00%	71.97%	1.03%	25.36%	1.64%	0.00%	0.00%		0.00%
OHPLT-SEC-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		0.00%
OHPLT-SEC-E	100.00%	56.53%	1.17%	38.97%	2.65%	0.00%	0.00%		0.67%
OHPLT-CS-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		0.00%
OHPLT-CS-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		0.00%
OHPLT-CS-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		0.00%
CWC-PRI-D	100.00%	68.04%	0.98%	23.98%	1.55%	5.46%	0.00%		0.00%
CWC-PRI-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		0.00%
CWC-PRI-E	100.00%	51.83%	1.08%	35.73%	2.43%	8.32%	0.00%		0.62%
CWC-SEC-D	100.00%	71.97%	1.03%	25.36%	1.64%	0.00%	0.00%		0.00%
CWC-SEC-C	100.00%	87.46%	1.24%	11.29%	0.02%	0.00%	0.00%		0.00%
CWC-SEC-E	100.00%	56.53%	1.17%	38.97%	2.65%	0.00%	0.00%		0.67%
CWC-CS-D	100.00%	41.06%	3.18%	34.95%	0.58%	1.04%	0.00%		19.20%
CWC-CS-C	100.00%	76.34%	1.03%	9.59%	0.21%	6.48%	6.29%		0.00%
CWC-CS-E	100.00%	57.89%	1.15%	31.77%	1.93%	6.48%	0.23%		0.53%

Jersey Central Power & Light - First Energy Corp.
Summary of Classifiers

Classifier Description	Classifier Code	Total	- Demand	- Customer	- Commodity
External Classifiers					
Customer Factor	CUS	100.00%	0.00%	100.00%	0.00%
Demand Factor	DEM	100.00%	100.00%	0.00%	0.00%
Commodity Factor	COM	100.00%	0.00%	0.00%	100.00%
Avg/Excess All	AE-ALL	100.00%	51.78%	0.00%	48.22%
Avg/Excess Primary	AE-PRI	100.00%	53.02%	0.00%	46.98%
Avg/Exc Secondary	AE-SEC	100.00%	54.44%	0.00%	45.56%
Avg/Exc for GT A&G	AE-PRI-GTA&G	100.00%	52.95%	0.13%	46.92%
Distribution Revs	DIST-REV	100.00%	26.41%	8.05%	65.54%
Meters (Complied)	MTR	100.00%	44.50%	55.50%	0.00%
Services (Complied)	SRVC	100.00%	50.00%	50.00%	0.00%
Meters (Complied)		100.00%	44.50%	55.50%	0.00%
Services (Complied)		100.00%	50.00%	50.00%	0.00%
Meters (Alternative Proposal)		100.00%	15.33%	84.67%	0.00%
Services (Alternative Proposal)		100.00%	0.15%	99.85%	0.00%
Internal Classifiers					
Distribution Plant Primary	DISTPLT-PRI	100.00%	53.02%	0.00%	46.98%
Distribution Plant Secondary	DISTPLT-SEC	100.00%	53.76%	7.70%	38.54%
Distribution Plant Customer	DISTPLT-CS	100.00%	77.41%	22.59%	0.00%
Rate Base Primary	RB-PRI	100.00%	52.90%	0.00%	47.10%
Rate Base Secondary	RB-SEC	100.00%	53.76%	5.97%	40.27%
Rate Base Customer	RB-CS	100.00%	71.04%	13.02%	15.94%
Payroll Primary	PAY-PRI	100.00%	53.00%	0.04%	46.97%
Payroll Secondary	PAY-SEC	100.00%	53.99%	0.95%	45.06%
Payroll Customer	PAY-CS	100.00%	50.83%	28.71%	20.46%
Total Plant Primary	TOTPLT-PRI	100.00%	52.90%	0.00%	47.10%
Total Plant Secondary	TOTPLT-SEC	100.00%	53.61%	7.14%	39.25%
Total Plant Customer	TOTPLT-CS	100.00%	72.06%	17.87%	10.08%
Total Depreciation Primary	DPR-TOT-PRI	100.00%	52.89%	0.00%	47.11%
Total Depreciation Secondary	DPR-TOT-SEC	100.00%	53.70%	5.23%	41.07%
Total Depreciation Customer	DPR-TOT-CS	100.00%	69.64%	27.46%	2.91%
OH Plant Primary	OHPLT-PRI	100.00%	53.02%	0.00%	46.98%
OH Plant Secondary	OHPLT-SEC	100.00%	54.44%	0.00%	45.56%
OH Plant Customer	OHPLT-CS	0.00%	0.00%	0.00%	0.00%
Cash Working Capital Primary	CWC-PRI	100.00%	53.02%	0.00%	46.98%
Cash Working Capital Secondary	CWC-SEC	100.00%	54.42%	1.29%	44.29%
Cash Working Capital Customer	CWC-CS	100.00%	50.10%	38.57%	11.33%

Jersey Central Power & Light - First Energy Corp. Functional Factors	Code	Total	Primary	Secondary	Customer Service
EXTERNAL FUNCTIONAL FACTORS					
Total System	CUSTSERVICE	100.0%	0.0%	0.0%	100.0%
Account 360 Land and Land Rights	ACC360	100.0%	50.0%	50.0%	0.0%
Account 361 Structures and Improvements	ACC361	100.0%	50.0%	50.0%	0.0%
Account 362 Station Equipment	ACC362	100.0%	50.0%	50.0%	0.0%
Account 364 Poles, Towers & Fixtures	ACC364	100.0%	50.0%	50.0%	0.0%
Account 365 Overhead Conductors & Devices	ACC365	100.0%	50.0%	50.0%	0.0%
Account 366 Underground Conduit	ACC366	100.0%	90.0%	10.0%	0.0%
Account 367 Underground Conductors & Device	ACC367	100.0%	50.0%	50.0%	0.0%
580,590-591 Segmentation	S3-DISTO&M	100.0%	41.0%	59.0%	0.0%
Primary Distribution Only	PRIMARY	100.0%	100.0%	0.0%	0.0%
Secondary Distribution Only	SECONDARY	100.0%	0.0%	100.0%	0.0%
INTERNAL FUNCTIONAL FACTORS					
Total Distribution Plant Factor	DISTPLT	100.0%	33.7%	57.3%	9.0%
Total Utility Plant Factor	TOTPLT	100.0%	33.8%	55.9%	10.3%
Total General Plant Factor	GENPLT	100.0%	35.2%	36.0%	28.8%
Rate Base	RB	100.0%	35.1%	54.0%	11.0%
Dist. Exp excl. 587, 588, 598 Factor	DISTEXP	100.0%	45.3%	45.2%	9.5%
Total Operating Expenses excl. A&G Factor	OPEXP	100.0%	35.2%	35.2%	29.6%
Total Depreciation	TOTDEPR	100.0%	32.8%	52.8%	14.4%
Payroll Factor	PAYROLL	100.0%	35.2%	36.0%	28.8%
Payroll Factor (excl. A&G Expenses)	PAYROLLxAG	100.0%	35.2%	35.2%	29.6%
Overhead Plant (364, 365) Factor	OHPLT	100.0%	50.0%	50.0%	0.0%
INTERNAL FUNCTIONAL FACTORS DERIVATION					
Total Overhead Plant (364, 365)		2,064,639,186	1,032,319,593	1,032,319,593	-
Overhead Plant (364, 365) Factor	OHPLT	100.0%	50.0%	50.0%	0.0%
Total Distribution Plant		5,484,712,711	1,848,954,704	3,143,000,214	492,757,793
Total Distribution Plant Factor	DISTPLT	100.0%	33.7%	57.3%	9.0%
Total General Plant		255,260,286	89,806,497	91,908,263	73,545,526
Total General Plant Factor	GENPLT	100.0%	35.2%	36.0%	28.8%
Total Utility Plant		6,062,034,052	2,049,386,718	3,389,710,401	622,936,932
Total Utility Plant Factor	TOTPLT	100.0%	33.8%	55.9%	10.3%
Rate Base		2,987,495,271	1,047,606,020	1,612,375,756	327,513,495
Rate Base Factor	RB	100.0%	35.1%	54.0%	11.0%
Dist. Exp excl. 587, 588, 598		127,345,869	57,654,585	57,605,739	12,085,545
Dist. Exp excl. 587, 588, 598 Factor	DISTEXP	100.0%	45.3%	45.2%	9.5%
Total Operating Expenses excl. A&G		196,457,805	69,226,727	69,168,077	58,063,002
Total Operating Expenses excl. A&G Factor	OPEXP	100.0%	35.2%	35.2%	29.6%

Jersey Central Power & Light - First Energy Corp. COSS Summary Alternative	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
Current Delivery Service Rates									
Rate base	$ 2,987,495,271	$ 1,780,213,130	$ 29,223,805	$ 892,108,172	$ 49,527,326	$ 81,221,085	$ 23,489,892		$ 129,649,572
Net operating income	$ 94,086,848	$ 27,430,821	$ 1,329,255	$ 45,542,130	$ 2,167,779	$ 7,038,931	$ 10,338,054		$ 459,010
Rate of return	**3.15%**	**1.54%**	**4.55%**	**5.11%**	**4.38%**	**8.67%**	**44.01%**		**0.35%**
Unitized Rate of Return	**1.00**	**0.49**	**1.44**	**1.62**	**1.39**	**2.75**	**13.97**		**0.11**
Relative rate of return	100%	49%	144%	162%	139%	275%	1397%		11%
Distribution Revenues	$ 642,676,612	$ 349,755,697	$ 6,912,701	$ 207,791,273	$ 10,889,186	$ 27,242,693	$ 20,523,970		$ 19,253,942
Other Operating Revenues	$ 12,445,306	$ 6,167,765	$ 89,288	$ 4,961,917	$ 238,373	$ 727,039	$ 103,174		$ 157,405
Total Operating Revenues	$ 655,121,918	$ 355,923,462	$ 7,001,989	$ 212,753,190	$ 11,127,559	$ 27,969,732	$ 20,627,144		$ 19,411,347
Test Period Usage (MWh)	20,178,644	9,422,567	195,504	6,496,218	441,097	1,594,495	1,708,916		112,498
Revenue per MWh	$ 32.47	$ 37.77	$ 35.82	$ 32.75	$ 25.23	$ 17.54	$ 12.07		$ 172.55
Revenues at Equalized Rates of Return									
Rate of return	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%		7.60%
Return requirement	$ 227,049,640	$ 135,296,198	$ 2,221,009	$ 67,800,221	$ 3,764,077	$ 6,172,802	$ 1,785,232		$ 9,853,367
Revenue required (Total)	$ 840,075,031	$ 505,965,716	$ 8,242,431	$ 243,714,507	$ 13,348,031	$ 26,764,934	$ 8,730,049		$ 32,479,031
Revenue required (Base)	$ 827,629,725	$ 499,797,952	$ 8,153,144	$ 238,752,590	$ 13,109,658	$ 26,037,895	$ 8,626,875		$ 32,321,626
Revenue deficiency / (surplus)	$ 184,953,113	$ 150,042,255	$ 1,240,443	$ 30,961,318	$ 2,220,472	$ (1,204,798)	$ (11,897,096)		$ 13,067,684
Percent increase required	28.2%	42.2%	17.7%	14.6%	20.0%	-4.3%	-57.7%		67.3%
Test Period Usage (MWh)	20,178,644	9,422,567	195,504	6,496,218	441,097	1,594,495	1,708,916		112,498
Revenue Required per MWh	$ 41.02	$ 53.04	$ 41.70	$ 36.75	$ 29.72	$ 16.33	$ 5.05		$ 287.31
Revenue deficiency / (surplus) per MWh	$ 9.17	$ 15.92	$ 6.34	$ 4.77	$ 5.03	$ (0.76)	$ (6.96)		$ 116.16
Base Revenue Requirement at EROR									
Demand	398,372,982	239,271,810	3,356,275	109,617,706	5,051,512	8,258,515	2,357,192		30,159,079
Customer	106,780,525	89,883,194	1,256,517	11,529,754	73,858	1,897,090	1,995,555		124,697
Energy	322,476,218	170,642,948	3,540,352	117,605,130	7,984,289	15,882,290	4,274,128		2,037,850
Total Base Revenue Requirement	**827,629,725**	**499,797,952**	**8,153,144**	**238,752,590**	**13,109,658**	**26,037,895**	**8,626,875**		**32,321,626**

Rate Class	Class ROR	Overall ROR
RS	1.54%	3.15%
RT	4.55%	3.15%
GS	5.11%	3.15%
GST	4.38%	3.15%
GP	8.67%	3.15%
GT	44.01%	3.15%
[redacted]		
LTG	0.35%	3.15%

Jersey Central Power & Light - First Energy Corp. COSS Summary Alternative	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
Current Rate of Return	3.15%	1.54%	4.55%	5.11%	4.38%	8.67%	44.01%		0.35%
Proposed Rate of Return	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%		7.60%
EROR Revenues	$ 840,075,031	$ 505,965,716	$ 8,242,431	$ 243,714,507	$ 13,348,031	$ 26,764,934	$ 8,730,049		$ 32,479,031
Current Revenues	655,121,918	355,923,462	7,001,989	212,753,190	11,127,559	27,969,732	20,627,144		19,411,347
Difference	$ 184,953,113	$ 150,042,255	$ 1,240,443	$ 30,961,318	$ 2,220,472	$ (1,204,798)	$ (11,897,096)		$ 13,067,684
% Difference	28.23%	42.16%	17.72%	14.55%	19.95%	-4.31%	-57.68%		67.32%
Derivation of Delivery Revenues									
Current Total Revenues	$ 655,121,918	355,923,462	7,001,989	212,753,190	11,127,559	27,969,732	20,627,144		19,411,347
Other Revenues	$ 12,445,306	6,167,765	89,288	4,961,917	238,373	727,039	103,174		157,405
Current Delivery Revenues	$ 642,676,612	$ 349,755,697	$ 6,912,701	$ 207,791,273	$ 10,889,186	$ 27,242,693	$ 20,523,970		$ 19,253,942
Total Revenues at EROR	$ 840,075,031	505,965,716	8,242,431	243,714,507	13,348,031	26,764,934	8,730,049		32,479,031
Other Revenues	12,445,306	6,167,765	89,288	4,961,917	238,373	727,039	103,174		157,405
Delivery Revenues at EROR	$ 827,629,725	$ 499,797,952	$ 8,153,144	$ 238,752,590	$ 13,109,658	$ 26,037,895	$ 8,626,875		$ 32,321,626
Metrics									
Total Revenues at EROR	827,629,725	499,797,952	8,153,144	238,752,590	13,109,658	26,037,895	8,626,875		32,321,626
Test Period Usage (MWh)	20,178,644	9,422,567	195,504	6,496,218	441,097	1,594,495	1,708,916		112,498
Test Period Customers	1,153,297	1,005,454	14,230	129,795	188	599	172		2,857
Revenue requirement per kWh		$ 0.053	$ 0.042	$ 0.037	$ 0.030	$ 0.016	$ 0.005		$ 0.287
Revenue requirement per Customer		$ 497	$ 573	$ 1,839	$ 69,814	$ 43,461	$ 50,048		$ 11,315

Jersey Central Power & Light - First Energy Corp. Revenue Requirements by Cost Classification (At EROR)	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
Demand									
Rate Base	1,511,873,505	904,729,591	12,671,470	420,675,060	19,297,201	25,814,803	5,982,640		121,963,581
Required Return on Rate Base	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%		7.60%
Required Net Income	$ 114,902,386	$ 68,759,449	$ 963,032	$ 31,971,305	$ 1,466,587	$ 1,961,925	$ 454,681		$ 9,269,232
Total Operating Expenses	139,783,369	86,002,630	1,188,149	40,023,425	1,847,732	3,527,102	114,443		7,067,920
Depreciation & Amortization	120,591,256	69,599,004	984,722	32,427,953	1,483,275	2,640,694	1,768,583		11,468,515
Total Other Taxes	4,272,218	2,590,826	36,063	1,203,173	55,288	84,293	10,489		290,790
Total Expenses	$ 264,646,842	$ 158,192,460	$ 2,208,934	$ 73,654,551	$ 3,386,294	$ 6,252,088	$ 1,893,516		$ 18,827,226
Interest Expense	33,248,094	19,896,198	278,662	9,251,200	424,371	567,702	131,566		2,682,140
Income Taxes	31,927,976	19,106,218	267,598	8,883,880	407,521	545,161	126,342		2,575,646
Income Tax Amortization	(4,752,127)	(2,843,750)	(39,829)	(1,322,268)	(60,655)	(81,141)	(18,805)		(383,356)
Revenue Requirement (Demand)	$ 406,725,077	$ 243,214,376	$ 3,399,735	$ 113,187,468	$ 5,199,748	$ 8,678,033	$ 2,455,734		$ 30,288,747
Less: Other Revenues (Demand)	$ 8,352,095	$ 3,942,566	$ 43,460	$ 3,569,762	$ 148,236	$ 419,518	$ 98,542		$ 129,668
Base Revenue Requirement (Demand)	**$ 398,372,982**	**$ 239,271,810**	**$ 3,356,275**	**$ 109,617,706**	**$ 5,051,512**	**$ 8,258,515**	**$ 2,357,192**		**$ 30,159,079**
Customer									
Rate Base	283,270,613	235,325,314	3,270,043	30,087,631	262,498	7,163,868	7,042,301		43,041
Required Return on Rate Base	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%		7.60%
Required Net Income	$ 21,528,567	$ 17,884,724	$ 248,523	$ 2,286,660	$ 19,950	$ 544,454	$ 535,215		$ 3,271
Total Operating Expenses	59,274,482	50,620,540	712,637	6,522,984	26,160	569,875	697,341		119,140
Depreciation & Amortization	19,717,933	16,153,879	223,265	2,059,566	22,375	635,456	616,665		-
Total Other Taxes	1,219,140	1,030,731	14,431	132,302	761	18,947	20,258		1,512
Total Expenses	$ 80,211,555	$ 67,805,150	$ 950,332	$ 8,714,852	$ 49,296	$ 1,224,278	$ 1,334,265		$ 120,653
Interest Expense	6,229,495	5,175,114	71,913	661,667	5,773	157,543	154,869		947
Income Taxes	5,982,152	4,969,636	69,057	635,395	5,543	151,288	148,720		909
Income Tax Amortization	(890,377)	(739,676)	(10,278)	(94,572)	(825)	(22,518)	(22,135)		(135)
Revenue Requirement (Customer)	$ 106,831,896	$ 89,919,834	$ 1,257,635	$ 11,542,335	$ 73,964	$ 1,897,502	$ 1,996,065		$ 124,697
Less: Other Revenues (Customer)	$ 51,371	$ 36,640	$ 1,118	$ 12,581	$ 106	$ 412	$ 510		$ -
Base Revenue Requirement (Customer)	**$ 106,780,525**	**$ 89,883,194**	**$ 1,256,517**	**$ 11,529,754**	**$ 73,858**	**$ 1,897,090**	**$ 1,995,555**		**$ 124,697**

Jersey Central Power & Light - First Energy Corp. Revenue Requirements by Cost Classification (At EROR)	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
Energy									
Rate Base	1,192,351,152	640,158,225	13,282,293	441,345,482	29,967,626	48,242,415	10,464,951		7,642,950
Required Return on Rate Base	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%		7.60%
Required Net Income	$ 90,618,688	$ 48,652,025	$ 1,009,454	$ 33,542,257	$ 2,277,540	$ 3,666,424	$ 795,336		$ 580,864
Total Operating Expenses	115,382,722	61,511,408	1,275,342	42,237,081	2,863,108	6,553,706	184,249		736,518
Depreciation & Amortization	95,657,954	49,325,186	1,023,421	34,006,355	2,309,052	4,944,503	3,092,029		588,901
Total Other Taxes	3,426,244	1,836,076	38,096	1,265,849	85,952	157,612	18,529		21,921
Total Expenses	$ 214,466,920	$ 112,672,670	$ 2,336,860	$ 77,509,285	$ 5,258,112	$ 11,655,820	$ 3,294,807		$ 1,347,340
Interest Expense	26,221,376	14,077,924	292,095	9,705,770	659,028	1,060,914	230,138		168,079
Income Taxes	25,180,254	13,518,959	280,497	9,320,401	632,861	1,018,791	221,000		161,405
Income Tax Amortization	(3,747,803)	(2,012,148)	(41,749)	(1,387,239)	(94,194)	(151,636)	(32,893)		(24,023)
Revenue Requirement (Energy)	$ 326,518,058	$ 172,831,506	$ 3,585,062	$ 118,984,704	$ 8,074,319	$ 16,189,399	$ 4,278,250		$ 2,065,586
Less: Other Revenues (Energy)	$ 4,041,839	$ 2,188,558	$ 44,710	$ 1,379,574	$ 90,030	$ 307,109	$ 4,122		$ 27,737
Base Revenue Requirement (Energy)	**$ 322,476,218**	**$ 170,642,948**	**$ 3,540,352**	**$ 117,605,130**	**$ 7,984,289**	**$ 15,882,290**	**$ 4,274,128**		**$ 2,037,850**

Jersey Central Power & Light - First Energy Corp. Income Statement Current Rates	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
Operating Revenues	**655,121,918**	**355,923,462**	**7,001,989**	**212,753,190**	**11,127,559**	**27,969,732**	**20,627,144**		**19,411,347**
Operating Expenses									
O&M Expenses	314,440,573	198,134,578	3,176,128	88,783,489	4,737,000	10,650,683	996,033		7,923,579
Depreciation & Amortization	235,967,143	135,078,068	2,231,409	68,493,875	3,814,702	8,220,653	5,477,278		12,057,416
Taxes Other than Income	8,917,602	5,457,634	88,589	2,601,324	142,001	260,852	49,276		314,224
Total Operating Expenses	559,325,317	338,670,280	5,496,126	159,878,688	8,693,703	19,132,187	6,522,587		20,295,219
Income Before Tax	95,796,600	17,253,182	1,505,863	52,874,502	2,433,856	8,837,545	14,104,557		(883,872)
Interest Expense	65,698,964	39,149,236	642,670	19,618,636	1,089,171	1,786,159	516,574		2,851,165
Taxable Income	30,097,636	(21,896,054)	863,193	33,255,866	1,344,685	7,051,386	13,587,983		(3,735,037)
State Income Taxes	2,708,787	(1,970,645)	77,687	2,993,028	121,022	634,625	1,222,919		(336,153)
Federal Income Taxes	5,751,658	(4,184,336)	164,956	6,355,196	256,969	1,347,520	2,596,664		(713,766)
Total Income Taxes	8,460,446	(6,154,981)	242,644	9,348,224	377,991	1,982,145	3,819,582		(1,049,919)
Amortization of Fed Income Tax Credit	(97,035)	(57,822)	(949)	(28,976)	(1,609)	(2,638)	(763)		(4,211)
Federal Tax Reform Amortization	(6,653,658)	(3,964,836)	(65,086)	(1,986,876)	(110,306)	(180,893)	(52,316)		(288,752)
Total Operating Income	**94,086,848**	**27,430,821**	**1,329,255**	**45,542,130**	**2,167,779**	**7,038,931**	**10,338,054**		**459,010**

Jersey Central Power & Light - First Energy Corp. Allocation Summary	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
Revenue Requirement									
Primary									
- Demand	153,618,941	97,530,414	1,274,079	44,786,116	2,095,516	6,041,175	840,221		948,372
- Customer	82,860	16,978	518	5,830	49	191	59,292		-
- Commodity	137,146,405	70,275,320	1,457,780	48,390,136	3,284,031	11,267,693	1,458,121		839,773
Secondary									
- Demand	198,185,059	129,717,888	1,694,557	59,577,202	2,787,920	1,793,661	1,203,601		1,262,696
- Customer	30,463,099	26,576,883	376,571	3,436,438	5,035	294	67,875		-
- Commodity	169,430,281	92,632,471	1,921,482	63,771,572	4,327,530	3,334,103	2,087,577		1,107,100
Customer Service									
- Demand	54,921,076	15,966,074	431,098	8,824,150	316,312	843,197	411,912		28,077,679
- Customer	76,285,938	63,325,972	880,545	8,100,068	68,880	1,897,017	1,868,898		124,697
- Commodity	19,941,372	9,923,715	205,800	6,822,996	462,758	1,587,603	732,552		118,714
		29.07%							
Total Revenue Requirement									
- Demand	**406,725,077**	**243,214,376**	**3,399,735**	**113,187,468**	**5,199,748**	**8,678,033**	**2,455,734**		**30,288,747**
- Customer	**106,831,896**	**89,919,834**	**1,257,635**	**11,542,335**	**73,964**	**1,897,502**	**1,996,065**		**124,697**
- Commodity	**326,518,058**	**172,831,506**	**3,585,062**	**118,984,704**	**8,074,319**	**16,189,399**	**4,278,250**		**2,065,586**
Total Revenue Requirement	**840,075,031**	**505,965,716**	**8,242,431**	**243,714,507**	**13,348,031**	**26,764,934**	**8,730,049**		**32,479,031**
Rate Base									
Primary									
- Demand	554,187,624	352,646,749	4,606,767	161,753,525	7,562,497	21,807,956	2,139,788		3,405,970
- Customer	27,966	-	-	-	-	-	27,966		-
- Commodity	493,390,430	253,530,921	5,260,374	174,792,297	11,868,503	40,724,527	3,741,010		3,026,946
Secondary									
- Demand	771,001,532	510,464,864	6,668,409	234,142,215	10,946,901	1,997,265	1,648,037		4,930,225
- Customer	192,066,601	167,930,259	2,376,726	21,678,297	31,363	-	49,957		-
- Commodity	649,307,622	363,123,279	7,534,246	250,348,761	16,998,833	3,742,450	2,881,277		4,335,386
Customer Service									
- Demand	186,684,349	41,617,977	1,396,294	24,779,320	787,804	2,009,582	2,194,815		113,627,386
- Customer	91,176,046	67,395,055	893,316	8,409,334	231,135	7,163,868	6,964,377		43,041
- Commodity	49,653,101	23,504,026	487,672	16,204,424	1,100,290	3,775,438	3,842,664		280,618
Total Rate Base									
- Demand	**1,511,873,505**	**904,729,591**	**12,671,470**	**420,675,060**	**19,297,201**	**25,814,803**	**5,982,640**		**121,963,581**
- Customer	**283,270,613**	**235,325,314**	**3,270,043**	**30,087,631**	**262,498**	**7,163,868**	**7,042,301**		**43,041**
- Commodity	**1,192,351,152**	**640,158,225**	**13,282,293**	**441,345,482**	**29,967,626**	**48,242,415**	**10,464,951**		**7,642,950**
Total Rate Base	**2,987,495,271**	**1,780,213,130**	**29,223,805**	**892,108,172**	**49,527,326**	**81,221,085**	**23,489,892**		**129,649,572**

Jersey Central Power & Light - First Energy Corp. Allocation Summary	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
Total Expenses									
Primary									
- Demand	101,539,188	64,390,454	841,159	29,585,337	1,384,830	3,991,773	639,134		628,296
- Customer	80,232	16,978	518	5,830	49	191	56,664		-
- Commodity	90,780,065	46,449,765	963,437	31,964,039	2,168,689	7,440,607	1,106,560		555,316
Secondary									
- Demand	125,730,230	81,746,979	1,067,894	37,573,699	1,759,186	1,605,968	1,048,727		799,378
- Customer	12,413,650	10,795,646	153,219	1,399,221	2,087	294	63,180		-
- Commodity	108,411,631	58,507,980	1,213,451	40,245,060	2,730,065	2,982,407	1,816,809		699,682
Customer Service									
- Demand	37,377,424	12,055,027	299,882	6,495,515	242,278	654,346	205,654		17,399,551
- Customer	67,717,674	56,992,525	796,596	7,309,801	47,160	1,223,793	1,214,421		120,653
- Commodity	15,275,224	7,714,926	159,971	5,300,186	359,358	1,232,806	371,438		92,343
Total Expenses									
- Demand	**264,646,842**	**158,192,460**	**2,208,934**	**73,654,551**	**3,386,294**	**6,252,088**	**1,893,516**		**18,827,226**
- Customer	**80,211,555**	**67,805,150**	**950,332**	**8,714,852**	**49,296**	**1,224,278**	**1,334,265**		**120,653**
- Commodity	**214,466,920**	**112,672,670**	**2,336,860**	**77,509,285**	**5,258,112**	**11,655,820**	**3,294,807**		**1,347,340**
Total Expenses	**559,325,317**	**338,670,280**	**5,496,126**	**159,878,688**	**8,693,703**	**19,132,187**	**6,522,587**		**20,295,219**

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Total System	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
UTILITY PLANT									
Intangible Plant									
(301) Organizational Costs	51,634								
- Demand	26,735	16,274	213	7,465	349	1,006	1,131		157
- Customer	-	-	-	-	-	-	-		-
- Commodity	24,899	11,757	244	8,105	550	1,888	1,978		140
Total	51,634	28,031	457	15,570	899	2,895	3,109		298
(302) Franchises & Consents	2,742								
- Demand	1,420	864	11	396	19	53	60		8
- Customer	-	-	-	-	-	-	-		-
- Commodity	1,322	624	13	430	29	100	105		7
Total	2,742	1,489	24	827	48	154	165		16
(303) Misc. Intangible Plant	182,308,711								
- Demand	94,396,997	57,461,196	750,639	26,356,548	1,232,253	3,553,446	3,994,424		554,978
- Customer	-	-	-	-	-	-	-		-
- Commodity	87,911,713	41,509,912	861,266	28,618,257	1,943,197	6,667,713	6,983,484		495,593
Total	182,308,711	98,971,109	1,611,905	54,974,805	3,175,450	10,221,160	10,977,907		1,050,571
Total Intangible Plant	182,363,086								
- Demand	94,425,152	57,478,335	750,863	26,364,409	1,232,621	3,554,506	3,995,615		555,143
- Customer	-	-	-	-	-	-	-		-
- Commodity	87,937,934	41,522,293	861,523	28,626,792	1,943,777	6,669,702	6,985,567		495,741
Total	182,363,086	99,000,628	1,612,386	54,991,202	3,176,397	10,224,208	10,981,182		1,050,884
Distribution Plant									
(360) Land and Land Rights	32,657,627								
- Demand	17,546,358	11,447,713	149,546	5,250,886	245,496	342,151	-		110,566
- Customer	-	-	-	-	-	-	-		-
- Commodity	15,111,269	8,181,559	169,755	5,640,628	383,002	638,645	-		97,681
Total	32,657,627	19,629,272	319,301	10,891,514	628,498	980,796	-		208,246
(361) Structures and Improvements	91,400,169								
- Demand	49,107,674	32,039,159	418,540	14,695,859	687,079	957,592	-		309,444
- Customer	-	-	-	-	-	-	-		-
- Commodity	42,292,496	22,898,047	475,099	15,786,643	1,071,923	1,787,400	-		273,383
Total	91,400,169	54,937,206	893,640	30,482,503	1,759,001	2,744,992	-		582,827
(362) Station Equipment	589,900,638								
- Demand	316,943,045	206,782,117	2,701,278	94,847,709	4,434,435	6,180,342	-		1,997,165
- Customer	-	-	-	-	-	-	-		-
- Commodity	272,957,593	147,784,985	3,066,310	101,887,679	6,918,235	11,535,955	-		1,764,428
Total	589,900,638	354,567,102	5,767,588	196,735,388	11,352,670	17,716,297	-		3,761,593
(364) Poles, Towers & Fixtures	791,658,782								
- Demand	425,344,082	277,505,851	3,625,171	127,287,575	5,951,103	8,294,146	-		2,680,236
- Customer	-	-	-	-	-	-	-		-
- Commodity	366,314,700	198,330,488	4,115,051	136,735,359	9,284,414	15,481,489	-		2,367,899
Total	791,658,782	475,836,339	7,740,222	264,022,934	15,235,517	23,775,635	-		5,048,135
(365) Overhead Conductors & Devices	1,272,980,404								
- Demand	683,949,567	446,226,983	5,829,243	204,677,308	9,569,322	13,336,914	-		4,309,796
- Customer	-	-	-	-	-	-	-		-
- Commodity	589,030,837	318,913,692	6,616,966	219,869,263	14,929,257	24,894,099	-		3,807,561
Total	1,272,980,404	765,140,675	12,446,209	424,546,571	24,498,578	38,231,013	-		8,117,357
(366) Underground Conduit	124,359,206								
- Demand	66,108,679	42,428,330	554,258	19,461,208	909,874	2,345,223	-		409,786
- Customer	-	-	-	-	-	-	-		-
- Commodity	58,250,527	30,455,115	631,897	20,996,727	1,425,691	4,377,490	-		363,608
Total	124,359,206	72,883,445	1,186,155	40,457,935	2,335,565	6,722,712	-		773,394
(367) Underground Conductors & Device	695,373,903								
- Demand	373,611,941	243,754,419	3,184,262	111,806,323	5,227,305	7,285,377	-		2,354,255
- Customer	-	-	-	-	-	-	-		-
- Commodity	321,761,962	174,208,698	3,614,561	120,105,028	8,155,204	13,598,565	-		2,079,905
Total	695,373,903	417,963,117	6,798,824	231,911,352	13,382,509	20,883,942	-		4,434,160
(368) Line Transformers	909,589,450								
- Demand	495,172,748	329,488,924	4,304,247	151,131,394	7,065,878	-	-		3,182,305
- Customer	-	-	-	-	-	-	-		-
- Commodity	414,416,702	234,275,046	4,860,845	161,516,683	10,967,081	-	-		2,797,047
Total	909,589,450	563,763,971	9,165,092	312,648,077	18,032,959	-	-		5,979,351
(369) Services	483,989,081								
- Demand	740,996	493,060	6,441	226,159	10,574	-	-		4,762
- Customer	483,248,085	422,629,904	5,981,504	54,557,746	78,931	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	483,989,081	423,122,965	5,987,945	54,783,905	89,504	-	-		4,762
(370) Meters	200,512,098								
- Demand	30,745,667	13,982,060	1,489,551	15,134,683	139,373	-	-		-
- Customer	169,766,432	129,597,514	1,741,421	16,284,196	359,194	10,996,438	10,671,272		-
- Commodity	-	-	-	-	-	-	-		-
Total	200,512,098	143,579,575	3,230,972	31,418,880	498,567	10,996,438	10,671,272		-
(371) Installation on Customers' Premises	27,149,890								
- Demand	27,149,890	-	-	-	-	-	-		27,149,890
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	27,149,890	-	-	-	-	-	-		27,149,890
(373) Street Lighting & Signal Systems	265,095,805								
- Demand	265,095,805	-	-	-	-	-	-		265,095,805
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	265,095,805	-	-	-	-	-	-		265,095,805

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Total System	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
(374) Asset Retirement Costs	45,657								
- Demand	24,206	15,470	202	7,096	332	957	-		149
- Customer	-	-	-	-	-	-	-		-
- Commodity	21,451	11,117	231	7,664	520	1,786	-		133
Total	45,657	26,587	433	14,760	852	2,742	-		282
(375) Charging Stations	-								
- Demand	-	-	-	-	-	-	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	-	-	-	-	-	-	-		-
Total Distribution Plant	5,484,712,711								
- Demand	2,751,540,657	1,604,164,087	22,262,741	744,526,201	34,240,769	38,742,702	-		307,604,158
- Customer	653,014,516	552,227,419	7,722,925	70,841,942	438,125	10,996,438	10,671,272		-
- Commodity	2,080,157,537	1,135,058,748	23,550,713	782,545,675	53,135,327	72,315,428	-		13,551,645
Total	5,484,712,711	3,291,450,254	53,536,380	1,597,913,818	87,814,221	122,054,567	10,671,272		321,155,803
General Plant									
(389) Land and Land Rights	1,497,070								
- Demand	775,163	471,856	6,164	216,433	10,119	29,180	32,801		4,557
- Customer	-	-	-	-	-	-	-		-
- Commodity	721,907	340,868	7,072	235,005	15,957	54,753	57,346		4,070
Total	1,497,070	812,724	13,237	451,438	26,076	83,933	90,148		8,627
(390) Structures and Improvements	105,831,624								
- Demand	54,798,191	33,356,671	435,752	15,300,181	715,333	2,062,803	2,318,794		322,169
- Customer	-	-	-	-	-	-	-		-
- Commodity	51,033,433	24,096,827	499,972	16,613,120	1,128,041	3,870,660	4,053,967		287,696
Total	105,831,624	57,453,498	935,724	31,913,302	1,843,374	5,933,463	6,372,761		609,865
(391) Office Furniture & Equipment	35,911,125								
- Demand	18,594,297	11,318,692	147,861	5,191,706	242,729	699,957	786,821		109,319
- Customer	-	-	-	-	-	-	-		-
- Commodity	17,316,828	8,176,612	169,652	5,637,217	382,770	1,313,405	1,375,605		97,622
Total	35,911,125	19,495,305	317,513	10,828,923	625,499	2,013,361	2,162,425		206,941
(392) Transportation Equipment	17,437,527								
- Demand	9,028,917	5,496,068	71,797	2,520,960	117,863	339,881	382,060		53,083
- Customer	-	-	-	-	-	-	-		-
- Commodity	8,408,610	3,970,354	82,379	2,737,289	185,864	637,756	667,959		47,403
Total	17,437,527	9,466,423	154,176	5,258,249	303,727	977,637	1,050,019		100,485
(393) Stores Equipment	1,120,889								
- Demand	580,381	353,289	4,615	162,048	7,576	21,848	24,559		3,412
- Customer	-	-	-	-	-	-	-		-
- Commodity	540,508	255,216	5,295	175,954	11,947	40,995	42,937		3,047
Total	1,120,889	608,504	9,910	338,002	19,524	62,843	67,496		6,459
(394) Tools, Shop & Garage Equipment	24,160,384								
- Demand	12,509,922	7,615,021	99,478	3,492,890	163,304	470,919	529,359		73,548
- Customer	-	-	-	-	-	-	-		-
- Commodity	11,650,462	5,501,084	114,139	3,792,622	257,521	883,636	925,483		65,678
Total	24,160,384	13,116,104	213,617	7,285,513	420,825	1,354,555	1,454,842		139,226
(395) Laboratory Equipment	427,250								
- Demand	221,224	134,663	1,759	61,768	2,888	8,328	9,361		1,301
- Customer	-	-	-	-	-	-	-		-
- Commodity	206,026	97,281	2,018	67,068	4,554	15,626	16,366		1,161
Total	427,250	231,944	3,778	128,836	7,442	23,954	25,727		2,462
(396) Power Operated Equipment	2,049,275								
- Demand	1,061,087	645,903	8,438	296,266	13,851	39,943	44,900		6,238
- Customer	-	-	-	-	-	-	-		-
- Commodity	988,188	466,600	9,681	321,689	21,843	74,950	78,499		5,571
Total	2,049,275	1,112,503	18,119	617,954	35,694	114,893	123,399		11,809
(397) Communication Equipment	65,188,679								
- Demand	33,753,821	20,546,574	268,408	9,424,391	440,621	1,270,617	1,428,298		198,445
- Customer	-	-	-	-	-	-	-		-
- Commodity	31,434,858	14,842,825	307,966	10,233,117	694,835	2,384,195	2,497,105		177,211
Total	65,188,679	35,389,400	576,374	19,657,508	1,135,455	3,654,811	3,925,404		375,656
(398) Misc. Equipment	175,681								
- Demand	90,965	55,372	723	25,398	1,187	3,424	3,849		535
- Customer	-	-	-	-	-	-	-		-
- Commodity	84,716	40,001	830	27,578	1,873	6,425	6,730		478
Total	175,681	95,373	1,553	52,976	3,060	9,850	10,579		1,012
(399) Other Tangible Property	1,460,782								
- Demand	756,373	460,418	6,015	211,187	9,874	28,473	32,006		4,447
- Customer	-	-	-	-	-	-	-		-
- Commodity	704,409	332,606	6,901	229,309	15,570	53,426	55,956		3,971
Total	1,460,782	793,024	12,916	440,496	25,444	81,899	87,963		8,418
(SRVCO-PIS) Service Company PIS	139,697,969								
- Demand	72,333,729	44,030,877	575,193	20,196,272	944,241	2,722,904	3,060,813		425,264
- Customer	-	-	-	-	-	-	-		-
- Commodity	67,364,240	31,807,863	659,964	21,929,354	1,489,016	5,109,279	5,351,245		379,759
Total	139,697,969	75,838,740	1,235,157	42,125,626	2,433,257	7,832,183	8,412,057		805,023
Total General Plant	394,958,255								
- Demand	204,504,070	124,485,406	1,626,203	57,099,500	2,669,585	7,698,277	8,653,621		1,202,318
- Customer	-	-	-	-	-	-	-		-
- Commodity	190,454,185	89,928,136	1,865,870	61,999,323	4,209,792	14,445,105	15,129,198		1,073,666
Total	394,958,255	214,413,542	3,492,073	119,098,823	6,879,377	22,143,382	23,782,819		2,275,984
Total Utility Plant	6,062,034,052								
- Demand	3,050,469,880	1,786,127,827	24,639,807	827,990,110	38,142,975	49,995,484	12,649,236		309,361,619
- Customer	653,014,516	552,227,419	7,722,925	70,841,942	438,125	10,996,438	10,671,272		-
- Commodity	2,358,549,655	1,266,509,178	26,278,107	873,171,791	59,288,895	93,430,235	22,114,764		15,121,052
Total	6,062,034,052	3,604,864,424	58,640,839	1,772,003,843	97,869,995	154,422,157	45,435,272		324,482,672

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Total System	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
Additions to Utility Plant									
Construction Work in Progress	-								
- Demand	-	-	-	-	-	-	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	-	-	-	-	-	-	-		-
Total Additional to Utility Plant	-								
- Demand	-	-	-	-	-	-	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	-	-	-	-	-	-	-		-
Total Utility Plant	6,062,034,052								
- Demand	3,050,469,880	1,786,127,827	24,639,807	827,990,110	38,142,975	49,995,484	12,649,236		309,361,619
- Customer	653,014,516	552,227,419	7,722,925	70,841,942	438,125	10,996,438	10,671,272		-
- Commodity	2,358,549,655	1,266,509,178	26,278,107	873,171,791	59,288,895	93,430,235	22,114,764		15,121,052
Total	**6,062,034,052**	**3,604,864,424**	**58,640,839**	**1,772,003,843**	**97,869,995**	**154,422,157**	**45,435,272**		**324,482,672**
ACCUMULATED DEPRECIATION									
Accumulated Depreciation									
(108-303) Misc Intangible Plant	(116,359,793)								
- Demand	(60,249,535)	(36,675,005)	(479,100)	(16,822,249)	(786,494)	(2,268,012)	(2,549,468)		(354,218)
- Customer	-	-	-	-	-	-	-		-
- Commodity	(56,110,258)	(26,493,988)	(549,709)	(18,265,800)	(1,240,259)	(4,255,714)	(4,457,257)		(316,316)
Total	(116,359,793)	(63,168,993)	(1,028,810)	(35,088,049)	(2,026,753)	(6,523,726)	(7,006,725)		(670,534)
(108-360) Land & Land Rights	(18,452,075)								
- Demand	(9,913,969)	(6,468,139)	(84,496)	(2,966,834)	(138,709)	(193,321)	-		(62,471)
- Customer	-	-	-	-	-	-	-		-
- Commodity	(8,538,106)	(4,622,710)	(95,914)	(3,187,044)	(216,402)	(360,844)	-		(55,191)
Total	(18,452,075)	(11,090,849)	(180,410)	(6,153,877)	(355,111)	(554,165)	-		(117,663)
(108-361) Struct & Impmnts	(17,177,516)								
- Demand	(9,229,172)	(6,021,358)	(78,659)	(2,761,903)	(129,128)	(179,967)	-		(58,156)
- Customer	-	-	-	-	-	-	-		-
- Commodity	(7,948,345)	(4,303,401)	(89,289)	(2,966,902)	(201,454)	(335,919)	-		(51,379)
Total	(17,177,516)	(10,324,759)	(167,948)	(5,728,804)	(330,582)	(515,887)	-		(109,535)
(108-362) Station Equip	(204,667,338)								
- Demand	(109,964,094)	(71,743,515)	(937,215)	(32,907,623)	(1,538,537)	(2,144,283)	-		(692,921)
- Customer	-	-	-	-	-	-	-		-
- Commodity	(94,703,244)	(51,274,329)	(1,063,863)	(35,350,157)	(2,400,297)	(4,002,425)	-		(612,172)
Total	(204,667,338)	(123,017,844)	(2,001,078)	(68,257,780)	(3,938,834)	(6,146,709)	-		(1,305,093)
(108-364) Poles, Towers & Fixt	(302,580,911)								
- Demand	(162,571,303)	(106,065,865)	(1,385,581)	(48,650,746)	(2,274,579)	(3,170,116)	-		(1,024,416)
- Customer	-	-	-	-	-	-	-		-
- Commodity	(140,009,608)	(75,804,149)	(1,572,819)	(52,261,796)	(3,548,608)	(5,917,200)	-		(905,038)
Total	(302,580,911)	(181,870,013)	(2,958,400)	(100,912,542)	(5,823,186)	(9,087,316)	-		(1,929,454)
(108-365) OH Cond & Dev	(195,375,322)								
- Demand	(104,971,660)	(68,486,318)	(894,664)	(31,413,598)	(1,468,687)	(2,046,932)	-		(661,462)
- Customer	-	-	-	-	-	-	-		-
- Commodity	(90,403,661)	(48,946,445)	(1,015,563)	(33,745,239)	(2,291,322)	(3,820,713)	-		(584,379)
Total	(195,375,322)	(117,432,763)	(1,910,227)	(65,158,837)	(3,760,009)	(5,867,644)	-		(1,245,841)
(108-366) UG Conduit	(62,021,124)								
- Demand	(32,970,093)	(21,160,096)	(276,423)	(9,705,804)	(453,777)	(1,169,623)	-		(204,371)
- Customer	-	-	-	-	-	-	-		-
- Commodity	(29,051,031)	(15,188,747)	(315,143)	(10,471,606)	(711,028)	(2,183,166)	-		(181,341)
Total	(62,021,124)	(36,348,842)	(591,566)	(20,177,410)	(1,164,806)	(3,352,789)	-		(385,712)
(108-367) UG Cond & Dev	(234,990,019)								
- Demand	(126,255,928)	(82,372,743)	(1,076,068)	(37,783,083)	(1,766,481)	(2,461,972)	-		(795,581)
- Customer	-	-	-	-	-	-	-		-
- Commodity	(108,734,091)	(58,870,926)	(1,221,481)	(40,587,492)	(2,755,915)	(4,595,408)	-		(702,869)
Total	(234,990,019)	(141,243,668)	(2,297,549)	(78,370,575)	(4,522,396)	(7,057,380)	-		(1,498,450)
(108-368) Line Transformers	(315,307,756)								
- Demand	(171,650,856)	(114,216,819)	(1,492,060)	(52,389,461)	(2,449,376)	-	-		(1,103,141)
- Customer	-	-	-	-	-	-	-		-
- Commodity	(143,656,900)	(81,211,077)	(1,685,004)	(55,989,505)	(3,801,721)	-	-		(969,592)
Total	(315,307,756)	(195,427,896)	(3,177,065)	(108,378,966)	(6,251,097)	-	-		(2,072,733)
(108-369) Services	(191,180,068)								
- Demand	(292,700)	(194,763)	(2,544)	(89,335)	(4,177)	-	-		(1,881)
- Customer	(190,887,368)	(166,942,638)	(2,362,748)	(21,550,804)	(31,178)	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	(191,180,068)	(167,137,401)	(2,365,293)	(21,640,138)	(35,355)	-	-		(1,881)
(108-370) Meters	(67,885,351)								
- Demand	(10,409,249)	(4,733,765)	(504,302)	(5,123,996)	(47,186)	-	-		-
- Customer	(57,476,102)	(43,876,518)	(589,575)	(5,513,175)	(121,609)	(3,722,953)	(3,612,864)		-
- Commodity	-	-	-	-	-	-	-		-
Total	(67,885,351)	(48,610,283)	(1,093,877)	(10,637,172)	(168,795)	(3,722,953)	(3,612,864)		-
(108-371) Install on Cust Premise	(10,069,793)								
- Demand	(10,069,793)	-	-	-	-	-	-		(10,069,793)
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	(10,069,793)	-	-	-	-	-	-		(10,069,793)
(108-373) St Lt & Signal Sys	(99,523,237)								
- Demand	(99,523,237)	-	-	-	-	-	-		(99,523,237)
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	(99,523,237)	-	-	-	-	-	-		(99,523,237)

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Total System	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
(108-374) Asset Ret Costs	-								
- Demand	-	-	-	-	-	-	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	-	-	-	-	-	-	-		-
(108-389) Land & Land Rights	(7,224)								
- Demand	(3,741)	(2,277)	(30)	(1,044)	(49)	(141)	(158)		(22)
- Customer	-	-	-	-	-	-	-		-
- Commodity	(3,484)	(1,645)	(34)	(1,134)	(77)	(264)	(277)		(20)
Total	(7,224)	(3,922)	(64)	(2,178)	(126)	(405)	(435)		(42)
(108-390) Struct & Impmnts -	(58,687,376)								
- Demand	(30,387,534)	(18,497,453)	(241,640)	(8,484,491)	(396,677)	(1,143,897)	(1,285,853)		(178,654)
- Customer	-	-	-	-	-	-	-		-
- Commodity	(28,299,842)	(13,362,542)	(277,252)	(9,212,562)	(625,539)	(2,146,418)	(2,248,068)		(159,537)
Total	(58,687,376)	(31,859,995)	(518,892)	(17,697,054)	(1,022,216)	(3,290,315)	(3,533,921)		(338,192)
(108-391) Office Furn & Equip	(6,552,210)								
- Demand	(3,392,646)	(2,065,166)	(26,978)	(947,259)	(44,287)	(127,712)	(143,560)		(19,946)
- Customer	-	-	-	-	-	-	-		-
- Commodity	(3,159,564)	(1,491,874)	(30,954)	(1,028,546)	(69,839)	(239,639)	(250,988)		(17,812)
Total	(6,552,210)	(3,557,040)	(57,932)	(1,975,805)	(114,126)	(367,350)	(394,548)		(37,758)
(108-392) Transportation Equip	(5,404,888)								
- Demand	(2,798,578)	(1,703,546)	(22,254)	(781,390)	(36,532)	(105,349)	(118,422)		(16,453)
- Customer	-	-	-	-	-	-	-		-
- Commodity	(2,606,310)	(1,230,640)	(25,534)	(848,443)	(57,610)	(197,677)	(207,039)		(14,693)
Total	(5,404,888)	(2,934,186)	(47,788)	(1,629,832)	(94,142)	(303,026)	(325,461)		(31,146)
(108-393) Stores Equip	(1,001,584)								
- Demand	(518,607)	(315,685)	(4,124)	(144,800)	(6,770)	(19,522)	(21,945)		(3,049)
- Customer	-	-	-	-	-	-	-		-
- Commodity	(482,977)	(228,051)	(4,732)	(157,226)	(10,676)	(36,632)	(38,366)		(2,723)
Total	(1,001,584)	(543,736)	(8,856)	(302,025)	(17,446)	(56,154)	(60,311)		(5,772)
(108-394) Tools, Shop & Garage Equip	(11,197,840)								
- Demand	(5,798,091)	(3,529,405)	(46,106)	(1,618,883)	(75,688)	(218,261)	(245,347)		(34,088)
- Customer	-	-	-	-	-	-	-		-
- Commodity	(5,399,749)	(2,549,639)	(52,901)	(1,757,802)	(119,356)	(409,547)	(428,942)		(30,441)
Total	(11,197,840)	(6,079,044)	(99,007)	(3,376,685)	(195,044)	(627,808)	(674,290)		(64,529)
(108-395) Laboratory Equip	(437,931)								
- Demand	(226,755)	(138,030)	(1,803)	(63,312)	(2,960)	(8,536)	(9,595)		(1,333)
- Customer	-	-	-	-	-	-	-		-
- Commodity	(211,176)	(99,713)	(2,069)	(68,745)	(4,668)	(16,017)	(16,775)		(1,190)
Total	(437,931)	(237,743)	(3,872)	(132,057)	(7,628)	(24,553)	(26,370)		(2,524)
(108-396) Power Operated Equip	(1,256,882)								
- Demand	(650,797)	(396,152)	(5,175)	(181,709)	(8,495)	(24,498)	(27,539)		(3,826)
- Customer	-	-	-	-	-	-	-		-
- Commodity	(606,086)	(286,180)	(5,938)	(197,301)	(13,397)	(45,969)	(48,146)		(3,417)
Total	(1,256,882)	(682,332)	(11,113)	(379,010)	(21,892)	(70,467)	(75,684)		(7,243)
(108-397) Communication Equip	(13,697,169)								
- Demand	(7,092,210)	(4,317,159)	(56,397)	(1,980,213)	(92,581)	(266,977)	(300,108)		(41,696)
- Customer	-	-	-	-	-	-	-		-
- Commodity	(6,604,959)	(3,118,712)	(64,708)	(2,150,139)	(145,996)	(500,957)	(524,681)		(37,235)
Total	(13,697,169)	(7,435,871)	(121,105)	(4,130,352)	(238,577)	(767,933)	(824,789)		(78,931)
(108-398) MISC Equip	(224,207)								
- Demand	(116,091)	(70,667)	(923)	(32,414)	(1,515)	(4,370)	(4,912)		(683)
- Customer	-	-	-	-	-	-	-		-
- Commodity	(108,116)	(51,050)	(1,059)	(35,195)	(2,390)	(8,200)	(8,588)		(609)
Total	(224,207)	(121,717)	(1,982)	(67,609)	(3,905)	(12,570)	(13,501)		(1,292)
(108-399) Other Tangible Property	-								
- Demand	-	-	-	-	-	-	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	-	-	-	-	-	-	-		-
Service Company PIS	(89,349,869)								
- Demand	(46,264,160)	(28,161,849)	(367,890)	(12,917,398)	(603,930)	(1,741,551)	(1,957,675)		(271,996)
- Customer	-	-	-	-	-	-	-		-
- Commodity	(43,085,709)	(20,344,092)	(422,108)	(14,025,866)	(952,365)	(3,267,860)	(3,422,620)		(242,891)
Total	(89,349,869)	(48,505,941)	(789,998)	(26,943,263)	(1,556,295)	(5,009,411)	(5,380,295)		(514,887)
Total Accumulated Depreciation	(2,023,407,484)								
- Demand	(1,005,320,799)	(577,335,775)	(7,984,434)	(267,767,544)	(12,326,615)	(17,295,039)	(6,664,584)		(115,123,395)
- Customer	(248,363,470)	(210,819,156)	(2,952,324)	(27,063,979)	(152,787)	(3,722,953)	(3,612,864)		-
- Commodity	(769,723,215)	(409,479,909)	(8,496,075)	(282,308,499)	(19,168,919)	(32,340,569)	(11,651,747)		(4,888,845)
Total Accumulated Depreciation	**(2,023,407,484)**	**(1,197,634,840)**	**(19,432,832)**	**(577,140,022)**	**(31,648,321)**	**(53,358,561)**	**(21,929,195)**		**(120,012,240)**

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Total System	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
OTHER RATE BASE ITEMS									
Other Rate Base Items									
Materials and Supplies	26,179,976								
- Demand	13,201,409	7,563,804	105,944	3,517,013	161,329	185,455	-		1,667,863
- Customer	3,177,670	2,676,024	37,367	343,018	2,329	60,036	58,261		-
- Commodity	9,800,897	5,344,882	110,898	3,684,932	250,209	346,162	-		63,813
Total	26,179,976	15,584,710	254,210	7,544,963	413,867	591,653	58,261		1,731,677
Cash Working Capital	107,271,360								
- Demand	43,907,499	26,502,564	377,982	12,368,311	564,446	792,049	-		3,302,147
- Customer	28,784,327	24,649,680	346,613	3,171,220	12,747	279,609	262,941		58,668
- Commodity	34,579,535	18,703,780	388,075	12,894,982	875,577	1,485,498	7,430		223,307
Total	107,271,360	69,856,024	1,112,670	28,434,513	1,452,770	2,557,156	270,371		3,584,122
ADIT	(1,196,729,137)								
- Demand	(603,457,818)	(345,753,757)	(4,842,880)	(160,768,378)	(7,374,628)	(8,477,446)	-		(76,240,728)
- Customer	(145,256,448)	(122,325,385)	(1,708,123)	(15,679,886)	(106,448)	(2,744,354)	(2,663,203)		-
- Commodity	(448,014,872)	(244,323,221)	(5,069,329)	(168,444,215)	(11,437,465)	(15,823,629)	-		(2,917,013)
Total	(1,196,729,137)	(712,402,362)	(11,620,332)	(344,892,479)	(18,918,541)	(27,045,429)	(2,663,203)		(79,157,741)
Net /Loss on Reacq Debt	1,371,332								
- Demand	691,502	396,199	5,549	184,224	8,451	9,714	-		87,364
- Customer	166,449	140,173	1,957	17,968	122	3,145	3,052		-
- Commodity	513,380	279,970	5,809	193,020	13,106	18,132	-		3,343
Total	1,371,332	816,342	13,316	395,212	21,679	30,991	3,052		90,707
DTA for AMT	9,517,218								
- Demand	4,799,114	2,749,673	38,514	1,278,541	58,648	67,419	-		606,319
- Customer	1,155,180	972,816	13,584	124,697	847	21,825	21,180		-
- Commodity	3,562,924	1,943,027	40,315	1,339,585	90,959	125,840	-		23,198
Total	9,517,218	5,665,516	92,413	2,742,824	150,453	215,084	21,180		629,517
Net Operating Reserves	(9,351,760)								
- Demand	(4,666,686)	(2,987,263)	(39,740)	(1,374,988)	(63,974)	(103,224)	-		(97,497)
- Customer	(727,205)	(619,643)	(8,719)	(79,746)	(299)	(6,301)	(11,111)		(1,322)
- Commodity	(3,957,869)	(2,128,317)	(44,159)	(1,467,330)	(99,633)	(192,833)	(167)		(25,410)
Total	(9,351,760)	(5,735,223)	(92,618)	(2,922,064)	(163,906)	(302,358)	(11,278)		(124,229)
NOL	36,093,727								
- Demand	18,200,477	10,428,042	146,063	4,848,825	222,421	255,682	-		2,299,444
- Customer	4,380,980	3,689,372	51,518	472,910	3,211	82,771	80,323		-
- Commodity	13,512,269	7,368,865	152,893	5,080,330	344,958	477,246	-		87,978
Total	36,093,727	21,486,279	350,473	10,402,066	570,589	815,699	80,323		2,387,422
CTA	(964,275)								
- Demand	(485,232)	(284,116)	(3,919)	(131,707)	(6,067)	(7,953)	(2,012)		(49,210)
- Customer	(103,874)	(87,842)	(1,228)	(11,269)	(70)	(1,749)	(1,697)		-
- Commodity	(375,170)	(201,461)	(4,180)	(138,894)	(9,431)	(14,862)	(3,518)		(2,405)
Total	(964,275)	(573,418)	(9,328)	(281,869)	(15,568)	(24,564)	(7,227)		(51,615)
Regulatory Asset A&G Capitalization	54,917,355								
- Demand	29,058,415	18,571,335	242,605	8,518,380	398,262	1,148,466	-		179,368
- Customer	108,015	-	-	-	-	-	108,015		-
- Commodity	25,750,925	13,345,478	276,898	9,200,798	624,740	2,143,677	-		159,334
Total	54,917,355	31,916,814	519,503	17,719,178	1,023,001	3,292,143	108,015		338,701
Customer Deposits	(36,962,658)								
- Demand	-	-	-	-	-	-	-		-
- Customer	(36,962,658)	(32,304,391)	(457,206)	(4,170,208)	(6,033)	(19,249)	(5,538)		-
- Commodity	-	-	-	-	-	-	-		-
Total	(36,962,658)	(32,304,391)	(457,206)	(4,170,208)	(6,033)	(19,249)	(5,538)		-
Customer Advances	(49,827,476)								
- Demand	(25,125,802)	(14,395,937)	(201,640)	(6,693,814)	(307,053)	(352,970)	-		(3,174,388)
- Customer	(6,047,953)	(5,093,187)	(71,120)	(652,854)	(4,432)	(114,265)	(110,886)		-
- Commodity	(18,653,720)	(10,172,736)	(211,069)	(7,013,408)	(476,215)	(658,839)	-		(121,454)
Total	(49,827,476)	(29,661,860)	(483,829)	(14,360,076)	(787,700)	(1,126,074)	(110,886)		(3,295,842)
Customer Refunds	(278,071)								
- Demand	(140,219)	(80,339)	(1,125)	(37,356)	(1,714)	(1,970)	-		(17,715)
- Customer	(33,752)	(28,423)	(397)	(3,643)	(25)	(638)	(619)		-
- Commodity	(104,100)	(56,771)	(1,178)	(39,140)	(2,658)	(3,677)	-		(678)
Total	(278,071)	(165,533)	(2,700)	(80,139)	(4,396)	(6,284)	(619)		(18,393)
Total Other Rate Base Items	(1,058,762,409)								
- Demand	(524,017,339)	(297,289,793)	(4,172,647)	(138,290,949)	(6,339,879)	(6,484,778)	(2,012)		(71,437,032)
- Customer	(151,359,269)	(128,330,807)	(1,795,754)	(16,467,794)	(98,053)	(2,439,169)	(2,259,284)		57,346
- Commodity	(383,385,801)	(209,896,502)	(4,355,028)	(144,709,338)	(9,825,852)	(12,097,285)	3,745		(2,505,987)
Total	(1,058,762,409)	(635,517,102)	(10,323,429)	(299,468,081)	(16,263,784)	(21,021,232)	(2,257,551)		(73,885,674)

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Total System	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
Rate Base Adjustment									
Adjustment									
AMI	43,720,862								
- Demand	6,703,970	3,048,732	324,791	3,300,057	30,390	-	-		-
- Customer	37,016,892	28,258,220	379,710	3,550,704	78,321	2,397,729	2,326,828		-
- Commodity	-	-	-	-	-	-	-		-
Total	43,720,862	31,306,952	704,500	6,850,761	108,711	2,397,729	2,326,828		-
Delayed Recognition Pension & OPEB	(36,089,750)								
- Demand	(15,962,207)	(9,821,401)	(136,047)	(4,556,615)	(209,668)	(400,865)	-		(837,611)
- Customer	(7,038,056)	(6,010,362)	(84,515)	(773,242)	(3,108)	(68,178)	(83,651)		(14,305)
- Commodity	(13,089,487)	(6,974,542)	(144,711)	(4,808,472)	(326,498)	(749,966)	(1,812)		(83,270)
Total	(36,089,750)	(22,806,305)	(365,273)	(10,138,329)	(539,275)	(1,219,009)	(85,463)		(935,186)
Total Rate Base Adjustment	7,631,112								
- Demand	(9,258,237)	(6,772,668)	188,743	(1,256,557)	(179,279)	(400,865)	-		(837,611)
- Customer	29,978,836	22,247,858	295,195	2,777,462	75,213	2,329,552	2,243,177		(14,305)
- Commodity	(13,089,487)	(6,974,542)	(144,711)	(4,808,472)	(326,498)	(749,966)	(1,812)		(83,270)
Total	7,631,112	8,500,648	339,227	(3,287,568)	(430,564)	1,178,721	2,241,365		(935,186)
Total Rate Base	**2,987,495,271**								
- Demand	**1,511,873,505**	**904,729,591**	**12,671,470**	**420,675,060**	**19,297,201**	**25,814,803**	**5,982,640**		**121,963,581**
- Customer	**283,270,613**	**235,325,314**	**3,270,043**	**30,087,631**	**262,498**	**7,163,868**	**7,042,301**		**43,041**
- Commodity	**1,192,351,152**	**640,158,225**	**13,282,293**	**441,345,482**	**29,967,626**	**48,242,415**	**10,464,951**		**7,642,950**
Total	**2,987,495,271**	**1,780,213,130**	**29,223,805**	**892,108,172**	**49,527,326**	**81,221,085**	**23,489,892**		**129,649,572**
OPERATIONS & MAINTENANCE EXPENSES									
Distribution Expenses									
Operations Expenses									
(580) Operation Supervision & Engineering	392,311								
- Demand	211,283	138,345	1,807	63,456	2,967	3,372	-		1,336
- Customer	-	-	-	-	-	-	-		-
- Commodity	181,028	98,780	2,050	68,102	4,624	6,293	-		1,179
Total	392,311	237,124	3,857	131,558	7,591	9,665	-		2,516
(581) Load Dispatching	1,446,055								
- Demand	766,659	489,974	6,401	224,744	10,507	30,300	-		4,732
- Customer	-	-	-	-	-	-	-		-
- Commodity	679,396	352,099	7,306	242,748	16,483	56,557	-		4,204
Total	1,446,055	842,073	13,706	467,492	26,990	86,858	-		8,936
(582) Station Expenses	609,126								
- Demand	327,272	213,521	2,789	97,939	4,579	6,382	-		2,062
- Customer	-	-	-	-	-	-	-		-
- Commodity	281,854	152,601	3,166	105,208	7,144	11,912	-		1,822
Total	609,126	366,123	5,956	203,147	11,723	18,294	-		3,884
(583) Overhead line expenses	1,040,054								
- Demand	558,802	364,578	4,763	167,226	7,818	10,897	-		3,521
- Customer	-	-	-	-	-	-	-		-
- Commodity	481,252	260,560	5,406	179,638	12,198	20,339	-		3,111
Total	1,040,054	625,137	10,169	346,864	20,016	31,236	-		6,632
(584) Underground line expenses	3,974,417								
- Demand	2,135,383	1,393,181	18,200	639,030	29,877	41,640	-		13,456
- Customer	-	-	-	-	-	-	-		-
- Commodity	1,839,034	995,692	20,659	686,462	46,611	77,723	-		11,888
Total	3,974,417	2,388,873	38,859	1,325,492	76,488	119,362	-		25,343
(585) Street lighting and signal system expenses	-								
- Demand	-	-	-	-	-	-	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	-	-	-	-	-	-	-		-
(586) Meter expenses	3,863,627								
- Demand	592,432	269,417	28,702	291,627	2,686	-	-		-
- Customer	3,271,195	2,497,188	33,555	313,777	6,921	211,888	205,623		-
- Commodity	-	-	-	-	-	-	-		-
Total	3,863,627	2,766,606	62,257	605,404	9,607	211,888	205,623		-
(587) Customer installations expenses	-								
- Demand	-	-	-	-	-	-	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	-	-	-	-	-	-	-		-
(588) Miscellaneous distribution expenses	22,995,565								
- Demand	11,743,416	6,779,012	94,345	3,148,052	144,665	218,151	-		1,359,191
- Customer	2,351,248	1,972,721	27,509	252,687	1,852	48,702	47,262		-
- Commodity	8,900,901	4,801,603	99,626	3,310,378	224,777	407,191	-		57,327
Total	22,995,565	13,553,336	221,480	6,711,117	371,294	674,043	47,262		1,416,518
(589) Rents	3,791,923								
- Demand	2,042,177	1,337,184	17,468	613,345	28,676	32,588	-		12,915
- Customer	-	-	-	-	-	-	-		-
- Commodity	1,749,746	954,767	19,810	658,247	44,695	60,828	-		11,399
Total	3,791,923	2,291,951	37,278	1,271,592	73,371	93,416	-		24,314
Total Dist. Operations Expenses	38,113,078								
- Demand	18,377,424	10,985,213	174,475	5,245,420	231,775	343,329	-		1,397,214
- Customer	5,622,443	4,469,910	61,064	566,464	8,773	260,590	252,884		-
- Commodity	14,113,210	7,616,101	158,022	5,250,783	356,531	640,843	-		90,930
Total	38,113,078	23,071,223	393,561	11,062,666	597,079	1,244,762	252,884		1,488,143
Maintenance Expense									
(590) Maintenance Supervision and Engineering	3,029,283								
- Demand	1,631,450	1,068,247	13,955	489,988	22,909	26,034	-		10,317
- Customer	-	-	-	-	-	-	-		-
- Commodity	1,397,833	762,742	15,826	525,859	35,706	48,594	-		9,106
Total	3,029,283	1,830,989	29,781	1,015,847	58,615	74,628	-		19,424

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Total System	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
(591) Maintenance of Structures	50,499								
- Demand	26,773	17,111	224	7,848	367	1,058	-		165
- Customer	-	-	-	-	-	-	-		-
- Commodity	23,726	12,296	255	8,477	576	1,975	-		147
Total	50,499	29,407	479	16,326	943	3,033	-		312
(592) Maintenance of Station Equipment	11,973,912								
- Demand	6,433,368	4,197,302	54,831	1,925,236	90,011	125,450	-		40,539
- Customer	-	-	-	-	-	-	-		-
- Commodity	5,540,544	2,999,767	62,241	2,068,135	140,428	234,159	-		35,815
Total	11,973,912	7,197,068	117,072	3,993,371	230,439	359,609	-		76,354
(593) Maintenance of Overhead Lines	84,228,604								
- Demand	45,254,520	29,525,259	385,700	13,542,772	633,168	882,456	-		285,164
- Customer	-	-	-	-	-	-	-		-
- Commodity	38,974,084	21,101,389	437,821	14,547,970	987,816	1,647,154	-		251,933
Total	84,228,604	50,626,648	823,522	28,090,743	1,620,984	2,529,611	-		537,097
(594) Maintenance of underground lines	4,572,747								
- Demand	2,456,855	1,602,918	20,940	735,233	34,375	47,908	-		15,481
- Customer	-	-	-	-	-	-	-		-
- Commodity	2,115,892	1,145,588	23,769	789,805	53,628	89,424	-		13,677
Total	4,572,747	2,748,506	44,709	1,525,038	88,003	137,332	-		29,159
(595) Maintenance of line transformers	151,393								
- Demand	151,393	100,737	1,316	46,207	2,160	-	-		973
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	151,393	100,737	1,316	46,207	2,160	-	-		973
(596) Maintenance of street lighting and signal systems	4,146,141								
- Demand	4,146,141	-	-	-	-	-	-		4,146,141
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	4,146,141	-	-	-	-	-	-		4,146,141
(597) Maintenance of meters	4,075,777								
- Demand	624,962	284,211	30,278	307,640	2,833	-	-		-
- Customer	3,450,815	2,634,308	35,398	331,006	7,301	223,523	216,913		-
- Commodity	-	-	-	-	-	-	-		-
Total	4,075,777	2,918,519	65,675	638,646	10,134	223,523	216,913		-
(598) Maintenance of miscellaneous distribution plant	2,564,666								
- Demand	1,309,728	756,055	10,522	351,098	16,134	24,330	-		151,589
- Customer	262,232	220,015	3,068	28,182	207	5,432	5,271		-
- Commodity	992,706	535,517	11,111	369,202	25,069	45,413	-		6,394
Total	2,564,666	1,511,586	24,701	748,482	41,410	75,175	5,271		157,982
Total Dist. Maintenance Expenses	114,793,021								
- Demand	62,035,190	37,551,838	517,765	17,406,023	801,957	1,107,237	-		4,650,370
- Customer	3,713,047	2,854,323	38,466	359,188	7,508	228,954	222,184		-
- Commodity	49,044,784	26,557,299	551,023	18,309,448	1,243,223	2,066,719	-		317,072
Total	114,793,021	66,963,460	1,107,254	36,074,660	2,052,687	3,402,911	222,184		4,967,442
Total Distribution Expenses	152,906,099								
- Demand	80,412,615	48,537,051	692,240	22,651,443	1,033,731	1,450,566	-		6,047,583
- Customer	9,335,490	7,324,233	99,530	925,652	16,281	489,544	475,068		-
- Commodity	63,157,994	34,173,400	709,045	23,560,231	1,599,754	2,707,562	-		408,002
Total	152,906,099	90,034,684	1,500,815	47,137,326	2,649,766	4,647,673	475,068		6,455,585
Customer Account Expense									
(901) Supervision	42,924								
- Demand	-	-	-	-	-	-	-		-
- Customer	42,924	37,422	530	4,831	7	22	6		106
- Commodity	-	-	-	-	-	-	-		-
Total	42,924	37,422	530	4,831	7	22	6		106
(902) Meter reading expenses	15,227,521								
- Demand	-	-	-	-	-	-	-		-
- Customer	15,227,521	13,275,491	187,889	1,713,747	2,479	7,910	2,276		37,716
- Commodity	-	-	-	-	-	-	-		-
Total	15,227,521	13,275,491	187,889	1,713,747	2,479	7,910	2,276		37,716
(903) Customer records and collection expenses	16,190,497								
- Demand	-	-	-	-	-	-	-		-
- Customer	16,190,497	14,115,022	199,771	1,822,123	2,636	8,411	2,420		40,101
- Commodity	-	-	-	-	-	-	-		-
Total	16,190,497	14,115,022	199,771	1,822,123	2,636	8,411	2,420		40,101
(904) Uncollectible accounts	171,298								
- Demand	-	-	-	-	-	-	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	171,298	80,883	1,678	55,763	3,786	12,992	13,607		966
Total	171,298	80,883	1,678	55,763	3,786	12,992	13,607		966
(905) Miscellaneous customer accounts expenses	1,439,425								
- Demand	-	-	-	-	-	-	-		-
- Customer	1,439,425	1,254,904	17,761	161,997	234	748	215		3,565
- Commodity	-	-	-	-	-	-	-		-
Total	1,439,425	1,254,904	17,761	161,997	234	748	215		3,565
Total Customer Account Expenses	33,071,665								
- Demand	-	-	-	-	-	-	-		-
- Customer	32,900,367	28,682,837	405,950	3,702,698	5,357	17,091	4,917		81,488
- Commodity	171,298	80,883	1,678	55,763	3,786	12,992	13,607		966
Total	33,071,665	28,763,720	407,628	3,758,461	9,143	30,083	18,525		82,454

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Total System	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
Customer Service Expenses									
(907) Customer Service Supervision	46,097								
- Demand	-	-	-	-	-	-	-		-
- Customer	46,097	40,188	569	5,188	8	24	7		114
- Commodity	-	-	-	-	-	-	-		-
Total	46,097	40,188	569	5,188	8	24	7		114
(908) Customer Assistance	2,080,009								
- Demand	-	-	-	-	-	-	-		-
- Customer	2,080,009	1,813,371	25,665	234,090	339	1,081	311		5,152
- Commodity	-	-	-	-	-	-	-		-
Total	2,080,009	1,813,371	25,665	234,090	339	1,081	311		5,152
(909) Informational and instructional advertising	2,645								
- Demand	-	-	-	-	-	-	-		-
- Customer	2,645	2,306	33	298	0	1	0		7
- Commodity	-	-	-	-	-	-	-		-
Total	2,645	2,306	33	298	0	1	0		7
(910) Miscellaneous customer service and informational	8,351,286								
- Demand	-	-	-	-	-	-	-		-
- Customer	8,351,286	7,280,727	103,045	939,877	1,360	4,338	1,248		20,685
- Commodity	-	-	-	-	-	-	-		-
Total	8,351,286	7,280,727	103,045	939,877	1,360	4,338	1,248		20,685
Total Customer Service Expenses	10,480,037								
- Demand	-	-	-	-	-	-	-		-
- Customer	10,480,037	9,136,591	129,311	1,179,452	1,706	5,444	1,566		25,957
- Commodity	-	-	-	-	-	-	-		-
Total	10,480,037	9,136,591	129,311	1,179,452	1,706	5,444	1,566		25,957
Sales Expenses									
(911) Sales Exp	4								
- Demand	2	1	0	1	0	0	-		0
- Customer	-	-	-	-	-	-	-		-
- Commodity	2	1	0	1	0	0	-		0
Total	4	2	0	1	0	0	-		0
Total Sales Expenses	4								
- Demand	2	1	0	1	0	0	-		0
- Customer	-	-	-	-	-	-	-		-
- Commodity	2	1	0	1	0	0	-		0
Total	4	2	0	1	0	0	-		0
Administrative & General Expense									
Labor Related									
(920) Administrative and general salaries	13,475,844								
- Demand	7,130,472	4,557,110	59,531	2,090,275	97,727	281,815	-		44,014
- Customer	26,505	-	-	-	-	-	26,505		-
- Commodity	6,318,867	3,274,768	67,946	2,257,729	153,301	526,024	-		39,098
Total	13,475,844	7,831,878	127,478	4,348,004	251,028	807,839	26,505		83,112
(921) Office supplies and expenses	1,205,430								
- Demand	637,829	407,639	5,325	186,978	8,742	25,209	-		3,937
- Customer	2,371	-	-	-	-	-	2,371		-
- Commodity	565,230	292,932	6,078	201,957	13,713	47,053	-		3,497
Total	1,205,430	700,571	11,403	388,934	22,455	72,262	2,371		7,434
(922) Administrative expenses transferred—Credit	(1,200,145)								
- Demand	(635,033)	(405,852)	(5,302)	(186,158)	(8,703)	(25,098)	-		(3,920)
- Customer	(2,361)	-	-	-	-	-	(2,361)		-
- Commodity	(562,752)	(291,647)	(6,051)	(201,071)	(13,653)	(46,847)	-		(3,482)
Total	(1,200,145)	(697,499)	(11,353)	(387,229)	(22,356)	(71,945)	(2,361)		(7,402)
(923) Outside services employed	43,893,380								
- Demand	23,225,300	14,843,371	193,905	6,808,421	318,316	917,926	-		143,362
- Customer	86,332	-	-	-	-	-	86,332		-
- Commodity	20,581,747	10,666,540	221,314	7,353,853	499,331	1,713,360	-		127,349
Total	43,893,380	25,509,911	415,219	14,162,274	817,647	2,631,286	86,332		270,711
(926) Employee pensions and benefits	(2,710,024)								
- Demand	(1,433,955)	(916,446)	(11,972)	(420,359)	(19,653)	(56,674)	-		(8,851)
- Customer	(5,330)	-	-	-	-	-	(5,330)		-
- Commodity	(1,270,739)	(658,564)	(13,664)	(454,035)	(30,829)	(105,785)	-		(7,863)
Total	(2,710,024)	(1,575,009)	(25,636)	(874,394)	(50,482)	(162,458)	(5,330)		(16,714)
(426) Pension / OPEB Non-Service Cost	-								
- Demand	-	-	-	-	-	-	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	-	-	-	-	-	-	-		-
(924) Property insurance	275,013								
- Demand	145,518	93,001	1,215	42,658	1,994	5,751	-		898
- Customer	541	-	-	-	-	-	541		-
- Commodity	128,954	66,831	1,387	46,075	3,129	10,735	-		798
Total	275,013	159,832	2,602	88,733	5,123	16,486	541		1,696
(925) Injuries and damages	5,022,788								
- Demand	2,657,707	1,698,550	22,189	779,098	36,425	105,040	-		16,405
- Customer	9,879	-	-	-	-	-	9,879		-
- Commodity	2,355,201	1,220,589	25,325	841,513	57,139	196,062	-		14,573
Total	5,022,788	2,919,139	47,514	1,620,611	93,565	301,102	9,879		30,978
(935) Maintenance of general plant	4,492,676								
- Demand	2,377,209	1,519,283	19,847	696,871	32,581	93,954	-		14,674
- Customer	8,836	-	-	-	-	-	8,836		-
- Commodity	2,106,630	1,091,766	22,652	752,698	51,109	175,370	-		13,035
Total	4,492,676	2,611,049	42,499	1,449,570	83,690	269,323	8,836		27,708

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Total System	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
(929) Duplicate charges—Credit	-								
- Demand	-	-	-	-	-	-	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	-	-	-	-	-	-	-		-
(928) Regulatory commission expenses	4,819,478								
- Demand	2,550,130	1,629,797	21,291	747,562	34,951	100,788	-		15,741
- Customer	9,479	-	-	-	-	-	9,479		-
- Commodity	2,259,869	1,171,182	24,300	807,450	54,826	188,126	-		13,983
Total	4,819,478	2,800,979	45,591	1,555,013	89,777	288,914	9,479		29,724
(930.1) Gen Advertising Exp	773,089								
- Demand	409,065	261,435	3,415	119,916	5,606	16,167	-		2,525
- Customer	1,521	-	-	-	-	-	1,521		-
- Commodity	362,504	187,869	3,898	129,523	8,795	30,177	-		2,243
Total	773,089	449,303	7,313	249,438	14,401	46,345	1,521		4,768
(930.2) Misc Gen Exp	2,420,568								
- Demand	1,280,795	818,561	10,693	375,461	17,554	50,620	-		7,906
- Customer	4,761	-	-	-	-	-	4,761		-
- Commodity	1,135,012	588,223	12,205	405,540	27,536	94,486	-		7,023
Total	2,420,568	1,406,783	22,898	781,000	45,090	145,106	4,761		14,929
(931) Rents	2,143,204								
- Demand	1,134,033	724,765	9,468	332,438	15,543	44,820	-		7,000
- Customer	4,215	-	-	-	-	-	4,215		-
- Commodity	1,004,955	520,820	10,806	359,070	24,381	83,659	-		6,218
Total	2,143,204	1,245,585	20,274	691,508	39,924	128,479	4,215		13,218
(932) Institutional Ad - Newspaper	-								
- Demand	-	-	-	-	-	-	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	-	-	-	-	-	-	-		-
(933) Transportation expenses	-								
- Demand	-	-	-	-	-	-	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
	-	-	-	-	-	-	-		-
Total A&G Expense	74,611,301								
- Demand	39,479,071	25,231,213	329,606	11,573,161	541,082	1,560,318	-		243,691
- Customer	146,750	-	-	-	-	-	146,750		-
- Commodity	34,985,480	18,131,309	376,197	12,500,302	848,778	2,912,422	-		216,473
Total	74,611,301	43,362,522	705,802	24,073,463	1,389,861	4,472,740	146,750		460,163
O&M Adjustment									
Adjustment									
Int on Cust Deposits	517,477								
- Demand	-	-	-	-	-	-	-		-
- Customer	517,477	452,261	6,401	58,383	84	269	78		-
- Commodity	-	-	-	-	-	-	-		-
Total	517,477	452,261	6,401	58,383	84	269	78		-
Annualize Payroll Increase	5,227,469								
- Demand	2,312,068	1,422,594	19,706	660,009	30,370	58,064	-		121,325
- Customer	1,019,437	870,579	12,242	112,001	450	9,875	12,117		2,072
- Commodity	1,895,965	1,010,237	20,961	696,490	47,292	108,630	262		12,061
Total	5,227,469	3,303,410	52,908	1,468,500	78,112	176,569	12,379		135,458
Svngs Pln Match on Payroll Inc	156,824								
- Demand	69,362	42,678	591	19,800	911	1,742	-		3,640
- Customer	30,583	26,117	367	3,360	14	296	363		62
- Commodity	56,879	30,307	629	20,895	1,419	3,259	8		362
Total	156,824	99,102	1,587	44,055	2,343	5,297	371		4,064
Reclass Amortization of Net Loss on Reacquired Debt	619,772								
- Demand	310,924	181,270	2,516	84,131	3,869	4,378	-		34,759
- Customer	73,791	62,402	873	8,005	50	1,243	1,206		-
- Commodity	235,058	128,262	2,661	88,428	6,004	8,172	-		1,531
Total	619,772	371,934	6,050	180,564	9,923	13,792	1,206		36,291
BPU & RPA Assessments	843,045								
- Demand	222,640	-	-	143,863	11,348	27,994	20,802		18,233
- Customer	67,883	48,417	1,477	16,625	141	545	674		-
- Commodity	552,523	410,383	7,591	112,086	2,796	7,197	5,447		7,023
Total	843,045	458,800	9,068	272,575	14,284	35,736	26,923		25,257
Rate Case Exp	-								
- Demand	-	-	-	-	-	-	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	-	-	-	-	-	-	-		-
Pension Smoothing	14,294,389								
- Demand	6,322,293	3,890,050	53,885	1,804,779	83,045	158,774	-		331,760
- Customer	2,787,626	2,380,578	33,475	306,265	1,231	27,004	33,132		5,666
- Commodity	5,184,470	2,762,469	57,317	1,904,534	129,319	297,046	718		32,982
Total	14,294,389	9,033,096	144,677	4,015,578	213,595	482,824	33,850		370,408
OPEB Smoothing	4,904,994								
- Demand	2,169,439	1,334,836	18,490	619,294	28,496	54,482	-		113,841
- Customer	956,549	816,874	11,487	105,092	422	9,266	11,369		1,944
- Commodity	1,779,005	947,917	19,668	653,524	44,375	101,929	246		11,317
Total	4,904,994	3,099,628	49,645	1,377,910	73,293	165,677	11,615		127,102

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Total System	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	Lighting LTG
Normalize Vegetation Management Expense	8,276,658							
- Demand	4,446,900	2,901,277	37,901	1,330,770	62,218	86,714	-	28,021
- Customer	-	-	-	-	-	-	-	-
- Commodity	3,829,758	2,073,512	43,022	1,429,545	97,067	161,856	-	24,756
Total	8,276,658	4,974,788	80,923	2,760,315	159,285	248,570	-	52,777
ServCo Depr @ JCP&L Rates	1,872,457							
- Demand	969,533	590,173	7,710	270,703	12,656	36,497	41,026	5,700
- Customer	-	-	-	-	-	-	-	-
- Commodity	902,924	426,340	8,846	293,932	19,958	68,483	71,726	5,090
Total	1,872,457	1,016,513	16,556	564,635	32,614	104,980	112,752	10,790
SERP/EDCP	4,921,662							
- Demand	2,176,812	1,339,372	18,553	621,399	28,593	54,667	-	114,227
- Customer	959,800	819,650	11,526	105,449	424	9,298	11,408	1,951
- Commodity	1,785,051	951,138	19,735	655,745	44,525	102,275	247	11,356
Total	4,921,662	3,110,161	49,813	1,382,593	73,542	166,240	11,655	127,534
Advertising removal	(746,134)							
- Demand	(394,802)	(252,319)	(3,296)	(115,735)	(5,411)	(15,604)	-	(2,437)
- Customer	(1,468)	-	-	-	-	-	(1,468)	-
- Commodity	(349,865)	(181,318)	(3,762)	(125,007)	(8,488)	(29,125)	-	(2,165)
Total	(746,134)	(433,638)	(7,058)	(240,742)	(13,899)	(44,729)	(1,468)	(4,602)
BGS Administrative Labor included in BGS Deferral	637,271							
- Demand	329,970	200,859	2,624	92,131	4,307	12,421	13,963	1,940
- Customer	-	-	-	-	-	-	-	-
- Commodity	307,301	145,100	3,011	100,037	6,793	23,307	24,411	1,732
Total	637,271	345,959	5,635	192,168	11,100	35,729	38,374	3,672
Low Income O&M	1,764,122							
- Demand	913,439	556,027	7,264	255,041	11,924	34,385	38,652	5,370
- Customer	-	-	-	-	-	-	-	-
- Commodity	850,684	401,673	8,334	276,926	18,803	64,521	67,576	4,796
Total	1,764,122	957,700	15,598	531,967	30,727	98,906	106,228	10,166
Contract Labor/Fuel Costs	81,460							
- Demand	43,103	27,547	360	12,635	591	1,704	-	266
- Customer	160	-	-	-	-	-	160	-
- Commodity	38,197	19,796	411	13,648	927	3,180	-	236
Total	81,460	47,343	771	26,283	1,517	4,883	160	502
Total O&M Adjustment	43,371,467							
- Demand	19,891,681	12,234,364	166,303	5,798,820	272,918	516,217	114,443	776,646
- Customer	6,411,838	5,476,879	77,846	715,181	2,816	57,796	69,039	11,695
- Commodity	17,067,948	9,125,816	188,422	6,120,784	410,790	920,729	170,641	111,078
Total	43,371,467	26,837,058	432,572	12,634,785	686,523	1,494,743	354,124	899,420
Total O&M Expenses	314,440,573							
- Demand	139,783,369	86,002,630	1,188,149	40,023,425	1,847,732	3,527,102	114,443	7,067,920
- Customer	59,274,482	50,620,540	712,637	6,522,984	26,160	569,875	697,341	119,140
- Commodity	115,382,722	61,511,408	1,275,342	42,237,081	2,863,108	6,553,706	184,249	736,518
Total	**314,440,573**	**198,134,578**	**3,176,128**	**88,783,489**	**4,737,000**	**10,650,683**	**996,033**	**7,923,579**
DEPRECIATION EXPENSE								
Depreciation Expense								
(403-360) Land & Land Rights	133,315							
- Demand	71,628	46,732	610	21,435	1,002	1,397	-	451
- Customer	-	-	-	-	-	-	-	-
- Commodity	61,687	33,399	693	23,026	1,563	2,607	-	399
Total	133,315	80,131	1,303	44,461	2,566	4,004	-	850
(403-361) Struct & Impmnts	1,053,041							
- Demand	565,780	369,130	4,822	169,314	7,916	11,033	-	3,565
- Customer	-	-	-	-	-	-	-	-
- Commodity	487,261	263,813	5,474	181,881	12,350	20,593	-	3,150
Total	1,053,041	632,943	10,296	351,195	20,266	31,626	-	6,715
(403-362) Station Equip	8,786,195							
- Demand	4,720,665	3,079,888	40,234	1,412,696	66,048	92,052	-	29,747
- Customer	-	-	-	-	-	-	-	-
- Commodity	4,065,530	2,201,163	45,671	1,517,552	103,043	171,821	-	26,280
Total	8,786,195	5,281,052	85,905	2,930,249	169,091	263,873	-	56,027
(403-364) Poles, Towers & Fixt	18,139,318							
- Demand	9,745,931	6,358,506	83,064	2,916,547	136,358	190,044	-	61,412
- Customer	-	-	-	-	-	-	-	-
- Commodity	8,393,388	4,544,357	94,288	3,133,024	212,734	354,728	-	54,256
Total	18,139,318	10,902,863	177,352	6,049,571	349,092	544,772	-	115,668
(403-365) OH Cond & Dev	41,977,810							
- Demand	22,553,926	14,714,784	192,225	6,749,440	315,558	439,798	-	142,120
- Customer	-	-	-	-	-	-	-	-
- Commodity	19,423,885	10,516,500	218,201	7,250,410	492,307	820,908	-	125,558
Total	41,977,810	25,231,284	410,426	13,999,851	807,865	1,260,706	-	267,678
(403-366) UG Conduit	1,100,797							
- Demand	585,178	375,565	4,906	172,266	8,054	20,759	-	3,627
- Customer	-	-	-	-	-	-	-	-
- Commodity	515,619	269,581	5,593	185,858	12,620	38,748	-	3,219
Total	1,100,797	645,147	10,500	358,124	20,674	59,508	-	6,846
(403-367) UG Cond & Dev	12,821,695							
- Demand	6,888,867	4,494,481	58,713	2,061,548	96,384	134,332	-	43,409
- Customer	-	-	-	-	-	-	-	-
- Commodity	5,932,828	3,212,158	66,647	2,214,564	150,370	250,738	-	38,350
Total	12,821,695	7,706,639	125,361	4,276,112	246,754	385,070	-	81,760

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Total System	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
(403-368) Line Transformers	18,448,452								
- Demand	10,043,180	6,682,752	87,299	3,065,273	143,311	-	-		64,544
- Customer	-	-	-	-	-	-	-		-
- Commodity	8,405,272	4,751,607	98,589	3,275,910	222,436	-	-		56,730
Total	18,448,452	11,434,359	185,888	6,341,183	365,748	-	-		121,274
(403-369) Services	7,940,911								
- Demand	12,158	8,090	106	3,711	173	-	-		78
- Customer	7,928,753	6,934,178	98,140	895,140	1,295	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	7,940,911	6,942,268	98,245	898,851	1,469	-	-		78
(403-370) Meters	10,227,000								
- Demand	1,568,164	713,147	75,974	771,936	7,109	-	-		-
- Customer	8,658,836	6,610,044	88,820	830,566	18,320	560,867	544,282		-
- Commodity	-	-	-	-	-	-	-		-
Total	10,227,000	7,323,191	164,794	1,602,501	25,429	560,867	544,282		-
(403-371) Install on Cust Premise	1,173,277								
- Demand	1,173,277	-	-	-	-	-	-		1,173,277
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	1,173,277	-	-	-	-	-	-		1,173,277
(403-373) St Lt & Signal Sys	8,028,829								
- Demand	8,028,829	-	-	-	-	-	-		8,028,829
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	8,028,829	-	-	-	-	-	-		8,028,829
(403-374) Asset Ret Costs	-								
- Demand	-	-	-	-	-	-	-		-
- Customer	-	-	-	-	-	-	-		-
- Commodity	-	-	-	-	-	-	-		-
Total	-	-	-	-	-	-	-		-
(403-389) Land & Land Rights	425								
- Demand	220	134	2	61	3	8	9		1
- Customer	-	-	-	-	-	-	-		-
- Commodity	205	97	2	67	5	16	16		1
Total	425	231	4	128	7	24	26		2
(403-390) Struct & Impmnts -	1,351,046								
- Demand	699,553	425,831	5,563	195,322	9,132	26,334	29,602		4,113
- Customer	-	-	-	-	-	-	-		-
- Commodity	651,492	307,620	6,383	212,083	14,401	49,413	51,753		3,673
Total	1,351,046	733,451	11,945	407,405	23,532	75,747	81,355		7,786
(403-391) Office Furn & Equip	6,668,521								
- Demand	3,452,870	2,101,826	27,457	964,075	45,074	129,979	146,109		20,300
- Customer	-	-	-	-	-	-	-		-
- Commodity	3,215,651	1,518,357	31,504	1,046,804	71,079	243,893	255,443		18,128
Total	6,668,521	3,620,183	58,961	2,010,878	116,152	373,871	401,552		38,428
(403-392) Transportation Equip	1,548,578								
- Demand	801,833	488,091	6,376	223,879	10,467	30,184	33,930		4,714
- Customer	-	-	-	-	-	-	-		-
- Commodity	746,745	352,596	7,316	243,091	16,506	56,637	59,320		4,210
Total	1,548,578	840,687	13,692	466,971	26,973	86,821	93,249		8,924
(403-393) Stores Equip	20,260								
- Demand	10,490	6,386	83	2,929	137	395	444		62
- Customer	-	-	-	-	-	-	-		-
- Commodity	9,770	4,613	96	3,180	216	741	776		55
Total	20,260	10,999	179	6,109	353	1,136	1,220		117
(403-394) Tools, Shop & Garage Equip	930,182								
- Demand	481,636	293,181	3,830	134,477	6,287	18,131	20,380		2,832
- Customer	-	-	-	-	-	-	-		-
- Commodity	448,546	211,793	4,394	146,017	9,915	34,020	35,631		2,529
Total	930,182	504,974	8,224	280,494	16,202	52,151	56,012		5,360
(403-395) Laboratory Equip	19,083								
- Demand	9,881	6,015	79	2,759	129	372	418		58
- Customer	-	-	-	-	-	-	-		-
- Commodity	9,202	4,345	90	2,996	203	698	731		52
Total	19,083	10,360	169	5,754	332	1,070	1,149		110
(403-396) Power Operated Equip	58,193								
- Demand	30,131	18,342	240	8,413	393	1,134	1,275		177
- Customer	-	-	-	-	-	-	-		-
- Commodity	28,061	13,250	275	9,135	620	2,128	2,229		158
Total	58,193	31,591	515	17,548	1,014	3,263	3,504		335
(403-397) Communication Equip	3,293,153								
- Demand	1,705,151	1,037,957	13,559	476,094	22,259	64,188	72,154		10,025
- Customer	-	-	-	-	-	-	-		-
- Commodity	1,588,003	749,819	15,558	516,949	35,101	120,443	126,147		8,952
Total	3,293,153	1,787,775	29,117	993,043	57,360	184,631	198,301		18,977
(403-398) MISC Equip	(17,233)								
- Demand	(8,923)	(5,432)	(71)	(2,491)	(116)	(336)	(378)		(52)
- Customer	-	-	-	-	-	-	-		-
- Commodity	(8,310)	(3,924)	(81)	(2,705)	(184)	(630)	(660)		(47)
Total	(17,233)	(9,355)	(152)	(5,197)	(300)	(966)	(1,038)		(99)
Total Depreciation Expense	143,702,850								
- Demand	73,140,425	41,215,404	605,071	19,349,685	875,678	1,159,804	303,943		9,593,289
- Customer	16,587,589	13,544,222	186,960	1,725,706	19,616	560,867	544,282		-
- Commodity	53,974,835	28,951,145	600,691	19,959,842	1,355,285	2,167,502	531,386		345,652
Total	143,702,850	83,710,771	1,392,722	41,035,233	2,250,579	3,888,172	1,379,611		9,938,941

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Total System	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
Depreciation Adjustment									
Adjustment									
Annualize Deprec Exp	9,581,673								
- Demand	4,876,783	2,748,119	40,344	1,290,179	58,388	77,332	20,266		639,652
- Customer	1,106,010	903,088	12,466	115,065	1,308	37,397	36,291		-
- Commodity	3,598,879	1,930,375	40,052	1,330,862	90,366	144,523	35,431		23,047
Total	9,581,673	5,581,582	92,863	2,736,106	150,062	259,252	91,988		662,699
Average Net Salvage	4,309,921								
- Demand	2,162,178	1,260,562	17,494	585,053	26,907	30,444	-		241,717
- Customer	513,143	433,944	6,069	55,668	344	8,641	8,386		-
- Commodity	1,634,601	891,936	18,506	614,929	41,754	56,826	-		10,649
Total	4,309,921	2,586,442	42,069	1,255,651	69,005	95,911	8,386		252,366
Total Depreciation Adjustment	13,891,594								
- Demand	7,038,961	4,008,681	57,839	1,875,232	85,294	107,776	20,266		881,369
- Customer	1,619,153	1,337,032	18,535	170,733	1,652	46,038	44,677		-
- Commodity	5,233,480	2,822,311	58,559	1,945,791	132,120	201,348	35,431		33,696
Total	13,891,594	8,168,024	134,932	3,991,756	219,067	355,163	100,374		915,065
Total Depreciation Expense									
- Demand	80,179,386	45,224,085	662,910	21,224,917	960,972	1,267,580	324,209		10,474,658
- Customer	18,206,743	14,881,254	205,495	1,896,439	21,268	606,905	588,959		-
- Commodity	59,208,315	31,773,456	659,250	21,905,633	1,487,406	2,368,850	566,817		379,348
Total	**157,594,444**	**91,878,795**	**1,527,654**	**45,026,989**	**2,469,646**	**4,243,335**	**1,479,985**		**10,854,006**
Amortization, Accretion, Regulatory Debits and Credits									
Amort - Ltd Term Elec Prpty	12,450,296								
- Demand	6,278,136	3,597,085	50,383	1,672,571	76,723	88,196	-		793,178
- Customer	1,511,191	1,272,625	17,771	163,127	1,107	28,551	27,707		-
- Commodity	4,660,969	2,541,842	52,739	1,752,427	118,991	164,623	-		30,347
Total	12,450,296	7,411,552	120,893	3,588,125	196,821	281,370	27,707		823,526
Accretion Expense	403,950								
- Demand	209,160	127,319	1,663	58,399	2,730	7,874	8,851		1,230
- Customer	-	-	-	-	-	-	-		-
- Commodity	194,790	91,975	1,908	63,411	4,306	14,774	15,474		1,098
Total	403,950	219,295	3,572	121,810	7,036	22,648	24,324		2,328
Regulatory Debits	65,491,174								
- Demand	33,910,449	20,641,917	269,654	9,468,123	442,665	1,276,513	1,434,926		199,366
- Customer	-	-	-	-	-	-	-		-
- Commodity	31,580,725	14,911,701	309,395	10,280,602	698,059	2,395,258	2,508,693		178,033
Total	65,491,174	35,553,617	579,048	19,748,725	1,140,724	3,671,771	3,943,619		377,399
Regulatory Credits	27,279								
- Demand	14,125	8,598	112	3,944	184	532	598		83
- Customer	-	-	-	-	-	-	-		-
- Commodity	13,154	6,211	129	4,282	291	998	1,045		74
Total	27,279	14,809	241	8,226	475	1,529	1,643		157
Total Depreciation and Amortization	235,967,143								
- Demand	120,591,256	69,599,004	984,722	32,427,953	1,483,275	2,640,694	1,768,583		11,468,515
- Customer	19,717,933	16,153,879	223,265	2,059,566	22,375	635,456	616,665		-
- Commodity	95,657,954	49,325,186	1,023,421	34,006,355	2,309,052	4,944,503	3,092,029		588,901
Total	**235,967,143**	**135,078,068**	**2,231,409**	**68,493,875**	**3,814,702**	**8,220,653**	**5,477,278**		**12,057,416**
TAXES									
Taxes Other than Income									
(408) Payroll Taxes	3,540,635								
- Demand	1,557,944	956,830	13,279	444,085	20,423	39,337	-		83,989
- Customer	707,119	603,886	8,491	77,691	313	6,861	8,367		1,440
- Commodity	1,275,572	679,375	14,096	468,383	31,803	73,599	182		8,111
Total	3,540,635	2,240,092	35,866	990,158	52,540	119,798	8,549		93,540
(408) Property Taxes	5,376,967								
- Demand	2,714,274	1,633,996	22,784	759,088	34,864	44,955	10,489		206,801
- Customer	512,021	426,845	5,939	54,611	448	12,086	11,891		73
- Commodity	2,150,672	1,156,701	24,000	797,467	54,148	84,013	18,347		13,810
Total	5,376,967	3,217,542	52,723	1,611,165	89,461	141,054	40,727		220,684
Total Taxes Other than Income	8,917,602								
- Demand	4,272,218	2,590,826	36,063	1,203,173	55,288	84,293	10,489		290,790
- Customer	1,219,140	1,030,731	14,431	132,302	761	18,947	20,258		1,512
- Commodity	3,426,244	1,836,076	38,096	1,265,849	85,952	157,612	18,529		21,921
Total Taxes Other than Income	**8,917,602**	**5,457,634**	**88,589**	**2,601,324**	**142,001**	**260,852**	**49,276**		**314,224**
Total Expenses	**559,325,317**								
- Demand	**264,646,842**	**158,192,460**	**2,208,934**	**73,654,551**	**3,386,294**	**6,252,088**	**1,893,516**		**18,827,226**
- Customer	**80,211,555**	**67,805,150**	**950,332**	**8,714,852**	**49,296**	**1,224,278**	**1,334,265**		**120,653**
- Commodity	**214,466,920**	**112,672,670**	**2,336,860**	**77,509,285**	**5,258,112**	**11,655,820**	**3,294,807**		**1,347,340**
Total	**559,325,317**	**338,670,280**	**5,496,126**	**159,878,688**	**8,693,703**	**19,132,187**	**6,522,587**		**20,295,219**

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Total System	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	Lighting LTG
REVENUE REQUIREMENT CALCULATION								
Total Rate Base								
- Demand	1,511,873,505	904,729,591	12,671,470	420,675,060	19,297,201	25,814,803	5,982,640	121,963,581
- Customer	283,270,613	235,325,314	3,270,043	30,087,631	262,498	7,163,868	7,042,301	43,041
- Commodity	1,192,351,152	640,158,225	13,282,293	441,345,482	29,967,626	48,242,415	10,464,951	7,642,950
Total	2,987,495,271	1,780,213,130	29,223,805	892,108,172	49,527,326	81,221,085	23,489,892	129,649,572
Required Net Income								
- Demand	114,902,386	68,759,449	963,032	31,971,305	1,466,587	1,961,925	454,681	9,269,232
- Customer	21,528,567	17,884,724	248,523	2,286,660	19,950	544,454	535,215	3,271
- Commodity	90,618,688	48,652,025	1,009,454	33,542,257	2,277,540	3,666,424	795,336	580,864
Total	227,049,641	135,296,198	2,221,009	67,800,221	3,764,077	6,172,802	1,785,232	9,853,367
Interest Synchronization								
- Demand	33,248,094	19,896,198	278,662	9,251,200	424,371	567,702	131,566	2,682,140
- Customer	6,229,495	5,175,114	71,913	661,667	5,773	157,543	154,869	947
- Commodity	26,221,376	14,077,924	292,095	9,705,770	659,028	1,060,914	230,138	168,079
Total	65,698,964	39,149,236	642,670	19,618,636	1,089,171	1,786,159	516,574	2,851,165
Net Income Before Income Taxes								
- Demand	81,654,293	48,863,251	684,369	22,720,105	1,042,216	1,394,223	323,115	6,587,092
- Customer	15,299,072	12,709,610	176,611	1,624,993	14,177	386,911	380,345	2,325
- Commodity	64,397,312	34,574,101	717,359	23,836,487	1,618,512	2,605,509	565,198	412,786
Total	161,350,677	96,146,962	1,578,339	48,181,585	2,674,905	4,386,644	1,268,658	7,002,202
Taxable Income								
- Demand	113,582,268	67,969,469	951,967	31,603,985	1,449,738	1,939,384	449,457	9,162,738
- Customer	21,281,224	17,679,246	245,668	2,260,388	19,721	538,199	529,066	3,234
- Commodity	89,577,566	48,093,060	997,857	33,156,888	2,251,373	3,624,300	786,199	574,191
Total	224,441,058	133,741,774	2,195,492	67,021,262	3,720,831	6,101,883	1,764,721	9,740,162
NJ State Corporate Business Tax								
- Demand	10,222,404	6,117,252	85,677	2,844,359	130,476	174,545	40,451	824,646
- Customer	1,915,310	1,591,132	22,110	203,435	1,775	48,438	47,616	291
- Commodity	8,061,981	4,328,375	89,807	2,984,120	202,624	326,187	70,758	51,677
Total	20,199,695	12,036,760	197,594	6,031,914	334,875	549,169	158,825	876,615
Federal Taxable Income								
- Demand	103,359,864	61,852,217	866,290	28,759,626	1,319,261	1,764,840	409,006	8,338,091
- Customer	19,365,914	16,088,113	223,558	2,056,953	17,946	489,761	481,450	2,943
- Commodity	81,515,585	43,764,685	908,050	30,172,768	2,048,749	3,298,113	715,441	522,513
Total	204,241,363	121,705,015	1,997,898	60,989,348	3,385,956	5,552,713	1,605,896	8,863,547
Federal Income Tax								
- Demand	21,705,571	12,988,965	181,921	6,039,522	277,045	370,616	85,891	1,750,999
- Customer	4,066,842	3,378,504	46,947	431,960	3,769	102,850	101,104	618
- Commodity	17,118,273	9,190,584	190,690	6,336,281	430,237	692,604	150,243	109,728
Total	42,890,686	25,558,053	419,559	12,807,763	711,051	1,166,070	337,238	1,861,345
NJ Federal & State Income Tax	63,090,381							
- Demand	31,927,976	19,106,218	267,598	8,883,880	407,521	545,161	126,342	2,575,646
- Customer	5,982,152	4,969,636	69,057	635,395	5,543	151,288	148,720	909
- Commodity	25,180,254	13,518,959	280,497	9,320,401	632,861	1,018,791	221,000	161,405
Total	63,090,381	37,594,813	617,153	18,839,677	1,045,926	1,715,239	496,063	2,737,959
Tax Reform Amortization	(9,255,331)							
- Demand	(4,683,820)	(2,802,874)	(39,257)	(1,303,261)	(59,783)	(79,975)	(18,534)	(377,846)
- Customer	(877,579)	(729,043)	(10,131)	(93,212)	(813)	(22,194)	(21,817)	(133)
- Commodity	(3,693,932)	(1,983,225)	(41,149)	(1,367,299)	(92,840)	(149,456)	(32,421)	(23,678)
Total	(9,255,331)	(5,515,143)	(90,536)	(2,763,772)	(153,437)	(251,625)	(72,772)	(401,657)
Investment Tax Credit	(134,977)							
- Demand	(68,307)	(40,876)	(573)	(19,006)	(872)	(1,166)	(270)	(5,510)
- Customer	(12,798)	(10,632)	(148)	(1,359)	(12)	(324)	(318)	(2)
- Commodity	(53,871)	(28,923)	(600)	(19,940)	(1,354)	(2,180)	(473)	(345)
Total	(134,977)	(80,431)	(1,320)	(40,306)	(2,238)	(3,670)	(1,061)	(5,858)
Federal & State Income Taxes								
- Demand	27,175,848	16,262,468	227,769	7,561,612	346,866	464,020	107,538	2,192,289
- Customer	5,091,775	4,229,960	58,779	540,824	4,718	128,770	126,585	774
- Commodity	21,432,450	11,506,811	238,749	7,933,162	538,667	867,155	188,107	137,382
Total	53,700,073	31,999,239	525,296	16,035,598	890,251	1,459,945	422,230	2,330,444
Revenue Requirement								
- Demand	**406,725,077**	**243,214,376**	**3,399,735**	**113,187,468**	**5,199,748**	**8,678,033**	**2,455,734**	**30,288,747**
- Customer	**106,831,896**	**89,919,834**	**1,257,635**	**11,542,335**	**73,964**	**1,897,502**	**1,996,065**	**124,697**
- Commodity	**326,518,058**	**172,831,506**	**3,585,062**	**118,984,704**	**8,074,319**	**16,189,399**	**4,278,250**	**2,065,586**
Total	**840,075,031**	**505,965,716**	**8,242,431**	**243,714,507**	**13,348,031**	**26,764,934**	**8,730,049**	**32,479,031**

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG	Classification Factor
UTILITY PLANT											
Intangible Plant											
(301) Organizational Costs		17,406									AE-ALL
- Demand	DMD-ALL	9,013	5,486	72	2,516	118	339	381		53	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	8,394	3,963	82	2,732	186	637	667		47	48%
Total		17,406	9,449	154	5,249	303	976	1,048		100	
(302) Franchises & Consents		924									AE-ALL
- Demand	DMD-ALL	479	291	4	134	6	18	20		3	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	446	210	4	145	10	34	35		3	48%
Total		924	502	8	279	16	52	56		5	
(303) Misc. Intangible Plant		61,458,196									AE-ALL
- Demand	DMD-ALL	31,822,227	19,370,777	253,048	8,885,071	415,406	1,197,904	1,346,562		187,089	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	29,635,969	13,993,431	290,342	9,647,517	655,072	2,247,757	2,354,206		167,070	48%
Total		61,458,196	33,364,208	543,390	18,532,588	1,070,478	3,445,661	3,700,769		354,159	
Total Intangible Plant		61,476,527									
- Demand		31,831,718	19,376,555	253,124	8,887,721	415,530	1,198,262	1,346,964		187,145	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		29,644,808	13,997,605	290,429	9,650,395	655,268	2,248,427	2,354,908		167,120	
Total		61,476,527	33,374,159	543,552	18,538,116	1,070,797	3,446,689	3,701,873		354,264	
Distribution Plant											
(360) Land and Land Rights		16,328,813									AE-PRI
- Demand	DMD-PRI	8,657,091	5,532,777	72,277	2,537,798	118,650	342,151	-		53,437	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	7,671,722	3,975,889	82,494	2,741,104	186,123	638,645	-		47,469	47%
Total		16,328,813	9,508,666	154,770	5,278,902	304,773	980,796	-		100,906	
(361) Structures and Improvements		45,700,085									AE-PRI
- Demand	DMD-PRI	24,228,937	15,484,799	202,284	7,102,634	332,071	957,592	-		149,557	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	21,471,148	11,127,474	230,878	7,671,635	520,909	1,787,400	-		132,853	47%
Total		45,700,085	26,612,272	433,162	14,774,269	852,980	2,744,992	-		282,410	
(362) Station Equipment		294,950,319									AE-PRI
- Demand	DMD-PRI	156,374,604	99,939,559	1,305,551	45,840,706	2,143,200	6,180,342	-		965,247	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	138,575,715	71,817,196	1,490,096	49,513,064	3,361,967	11,535,955	-		857,437	47%
Total		294,950,319	171,756,755	2,795,647	95,353,770	5,505,167	17,716,297	-		1,822,684	
(364) Poles, Towers & Fixtures		395,829,391									AE-PRI
- Demand	DMD-PRI	209,857,933	134,120,942	1,752,076	61,519,169	2,876,219	8,294,146	-		1,295,381	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	185,971,458	96,380,153	1,999,739	66,447,549	4,511,829	15,481,489	-		1,150,698	47%
Total		395,829,391	230,501,096	3,751,815	127,966,719	7,388,048	23,775,635	-		2,446,079	
(365) Overhead Conductors & Devices		636,490,202									AE-PRI
- Demand	DMD-PRI	337,449,723	215,665,303	2,817,323	98,922,287	4,624,935	13,336,914	-		2,082,961	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	299,040,479	154,978,445	3,215,563	106,847,079	7,254,982	24,894,099	-		1,850,312	47%
Total		636,490,202	370,643,748	6,032,886	205,769,366	11,879,916	38,231,013	-		3,933,273	
(366) Underground Conduit		111,923,286									AE-PRI
- Demand	DMD-PRI	59,338,670	37,923,552	495,411	17,394,938	813,269	2,345,223	-		366,277	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	52,584,616	27,252,103	565,439	18,788,469	1,275,748	4,377,490	-		325,367	47%
Total		111,923,286	65,175,655	1,060,850	36,183,406	2,089,018	6,722,712	-		691,644	
(367) Underground Conductors & Device		347,686,952									AE-PRI
- Demand	DMD-PRI	184,334,127	117,808,588	1,538,981	54,036,949	2,526,401	7,285,377	-		1,137,831	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	163,352,825	84,657,993	1,756,522	58,365,918	3,963,081	13,598,565	-		1,010,745	47%
Total		347,686,952	202,466,581	3,295,504	112,402,867	6,489,482	20,883,942	-		2,148,576	
(368) Line Transformers		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(369) Services		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(370) Meters		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(371) Installation on Customers' Premises		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(373) Street Lighting & Signal Systems		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
(374) Asset Retirement Costs		45,657									AE-PRI
- Demand	DMD-PRI	24,206	15,470	202	7,096	332	957	-		149	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	21,451	11,117	231	7,664	520	1,786	-		133	47%
Total		45,657	26,587	433	14,760	852	2,742	-		282	
(375) Charging Stations		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
Total Distribution Plant		1,848,954,704									
- Demand		980,265,291	626,490,990	8,184,105	287,361,576	13,435,077	38,742,702	-		6,050,841	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		868,689,413	450,200,369	9,340,961	310,382,482	21,075,159	72,315,428	-		5,375,013	
Total		1,848,954,704	1,076,691,359	17,525,066	597,744,059	34,510,236	111,058,129	-		11,425,854	
General Plant											
(389) Land and Land Rights		526,704									AE-ALL
- Demand	DMD-ALL	272,720	166,010	2,169	76,146	3,560	10,266	11,540		1,603	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	253,984	119,925	2,488	82,680	5,614	19,264	20,176		1,432	48%
Total		526,704	285,935	4,657	158,826	9,174	29,530	31,716		3,035	
(390) Structures and Improvements		37,234,023									AE-ALL
- Demand	DMD-ALL	19,279,276	11,735,652	153,308	5,382,959	251,671	725,742	815,806		113,347	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	17,954,747	8,477,823	175,902	5,844,882	396,871	1,361,788	1,426,280		101,218	48%
Total		37,234,023	20,213,475	329,209	11,227,841	648,542	2,087,530	2,242,085		214,565	
(391) Office Furniture & Equipment		12,634,368									AE-ALL
- Demand	DMD-ALL	6,541,906	3,982,179	52,021	1,826,563	85,398	246,261	276,822		38,461	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	6,092,462	2,876,722	59,688	1,983,304	134,668	462,086	483,970		34,346	48%
Total		12,634,368	6,858,901	111,708	3,809,867	220,065	708,347	760,792		72,807	
(392) Transportation Equipment		6,134,927									AE-ALL
- Demand	DMD-ALL	3,176,583	1,933,645	25,260	886,932	41,467	119,578	134,418		18,676	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	2,958,344	1,396,863	28,983	963,042	65,391	224,377	235,003		16,677	48%
Total		6,134,927	3,330,507	54,243	1,849,974	106,858	343,955	369,421		35,353	
(393) Stores Equipment		394,355									AE-ALL
- Demand	DMD-ALL	204,192	124,295	1,624	57,012	2,666	7,687	8,640		1,200	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	190,163	89,791	1,863	61,905	4,203	14,423	15,106		1,072	48%
Total		394,355	214,086	3,487	118,917	6,869	22,110	23,746		2,273	
(394) Tools, Shop & Garage Equipment		8,500,184									AE-ALL
- Demand	DMD-ALL	4,401,281	2,679,141	34,999	1,228,880	57,454	165,680	186,241		25,876	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	4,098,903	1,935,409	40,157	1,334,333	90,602	310,884	325,606		23,107	48%
Total		8,500,184	4,614,550	75,155	2,563,213	148,056	476,564	511,847		48,983	
(395) Laboratory Equipment		150,316									AE-ALL
- Demand	DMD-ALL	77,832	47,378	619	21,731	1,016	2,930	3,293		458	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	72,485	34,226	710	23,596	1,602	5,498	5,758		409	48%
Total		150,316	81,603	1,329	45,328	2,618	8,428	9,051		866	
(396) Power Operated Equipment		720,982									AE-ALL
- Demand	DMD-ALL	373,315	227,244	2,969	104,233	4,873	14,053	15,797		2,195	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	347,667	164,161	3,406	113,178	7,685	26,369	27,618		1,960	48%
Total		720,982	391,404	6,375	217,411	12,558	40,422	43,415		4,155	
(397) Communication Equipment		22,934,891									AE-ALL
- Demand	DMD-ALL	11,875,378	7,228,762	94,432	3,315,720	155,021	447,032	502,508		69,818	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	11,059,513	5,222,051	108,349	3,600,248	244,459	838,815	878,540		62,347	48%
Total		22,934,891	12,450,813	202,782	6,915,968	399,480	1,285,847	1,381,048		132,164	
(398) Misc. Equipment		61,809									AE-ALL
- Demand	DMD-ALL	32,004	19,481	254	8,936	418	1,205	1,354		188	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	29,805	14,073	292	9,703	659	2,261	2,368		168	48%
Total		61,809	33,555	546	18,638	1,077	3,465	3,722		356	
(399) Other Tangible Property		513,937									AE-ALL
- Demand	DMD-ALL	266,110	161,986	2,116	74,300	3,474	10,017	11,260		1,565	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	247,827	117,018	2,428	80,676	5,478	18,797	19,687		1,397	48%
Total		513,937	279,004	4,544	154,977	8,952	28,814	30,947		2,962	
(SRVCO-PIS) Service Company PIS		49,148,990									AE-ALL
- Demand	DMD-ALL	25,448,686	15,491,085	202,366	7,105,517	332,206	957,981	1,076,865		149,618	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	23,700,304	11,190,745	232,191	7,715,256	523,871	1,797,563	1,882,692		133,608	48%
Total		49,148,990	26,681,830	434,557	14,820,774	856,076	2,755,544	2,959,557		283,226	
Total General Plant		138,955,488									
- Demand		71,949,282	43,796,857	572,136	20,088,930	939,222	2,708,433	3,044,545		423,003	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		67,006,206	31,638,807	656,456	21,812,802	1,481,103	5,082,123	5,322,803		377,741	
Total		138,955,488	75,435,664	1,228,592	41,901,732	2,420,325	7,790,556	8,367,348		800,744	
Total Utility Plant		2,049,386,718									
- Demand		1,084,046,291	689,664,402	9,009,365	316,338,228	14,789,828	42,649,396	4,391,509		6,660,989	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		965,340,427	495,836,781	10,287,846	341,845,679	23,211,529	79,645,978	7,677,712		5,919,873	
Total		2,049,386,718	1,185,501,183	19,297,211	658,183,907	38,001,358	122,295,374	12,069,221		12,580,863	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
Additions to Utility Plant											
Construction Work in Progress		-									
- Demand		-	-	-	-	-	-	-		-	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		-	-	-	-	-	-	-		-	
Total		-	-	-	-	-	-	-		-	
Total Additional to Utility Plant		-									
- Demand		-	-	-	-	-	-	-		-	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		-	-	-	-	-	-	-		-	
Total		-	-	-	-	-	-	-		-	
Total Utility Plant		2,049,386,718									
- Demand		1,084,046,291	689,664,402	9,009,365	316,338,228	14,789,828	42,649,396	4,391,509		6,660,989	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		965,340,427	495,836,781	10,287,846	341,845,679	23,211,529	79,645,978	7,677,712		5,919,873	
Total		**2,049,386,718**	**1,185,501,183**	**19,297,211**	**658,183,907**	**38,001,358**	**122,295,374**	**12,069,221**		**12,580,863**	
ACCUMULATED DEPRECIATION											
Accumulated Depreciation											
(108-303) Misc Intangible Plant		(39,337,657)									AE-ALL
- Demand	DMD-ALL	(20,368,509)	(12,398,688)	(161,969)	(5,687,083)	(265,889)	(766,745)	(861,897)		(119,750)	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(18,969,147)	(8,956,800)	(185,840)	(6,175,103)	(419,293)	(1,438,726)	(1,506,861)		(106,937)	48%
Total		(39,337,657)	(21,355,488)	(347,809)	(11,862,187)	(685,183)	(2,205,470)	(2,368,758)		(226,687)	
(108-360) Land & Land Rights		(9,226,037)									AE-PRI
- Demand	DMD-PRI	(4,891,393)	(3,126,106)	(40,838)	(1,433,896)	(67,039)	(193,321)	-		(30,193)	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	(4,334,644)	(2,246,440)	(46,610)	(1,548,767)	(105,162)	(360,844)	-		(26,821)	47%
Total		(9,226,037)	(5,372,546)	(87,448)	(2,982,663)	(172,201)	(554,165)	-		(57,013)	
(108-361) Struct & Impmnts		(8,588,758)									AE-PRI
- Demand	DMD-PRI	(4,553,525)	(2,910,174)	(38,017)	(1,334,851)	(62,409)	(179,967)	-		(28,107)	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	(4,035,233)	(2,091,269)	(43,391)	(1,441,788)	(97,898)	(335,919)	-		(24,968)	47%
Total		(8,588,758)	(5,001,443)	(81,407)	(2,776,639)	(160,307)	(515,887)	-		(53,075)	
(108-362) Station Equip		(102,333,669)									AE-PRI
- Demand	DMD-PRI	(54,254,517)	(34,674,252)	(452,964)	(15,904,535)	(743,588)	(2,144,283)	-		(334,895)	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	(48,079,152)	(24,917,136)	(516,992)	(17,178,668)	(1,166,442)	(4,002,425)	-		(297,490)	47%
Total		(102,333,669)	(59,591,388)	(969,956)	(33,083,202)	(1,910,030)	(6,146,709)	-		(632,384)	
(108-364) Poles, Towers & Fixt		(151,290,456)									AE-PRI
- Demand	DMD-PRI	(80,210,068)	(51,262,536)	(669,663)	(23,513,320)	(1,099,323)	(3,170,116)	-		(495,109)	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	(71,080,388)	(36,837,581)	(764,323)	(25,397,002)	(1,724,472)	(5,917,200)	-		(439,810)	47%
Total		(151,290,456)	(88,100,117)	(1,433,986)	(48,910,323)	(2,823,795)	(9,087,316)	-		(934,919)	
(108-365) OH Cond & Dev		(97,687,661)									AE-PRI
- Demand	DMD-PRI	(51,791,330)	(33,100,021)	(432,399)	(15,182,460)	(709,829)	(2,046,932)	-		(319,690)	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	(45,896,331)	(23,785,883)	(493,520)	(16,398,746)	(1,113,485)	(3,820,713)	-		(283,983)	47%
Total		(97,687,661)	(56,885,904)	(925,919)	(31,581,206)	(1,823,314)	(5,867,644)	-		(603,674)	
(108-366) UG Conduit		(55,819,012)									AE-PRI
- Demand	DMD-PRI	(29,593,716)	(18,913,448)	(247,074)	(8,675,301)	(405,598)	(1,169,623)	-		(182,672)	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	(26,225,296)	(13,591,323)	(281,999)	(9,370,291)	(636,248)	(2,183,166)	-		(162,269)	47%
Total		(55,819,012)	(32,504,770)	(529,073)	(18,045,592)	(1,041,847)	(3,352,789)	-		(344,941)	
(108-367) UG Cond & Dev		(117,495,009)									AE-PRI
- Demand	DMD-PRI	(62,292,645)	(39,811,448)	(520,073)	(18,260,886)	(853,755)	(2,461,972)	-		(384,511)	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	(55,202,364)	(28,608,757)	(593,587)	(19,723,789)	(1,339,257)	(4,595,408)	-		(341,564)	47%
Total		(117,495,009)	(68,420,206)	(1,113,661)	(37,984,675)	(2,193,012)	(7,057,380)	-		(726,076)	
(108-368) Line Transformers		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(108-369) Services		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(108-370) Meters		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(108-371) Install on Cust Premise		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(108-373) St Lt & Signal Sys		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
(108-374) Asset Ret Costs		-									AE-PRI
- Demand	DMD-PRI	-	-	-	-	-	-	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	-	-	-	-	-	-	-		-	47%
Total		-	-	-	-	-	-	-		-	
(108-389) Land & Land Rights		(2,435)									AE-ALL
- Demand	DMD-ALL	(1,261)	(768)	(10)	(352)	(16)	(47)	(53)		(7)	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(1,174)	(554)	(12)	(382)	(26)	(89)	(93)		(7)	48%
Total		(2,435)	(1,322)	(22)	(734)	(42)	(137)	(147)		(14)	
(108-390) Struct & Impmnts -		(19,784,136)									AE-ALL
- Demand	DMD-ALL	(10,243,959)	(6,235,687)	(81,459)	(2,860,212)	(133,724)	(385,620)	(433,475)		(60,226)	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(9,540,176)	(4,504,654)	(93,465)	(3,105,652)	(210,876)	(723,580)	(757,847)		(53,782)	48%
Total		(19,784,136)	(10,740,342)	(174,924)	(5,965,864)	(344,600)	(1,109,200)	(1,191,322)		(114,008)	
(108-391) Office Furn & Equip		(2,208,819)									AE-ALL
- Demand	DMD-ALL	(1,143,697)	(696,189)	(9,095)	(319,331)	(14,930)	(43,053)	(48,396)		(6,724)	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(1,065,122)	(502,927)	(10,435)	(346,734)	(23,543)	(80,785)	(84,611)		(6,005)	48%
Total		(2,208,819)	(1,199,116)	(19,530)	(666,065)	(38,473)	(123,838)	(133,006)		(12,729)	
(108-392) Transportation Equip		(1,822,045)									AE-ALL
- Demand	DMD-ALL	(943,430)	(574,283)	(7,502)	(263,415)	(12,315)	(35,514)	(39,921)		(5,547)	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(878,615)	(414,862)	(8,608)	(286,019)	(19,421)	(66,639)	(69,795)		(4,953)	48%
Total		(1,822,045)	(989,145)	(16,110)	(549,434)	(31,736)	(102,153)	(109,716)		(10,500)	
(108-393) Stores Equip		(337,645)									AE-ALL
- Demand	DMD-ALL	(174,828)	(106,421)	(1,390)	(48,814)	(2,282)	(6,581)	(7,398)		(1,028)	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(162,817)	(76,878)	(1,595)	(53,002)	(3,599)	(12,349)	(12,934)		(918)	48%
Total		(337,645)	(183,299)	(2,985)	(101,816)	(5,881)	(18,930)	(20,332)		(1,946)	
(108-394) Tools, Shop & Garage Equip		(3,774,911)									AE-ALL
- Demand	DMD-ALL	(1,954,598)	(1,189,800)	(15,543)	(545,742)	(25,515)	(73,578)	(82,709)		(11,491)	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(1,820,313)	(859,510)	(17,834)	(592,574)	(40,236)	(138,063)	(144,601)		(10,262)	48%
Total		(3,774,911)	(2,049,310)	(33,376)	(1,138,316)	(65,751)	(211,641)	(227,310)		(21,753)	
(108-395) Laboratory Equip		(147,631)									AE-ALL
- Demand	DMD-ALL	(76,441)	(46,531)	(608)	(21,343)	(998)	(2,878)	(3,235)		(449)	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(71,190)	(33,614)	(697)	(23,175)	(1,574)	(5,399)	(5,655)		(401)	48%
Total		(147,631)	(80,146)	(1,305)	(44,518)	(2,571)	(8,277)	(8,890)		(851)	
(108-396) Power Operated Equip		(423,708)									AE-ALL
- Demand	DMD-ALL	(219,390)	(133,547)	(1,745)	(61,256)	(2,864)	(8,259)	(9,284)		(1,290)	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(204,318)	(96,474)	(2,002)	(66,512)	(4,516)	(15,497)	(16,230)		(1,152)	48%
Total		(423,708)	(230,021)	(3,746)	(127,768)	(7,380)	(23,755)	(25,514)		(2,442)	
(108-397) Communication Equip		(4,617,461)									AE-ALL
- Demand	DMD-ALL	(2,390,859)	(1,455,360)	(19,012)	(667,551)	(31,210)	(90,001)	(101,170)		(14,056)	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(2,226,602)	(1,051,351)	(21,814)	(724,835)	(49,217)	(168,878)	(176,876)		(12,552)	48%
Total		(4,617,461)	(2,506,711)	(40,826)	(1,392,385)	(80,427)	(258,878)	(278,045)		(26,609)	
(108-398) MISC Equip		(75,583)									AE-ALL
- Demand	DMD-ALL	(39,136)	(23,823)	(311)	(10,927)	(511)	(1,473)	(1,656)		(230)	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(36,447)	(17,209)	(357)	(11,865)	(806)	(2,764)	(2,895)		(205)	48%
Total		(75,583)	(41,032)	(668)	(22,792)	(1,316)	(4,238)	(4,551)		(436)	
(108-399) Other Tangible Property		-									AE-ALL
- Demand	DMD-ALL	-	-	-	-	-	-	-		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	-	-	-	-	-	-	-		-	48%
Total		-	-	-	-	-	-	-		-	
Service Company PIS		(30,206,435)									AE-ALL
- Demand	DMD-ALL	(15,640,485)	(9,520,652)	(124,372)	(4,366,974)	(204,170)	(588,765)	(661,830)		(91,953)	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(14,565,949)	(6,877,710)	(142,702)	(4,741,713)	(321,965)	(1,104,763)	(1,157,082)		(82,114)	48%
Total		(30,206,435)	(16,398,362)	(267,074)	(9,108,686)	(526,135)	(1,693,527)	(1,818,912)		(174,067)	
Total Accumulated Depreciation		(645,179,067)									
- Demand		(340,783,788)	(216,179,735)	(2,824,043)	(99,158,249)	(4,635,967)	(13,368,727)	(2,251,022)		(2,087,930)	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		(304,395,278)	(155,470,934)	(3,225,781)	(107,186,617)	(7,278,036)	(24,973,207)	(3,935,481)		(1,856,192)	
Total Accumulated Depreciation		**(645,179,067)**	**(371,650,669)**	**(6,049,825)**	**(206,344,866)**	**(11,914,003)**	**(38,341,934)**	**(6,186,503)**		**(3,944,122)**	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG	Classification Factor
OTHER RATE BASE ITEMS											
Other Rate Base Items											
Materials and Supplies		8,850,642									DISTPLT-PRI
- Demand	DISTPLT-PRI-D	4,692,369	2,998,909	39,176	1,375,553	64,312	185,455	-		28,964	53%
- Customer	DISTPLT-PRI-C	-	-	-	-	-	-	-		-	0%
- Commodity	DISTPLT-PRI-E	4,158,273	2,155,035	44,714	1,485,750	100,883	346,162	-		25,729	47%
Total		8,850,642	5,153,945	83,890	2,861,303	165,195	531,617	-		54,694	
Cash Working Capital		37,799,695									CWC-PRI
- Demand	CWC-PRI-D	20,040,366	12,807,868	167,314	5,874,768	274,664	792,049	-		123,702	53%
- Customer	CWC-PRI-C	-	-	-	-	-	-	-		-	0%
- Commodity	CWC-PRI-E	17,759,329	9,203,815	190,965	6,345,403	430,857	1,478,404	-		109,886	47%
Total		37,799,695	22,011,683	358,279	12,220,171	705,521	2,270,452	-		233,588	
ADIT		(404,577,206)									DISTPLT-PRI
- Demand	DISTPLT-PRI-D	(214,495,786)	(137,085,010)	(1,790,797)	(62,878,741)	(2,939,783)	(8,477,446)	-		(1,324,009)	53%
- Customer	DISTPLT-PRI-C	-	-	-	-	-	-	-		-	0%
- Commodity	DISTPLT-PRI-E	(190,081,420)	(98,510,151)	(2,043,933)	(67,916,038)	(4,611,540)	(15,823,629)	-		(1,176,128)	47%
Total		(404,577,206)	(235,595,161)	(3,834,730)	(130,794,779)	(7,551,323)	(24,301,075)	-		(2,500,137)	
Net /Loss on Reacq Debt		463,605									DISTPLT-PRI
- Demand	DISTPLT-PRI-D	245,791	157,086	2,052	72,053	3,369	9,714	-		1,517	53%
- Customer	DISTPLT-PRI-C	-	-	-	-	-	-	-		-	0%
- Commodity	DISTPLT-PRI-E	217,814	112,883	2,342	77,825	5,284	18,132	-		1,348	47%
Total		463,605	269,969	4,394	149,878	8,653	27,847	-		2,865	
DTA for AMT		3,217,478									DISTPLT-PRI
- Demand	DISTPLT-PRI-D	1,705,819	1,090,195	14,242	500,055	23,379	67,419	-		10,529	53%
- Customer	DISTPLT-PRI-C	-	-	-	-	-	-	-		-	0%
- Commodity	DISTPLT-PRI-E	1,511,659	783,421	16,255	540,115	36,674	125,840	-		9,353	47%
Total		3,217,478	1,873,616	30,496	1,040,171	60,053	193,259	-		19,883	
Net Operating Reserves		(3,161,542)									PAY-PRI
- Demand	PAY-PRI-D	(1,675,259)	(1,070,664)	(13,987)	(491,097)	(22,960)	(66,211)	-		(10,341)	53%
- Customer	PAY-PRI-C	(1,705)	-	-	-	-	-	(1,705)		-	0%
- Commodity	PAY-PRI-E	(1,484,578)	(769,386)	(15,964)	(530,439)	(36,017)	(123,586)	-		(9,186)	47%
Total		(3,161,542)	(1,840,050)	(29,950)	(1,021,536)	(58,977)	(189,797)	(1,705)		(19,527)	
NOL		12,202,176									DISTPLT-PRI
- Demand	DISTPLT-PRI-D	6,469,260	4,134,527	54,011	1,896,443	88,665	255,682	-		39,933	53%
- Customer	DISTPLT-PRI-C	-	-	-	-	-	-	-		-	0%
- Commodity	DISTPLT-PRI-E	5,732,915	2,971,097	61,646	2,048,369	139,086	477,246	-		35,472	47%
Total		12,202,176	7,105,624	115,657	3,944,812	227,750	732,928	-		75,405	
CTA		(325,992)									TOTPLT-PRI
- Demand	TOTPLT-PRI-D	(172,437)	(109,703)	(1,433)	(50,319)	(2,353)	(6,784)	(699)		(1,060)	52.896131%
- Customer	TOTPLT-PRI-C	-	-	-	-	-	-	-		-	0.000000%
- Commodity	TOTPLT-PRI-E	(153,555)	(78,872)	(1,636)	(54,377)	(3,692)	(12,669)	(1,221)		(942)	47.103869%
Total		(325,992)	(188,575)	(3,070)	(104,696)	(6,045)	(19,453)	(1,920)		(2,001)	
Regulatory Asset A&G Capitalization		18,565,864									AE-PRI-GTA&G
- Demand	DMD-PRI	9,823,754	6,278,396	82,017	2,879,801	134,640	388,261	-		60,639	53%
- Customer	CUST-GTA&G	36,516	-	-	-	-	-	36,516		-	0%
- Commodity	NRG-PRI	8,705,593	4,511,695	93,611	3,110,506	211,205	724,711	-		53,866	47%
Total		18,565,864	10,790,090	175,628	5,990,307	345,845	1,112,972	36,516		114,504	
Customer Deposits		-									CUS
- Demand		-	-	-	-	-	-	-		-	0%
- Customer		-	-	-	-	-	-	-		-	100%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		-	-	-	-	-	-	-		-	
Customer Advances		(16,845,133)									DISTPLT-PRI
- Demand	DISTPLT-PRI-D	(8,930,829)	(5,707,724)	(74,562)	(2,618,044)	(122,402)	(352,970)	-		(55,127)	53%
- Customer	DISTPLT-PRI-C	-	-	-	-	-	-	-		-	0%
- Commodity	DISTPLT-PRI-E	(7,914,303)	(4,101,607)	(85,102)	(2,827,778)	(192,008)	(658,839)	-		(48,970)	47%
Total		(16,845,133)	(9,809,331)	(159,664)	(5,445,822)	(314,410)	(1,011,809)	-		(104,097)	
Customer Refunds		(94,007)									DISTPLT-PRI
- Demand	DISTPLT-PRI-D	(49,840)	(31,853)	(416)	(14,610)	(683)	(1,970)	-		(308)	53%
- Customer	DISTPLT-PRI-C	-	-	-	-	-	-	-		-	0%
- Commodity	DISTPLT-PRI-E	(44,167)	(22,890)	(475)	(15,781)	(1,072)	(3,677)	-		(273)	47%
Total		(94,007)	(54,743)	(891)	(30,391)	(1,755)	(5,647)	-		(581)	
Total Other Rate Base Items		(343,904,419)									
- Demand		(182,346,793)	(116,537,974)	(1,522,383)	(53,454,138)	(2,499,153)	(7,206,801)	(699)		(1,125,559)	
- Customer		34,812	-	-	-	-	-	34,812		-	
- Commodity		(161,592,438)	(83,744,960)	(1,737,578)	(57,736,444)	(3,920,340)	(13,451,905)	(1,221)		(999,844)	
Total		(343,904,419)	(200,282,934)	(3,259,961)	(111,190,583)	(6,419,492)	(20,658,706)	32,892		(2,125,404)	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
Rate Base Adjustment											
Adjustment											
AMI		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
Delayed Recognition Pension & OPEB		(12,697,212)									PAY-PRI
- Demand	PAY-PRI-D	(6,728,086)	(4,299,943)	(56,172)	(1,972,316)	(92,212)	(265,912)	-		(41,530)	53%
- Customer	PAY-PRI-C	(6,846)	-	-	-	-	-	(6,846)		-	0%
- Commodity	PAY-PRI-E	(5,962,281)	(3,089,966)	(64,112)	(2,130,321)	(144,650)	(496,340)	-		(36,892)	47%
Total		(12,697,212)	(7,389,910)	(120,284)	(4,102,638)	(236,862)	(762,251)	(6,846)		(78,422)	
Total Rate Base Adjustment		(12,697,212)									
- Demand		(6,728,086)	(4,299,943)	(56,172)	(1,972,316)	(92,212)	(265,912)	-		(41,530)	
- Customer		(6,846)	-	-	-	-	-	(6,846)		-	
- Commodity		(5,962,281)	(3,089,966)	(64,112)	(2,130,321)	(144,650)	(496,340)	-		(36,892)	
Total		(12,697,212)	(7,389,910)	(120,284)	(4,102,638)	(236,862)	(762,251)	(6,846)		(78,422)	
Total Rate Base		**1,047,606,020**									
- Demand		**554,187,624**	**352,646,749**	**4,606,767**	**161,753,525**	**7,562,497**	**21,807,956**	**2,139,788**		**3,405,970**	
- Customer		**27,966**	**-**	**-**	**-**	**-**	**-**	**27,966**		**-**	
- Commodity		**493,390,430**	**253,530,921**	**5,260,374**	**174,792,297**	**11,868,503**	**40,724,527**	**3,741,010**		**3,026,946**	
Total		**1,047,606,020**	**606,177,670**	**9,867,141**	**336,545,821**	**19,431,000**	**62,532,482**	**5,908,765**		**6,432,916**	
OPERATIONS & MAINTENANCE EXPENSES											
Distribution Expenses											
Operations Expenses											
(580) Operation Supervision & Engineering		160,905									AE-PRI
- Demand	DMD-PRI	85,307	54,520	712	25,008	1,169	3,372	-		527	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	75,598	39,179	813	27,011	1,834	6,293	-		468	47%
Total		160,905	93,699	1,525	52,019	3,003	9,665	-		994	
(581) Load Dispatching		1,446,055									AE-PRI
- Demand	DMD-PRI	766,659	489,974	6,401	224,744	10,507	30,300	-		4,732	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	679,396	352,099	7,306	242,748	16,483	56,557	-		4,204	47%
Total		1,446,055	842,073	13,706	467,492	26,990	86,858	-		8,936	
(582) Station Expenses		304,563									AE-PRI
- Demand	DMD-PRI	161,471	103,197	1,348	47,335	2,213	6,382	-		997	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	143,092	74,158	1,539	51,127	3,472	11,912	-		885	47%
Total		304,563	177,354	2,887	98,461	5,685	18,294	-		1,882	
(583) Overhead line expenses		520,027									AE-PRI
- Demand	DMD-PRI	275,704	176,203	2,302	80,822	3,779	10,897	-		1,702	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	244,323	126,621	2,627	87,296	5,927	20,339	-		1,512	47%
Total		520,027	302,824	4,929	168,118	9,706	31,236	-		3,214	
(584) Underground line expenses		1,987,209									AE-PRI
- Demand	DMD-PRI	1,053,564	673,336	8,796	308,849	14,440	41,640	-		6,503	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	933,645	483,864	10,039	333,591	22,651	77,723	-		5,777	47%
Total		1,987,209	1,157,200	18,835	642,440	37,091	119,362	-		12,280	
(585) Street lighting and signal system expenses		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(586) Meter expenses		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(587) Customer installations expenses		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(588) Miscellaneous distribution expenses		10,411,015									DISTPLT-PRI
- Demand	DISTPLT-PRI-D	5,519,636	3,527,619	46,083	1,618,063	75,650	218,151	-		34,071	53%
- Customer	DISTPLT-PRI-C	-	-	-	-	-	-	-		-	0%
- Commodity	DISTPLT-PRI-E	4,891,379	2,534,969	52,597	1,747,688	118,669	407,191	-		30,265	47%
Total		10,411,015	6,062,588	98,679	3,365,752	194,319	625,341	-		64,336	
(589) Rents		1,555,245									AE-PRI
- Demand	DMD-PRI	824,548	526,972	6,884	241,714	11,301	32,588	-		5,090	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	730,697	378,685	7,857	261,078	17,727	60,828	-		4,521	47%
Total		1,555,245	905,657	14,741	502,791	29,028	93,416	-		9,611	
Total Dist. Operations Expenses		16,385,019									
- Demand		8,686,889	5,551,821	72,526	2,546,533	119,059	343,329	-		53,621	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		7,698,129	3,989,574	82,777	2,750,539	186,763	640,843	-		47,632	
Total		16,385,019	9,541,395	155,303	5,297,073	305,822	984,172	-		101,253	
Maintenance Expense											
(590) Maintenance Supervision and Engineering		1,242,451									AE-PRI
- Demand	DMD-PRI	658,713	420,986	5,500	193,100	9,028	26,034	-		4,066	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	583,737	302,523	6,277	208,569	14,162	48,594	-		3,612	47%
Total		1,242,451	723,509	11,776	401,669	23,190	74,628	-		7,678	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
(591) Maintenance of Structures		50,499									AE-PRI
- Demand	DMD-PRI	26,773	17,111	224	7,848	367	1,058	-		165	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	23,726	12,296	255	8,477	576	1,975	-		147	47%
Total		50,499	29,407	479	16,326	943	3,033	-		312	
(592) Maintenance of Station Equipment		5,986,956									AE-PRI
- Demand	DMD-PRI	3,174,121	2,028,592	26,500	930,483	43,503	125,450	-		19,593	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	2,812,835	1,457,759	30,246	1,005,025	68,242	234,159	-		17,404	47%
Total		5,986,956	3,486,350	56,747	1,935,508	111,745	359,609	-		36,997	
(593) Maintenance of Overhead Lines		42,114,302									AE-PRI
- Demand	DMD-PRI	22,327,853	14,269,809	186,412	6,545,337	306,016	882,456	-		137,822	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	19,786,449	10,254,375	212,762	7,069,693	480,036	1,647,154	-		122,429	47%
Total		42,114,302	24,524,184	399,175	13,615,030	786,052	2,529,611	-		260,251	
(594) Maintenance of underground lines		2,286,373									AE-PRI
- Demand	DMD-PRI	1,212,173	774,704	10,120	355,344	16,613	47,908	-		7,482	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	1,074,201	556,707	11,551	383,812	26,061	89,424	-		6,647	47%
Total		2,286,373	1,331,411	21,671	739,156	42,675	137,332	-		14,129	
(595) Maintenance of line transformers		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(596) Maintenance of street lighting and signal systems		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(597) Maintenance of meters		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(598) Maintenance of miscellaneous distribution plant		1,161,127									DISTPLT-PRI
- Demand	DISTPLT-PRI-D	615,598	393,431	5,140	180,461	8,437	24,330	-		3,800	53%
- Customer	DISTPLT-PRI-C	-	-	-	-	-	-	-		-	0%
- Commodity	DISTPLT-PRI-E	545,529	282,722	5,866	194,917	13,235	45,413	-		3,375	47%
Total		1,161,127	676,153	11,006	375,378	21,672	69,744	-		7,175	
Total Dist. Maintenance Expenses		52,841,708									
- Demand		28,015,231	17,904,632	233,895	8,212,574	383,964	1,107,237	-		172,928	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		24,826,478	12,866,381	266,958	8,870,493	602,312	2,066,719	-		153,614	
Total		52,841,708	30,771,014	500,853	17,083,067	986,276	3,173,956	-		326,542	
Total Distribution Expenses		69,226,727									
- Demand		36,702,120	23,456,454	306,421	10,759,107	503,023	1,450,566	-		226,550	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		32,524,607	16,855,955	349,735	11,621,033	789,075	2,707,562	-		201,246	
Total		69,226,727	40,312,409	656,156	22,380,140	1,292,098	4,158,128	-		427,795	
Customer Account Expense											
(901) Supervision		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(902) Meter reading expenses		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(903) Customer records and collection expenses		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(904) Uncollectible accounts		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(905) Miscellaneous customer accounts expenses		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
Total Customer Account Expenses		-									
- Demand		-	-	-	-	-	-	-		-	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		-	-	-	-	-	-	-		-	
Total		-	-	-	-	-	-	-		-	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
Customer Service Expenses											
(907) Customer Service Supervision		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(908) Customer Assistance		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(909) Informational and instructional advertising		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(910) Miscellaneous customer service and informational		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
Total Customer Service Expenses		-									
- Demand		-	-	-	-	-	-	-		-	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		-	-	-	-	-	-	-		-	
Total		-	-	-	-	-	-	-		-	
Sales Expenses											
(911) Sales Exp		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
Total Sales Expenses		-									
- Demand		-	-	-	-	-	-	-		-	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		-	-	-	-	-	-	-		-	
Total		-	-	-	-	-	-	-		-	
Administrative & General Expense											
Labor Related											
(920) Administrative and general salaries		4,748,544									AE-PRI-GTA&G
- Demand	DMD-PRI	2,512,597	1,605,809	20,977	736,560	34,437	99,305	-		15,509	53%
- Customer	CUST-GTA&G	9,340	-	-	-	-	-	9,340		-	0%
- Commodity	NRG-PRI	2,226,608	1,153,945	23,943	795,566	54,019	185,357	-		13,777	47%
Total		4,748,544	2,759,754	44,920	1,532,126	88,456	284,662	9,340		29,287	
(921) Office supplies and expenses		424,763									AE-PRI-GTA&G
- Demand	DMD-PRI	224,755	143,642	1,876	65,886	3,080	8,883	-		1,387	53%
- Customer	CUST-GTA&G	835	-	-	-	-	-	835		-	0%
- Commodity	NRG-PRI	199,173	103,222	2,142	71,164	4,832	16,580	-		1,232	47%
Total		424,763	246,863	4,018	137,050	7,912	25,463	835		2,620	
(922) Administrative expenses transferred—Credit		(422,901)									AE-PRI-GTA&G
- Demand	DMD-PRI	(223,769)	(143,012)	(1,868)	(65,597)	(3,067)	(8,844)	-		(1,381)	53%
- Customer	CUST-GTA&G	(832)	-	-	-	-	-	(832)		-	0%
- Commodity	NRG-PRI	(198,299)	(102,769)	(2,132)	(70,852)	(4,811)	(16,508)	-		(1,227)	47%
Total		(422,901)	(245,781)	(4,001)	(136,450)	(7,878)	(25,352)	(832)		(2,608)	
(923) Outside services employed		15,466,909									AE-PRI-GTA&G
- Demand	DMD-PRI	8,184,004	5,230,426	68,327	2,399,114	112,166	323,454	-		50,517	53%
- Customer	CUST-GTA&G	30,421	-	-	-	-	-	30,421		-	0%
- Commodity	NRG-PRI	7,252,484	3,758,617	77,985	2,591,310	175,952	603,744	-		44,875	47%
Total		15,466,909	8,989,043	146,313	4,990,425	288,118	927,198	30,421		95,392	
(926) Employee pensions and benefits		(954,943)									AE-PRI-GTA&G
- Demand	DMD-PRI	(505,289)	(322,932)	(4,219)	(148,124)	(6,925)	(19,970)	-		(3,119)	53%
- Customer	CUST-GTA&G	(1,878)	-	-	-	-	-	(1,878)		-	0%
- Commodity	NRG-PRI	(447,776)	(232,061)	(4,815)	(159,990)	(10,863)	(37,276)	-		(2,771)	47%
Total		(954,943)	(554,993)	(9,033)	(308,114)	(17,789)	(57,246)	(1,878)		(5,890)	
(426) Pension / OPEB Non-Service Cost		-									AE-PRI-GTA&G
- Demand		-	-	-	-	-	-	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity		-	-	-	-	-	-	-		-	47%
Total		-	-	-	-	-	-	-		-	
(924) Property insurance		92,710									AE-PRI-GTA&G
- Demand	DMD-PRI	49,056	31,352	410	14,380	672	1,939	-		303	53%
- Customer	CUST-GTA&G	182	-	-	-	-	-	182		-	0%
- Commodity	NRG-PRI	43,472	22,529	467	15,533	1,055	3,619	-		269	47%
Total		92,710	53,881	877	29,913	1,727	5,558	182		572	
(925) Injuries and damages		1,693,235									AE-PRI-GTA&G
- Demand	DMD-PRI	895,941	572,599	7,480	262,642	12,279	35,410	-		5,530	53%
- Customer	CUST-GTA&G	3,330	-	-	-	-	-	3,330		-	0%
- Commodity	NRG-PRI	793,963	411,473	8,537	283,683	19,262	66,095	-		4,913	47%
Total		1,693,235	984,073	16,018	546,325	31,542	101,505	3,330		10,443	
(935) Maintenance of general plant		1,514,529									AE-PRI-GTA&G
- Demand	DMD-PRI	801,382	512,166	6,691	234,923	10,983	31,673	-		4,947	53%
- Customer	CUST-GTA&G	2,979	-	-	-	-	-	2,979		-	0%
- Commodity	NRG-PRI	710,167	368,046	7,636	253,743	17,229	59,119	-		4,394	47%
Total		1,514,529	880,212	14,327	488,665	28,213	90,792	2,979		9,341	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
(929) Duplicate charges—Credit		-									AE-PRI-GTA&G
- Demand		-	-	-	-	-	-	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity		-	-	-	-	-	-	-		-	47%
Total		-	-	-	-	-	-	-		-	
(928) Regulatory commission expenses		1,698,261									AE-PRI-GTA&G
- Demand	DMD-PRI	898,601	574,299	7,502	263,422	12,316	35,515	-		5,547	53%
- Customer	CUST-GTA&G	3,340	-	-	-	-	-	3,340		-	0%
- Commodity	NRG-PRI	796,320	412,695	8,563	284,525	19,319	66,291	-		4,927	47%
Total		1,698,261	986,994	16,065	547,947	31,635	101,806	3,340		10,474	
(930.1) Gen Advertising Exp		272,417									AE-PRI-GTA&G
- Demand	DMD-PRI	144,144	92,123	1,203	42,255	1,976	5,697	-		890	53%
- Customer	CUST-GTA&G	536	-	-	-	-	-	536		-	0%
- Commodity	NRG-PRI	127,737	66,200	1,374	45,640	3,099	10,634	-		790	47%
Total		272,417	158,323	2,577	87,896	5,075	16,331	536		1,680	
(930.2) Misc Gen Exp		852,947									AE-PRI-GTA&G
- Demand	DMD-PRI	451,320	288,440	3,768	132,303	6,186	17,837	-		2,786	53%
- Customer	CUST-GTA&G	1,678	-	-	-	-	-	1,678		-	0%
- Commodity	NRG-PRI	399,949	207,275	4,301	142,902	9,703	33,294	-		2,475	47%
Total		852,947	495,715	8,069	275,205	15,889	51,132	1,678		5,261	
(931) Rents		755,211									AE-PRI-GTA&G
- Demand	DMD-PRI	399,604	255,389	3,336	117,143	5,477	15,793	-		2,467	53%
- Customer	CUST-GTA&G	1,485	-	-	-	-	-	1,485		-	0%
- Commodity	NRG-PRI	354,121	183,524	3,808	126,527	8,591	29,479	-		2,191	47%
Total		755,211	438,912	7,144	243,670	14,068	45,273	1,485		4,658	
(932) Institutional Ad - Newspaper		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(933) Transportation expenses		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total A&G Expense		26,141,681									
- Demand		13,832,345	8,840,300	115,484	4,054,907	189,580	546,691	-		85,382	
- Customer		51,417	-	-	-	-	-	51,417		-	
- Commodity		12,257,918	6,352,696	131,809	4,379,751	297,388	1,020,430	-		75,846	
Total		26,141,681	15,192,996	247,293	8,434,658	486,968	1,567,121	51,417		161,228	
O&M Adjustment											
Adjustment											
Int on Cust Deposits		-									CUS
- Demand		-	-	-	-	-	-	-		-	0%
- Customer	CUST-DEP	-	-	-	-	-	-	-		-	100%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		-	-	-	-	-	-	-		-	
Annualize Payroll Increase		1,839,145									PAY-PRI
- Demand	PAY-PRI-D	974,539	622,831	8,136	285,683	13,357	38,516	-		6,015	53%
- Customer	PAY-PRI-C	992	-	-	-	-	-	992		-	0%
- Commodity	PAY-PRI-E	863,615	447,570	9,286	308,569	20,952	71,893	-		5,344	47%
Total		1,839,145	1,070,402	17,423	594,252	34,309	110,409	992		11,359	
Svngs Pln Match on Payroll Inc		55,174									PAY-PRI
- Demand	PAY-PRI-D	29,236	18,685	244	8,570	401	1,155	-		180	53%
- Customer	PAY-PRI-C	30	-	-	-	-	-	30		-	0%
- Commodity	PAY-PRI-E	25,908	13,427	279	9,257	629	2,157	-		160	47%
Total		55,174	32,112	523	17,828	1,029	3,312	30		341	
Reclass Amortization of Net Loss on Reacquired Debt		208,932									DISTPLT-PRI
- Demand	DISTPLT-PRI-D	110,770	70,793	925	32,472	1,518	4,378	-		684	53%
- Customer	DISTPLT-PRI-C	-	-	-	-	-	-	-		-	0%
- Commodity	DISTPLT-PRI-E	98,162	50,873	1,056	35,073	2,381	8,172	-		607	47%
Total		208,932	121,666	1,980	67,545	3,900	12,550	-		1,291	
BPU & RPA Assessments		295,625									DIST-REV
- Demand	DIST-REV-DMD	78,072	-	-	50,448	3,979	9,816	7,295		6,394	26%
- Customer	DIST-REV-CUST	23,804	16,978	518	5,830	49	191	236		-	8%
- Commodity	DIST-REV-NRG	193,750	143,906	2,662	39,305	980	2,524	1,910		2,463	66%
Total		295,625	160,884	3,180	95,582	5,009	12,531	9,441		8,857	
Rate Case Exp		-									AE-ALL
- Demand	DMD-ALL	-	-	-	-	-	-	-		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	-	-	-	-	-	-	-		-	48%
Total		-	-	-	-	-	-	-		-	
Pension Smoothing		5,029,098									PAY-PRI
- Demand	PAY-PRI-D	2,664,853	1,703,117	22,249	781,193	36,523	105,322	-		16,449	53%
- Customer	PAY-PRI-C	2,711	-	-	-	-	-	2,711		-	0%
- Commodity	PAY-PRI-E	2,361,534	1,223,871	25,393	843,775	57,293	196,590	-		14,612	47%
Total		5,029,098	2,926,987	47,642	1,624,968	93,816	301,912	2,711		31,061	
OPEB Smoothing		1,725,691									PAY-PRI
- Demand	PAY-PRI-D	914,421	584,410	7,634	268,060	12,533	36,140	-		5,644	53%
- Customer	PAY-PRI-C	930	-	-	-	-	-	930		-	0%
- Commodity	PAY-PRI-E	810,340	419,960	8,714	289,534	19,660	67,458	-		5,014	47%
Total		1,725,691	1,004,370	16,348	557,594	32,192	103,598	930		10,658	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	Lighting LTG	Classification Factor
Normalize Vegetation Management Expense		4,138,329								OHPLT-PRI
- Demand	OHPLT-PRI-D	2,194,029	1,402,212	18,318	643,172	30,070	86,714	-	13,543	53%
- Customer	OHPLT-PRI-C	-	-	-	-	-	-	-	-	0%
- Commodity	OHPLT-PRI-E	1,944,300	1,007,638	20,907	694,698	47,170	161,856	-	12,030	47%
Total		4,138,329	2,409,850	39,225	1,337,870	77,241	248,570	-	25,573	
ServCo Depr @ JCP&L Rates		614,014								AE-ALL
- Demand	DMD-ALL	317,928	193,529	2,528	88,769	4,150	11,968	13,453	1,869	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	296,086	139,805	2,901	96,386	6,545	22,457	23,520	1,669	48%
Total		614,014	333,334	5,429	185,155	10,695	34,425	36,973	3,538	
SERP/EDCP		1,731,555								PAY-PRI
- Demand	PAY-PRI-D	917,528	586,396	7,660	268,970	12,575	36,263	-	5,664	53%
- Customer	PAY-PRI-C	934	-	-	-	-	-	934	-	0%
- Commodity	PAY-PRI-E	813,093	421,388	8,743	290,518	19,726	67,687	-	5,031	47%
Total		1,731,555	1,007,783	16,403	559,488	32,302	103,950	934	10,695	
Advertising removal		(746,134)								AE-PRI-GTA&G
- Demand	DMD-PRI	(394,802)	(252,319)	(3,296)	(115,735)	(5,411)	(15,604)	-	(2,437)	53%
- Customer	CUST-GTA&G	(1,468)	-	-	-	-	-	(1,468)	-	0%
- Commodity	NRG-PRI	(349,865)	(181,318)	(3,762)	(125,007)	(8,488)	(29,125)	-	(2,165)	47%
Total		(746,134)	(433,638)	(7,058)	(240,742)	(13,899)	(44,729)	(1,468)	(4,602)	
BGS Administrative Labor included in BGS Deferral		(102,860)								AE-ALL
- Demand	DMD-ALL	(53,259)	(32,420)	(424)	(14,871)	(695)	(2,005)	(2,254)	(313)	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	(49,600)	(23,420)	(486)	(16,147)	(1,096)	(3,762)	(3,940)	(280)	48%
Total		(102,860)	(55,840)	(909)	(31,017)	(1,792)	(5,767)	(6,194)	(593)	
Low Income O&M		882,435								AE-ALL
- Demand	DMD-ALL	456,913	278,131	3,633	127,574	5,965	17,200	19,334	2,686	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	425,522	200,922	4,169	138,522	9,406	32,274	33,802	2,399	48%
Total		882,435	479,053	7,802	266,096	15,370	49,474	53,137	5,085	
Contract Labor/Fuel Costs		81,460								AE-PRI-GTA&G
- Demand	DMD-PRI	43,103	27,547	360	12,635	591	1,704	-	266	53%
- Customer	CUST-GTA&G	160	-	-	-	-	-	160	-	0%
- Commodity	NRG-PRI	38,197	19,796	411	13,648	927	3,180	-	236	47%
Total		81,460	47,343	771	26,283	1,517	4,883	160	502	
Total O&M Adjustment		15,752,464								
- Demand		8,253,330	5,202,911	67,968	2,436,941	115,556	331,569	37,828	56,645	
- Customer		28,093	16,978	518	5,830	49	191	4,526	-	
- Commodity		7,471,041	3,884,417	80,272	2,618,132	176,084	603,360	55,293	47,121	
Total		15,752,464	9,104,306	148,757	5,060,903	291,689	935,120	97,647	103,766	
Total O&M Expenses		111,120,872								
- Demand		58,787,795	37,499,665	489,873	17,250,955	808,158	2,328,826	37,828	368,577	
- Customer		79,510	16,978	518	5,830	49	191	55,943	-	
- Commodity		52,253,566	27,093,068	561,815	18,618,915	1,262,547	4,331,352	55,293	324,213	
Total		**111,120,872**	**64,609,711**	**1,052,206**	**35,875,700**	**2,070,755**	**6,660,369**	**149,064**	**692,790**	
DEPRECIATION EXPENSE										
Depreciation Expense										
(403-360) Land & Land Rights		66,658								AE-PRI
- Demand	DMD-PRI	35,340	22,586	295	10,360	484	1,397	-	218	53%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-PRI	31,318	16,230	337	11,190	760	2,607	-	194	47%
Total		66,658	38,816	632	21,550	1,244	4,004	-	412	
(403-361) Struct & Impmnts		526,520								AE-PRI
- Demand	DMD-PRI	279,147	178,404	2,331	81,831	3,826	11,033	-	1,723	53%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-PRI	247,374	128,202	2,660	88,387	6,002	20,593	-	1,531	47%
Total		526,520	306,606	4,991	170,218	9,827	31,626	-	3,254	
(403-362) Station Equip		4,393,098								AE-PRI
- Demand	DMD-PRI	2,329,100	1,488,536	19,445	682,768	31,922	92,052	-	14,377	53%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-PRI	2,063,997	1,069,672	22,194	737,466	50,074	171,821	-	12,771	47%
Total		4,393,098	2,558,208	41,639	1,420,234	81,996	263,873	-	27,148	
(403-364) Poles, Towers & Fixt		9,069,659								AE-PRI
- Demand	DMD-PRI	4,808,486	3,073,120	40,145	1,409,592	65,903	190,044	-	29,681	53%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-PRI	4,261,174	2,208,363	45,820	1,522,516	103,380	354,728	-	26,366	47%
Total		9,069,659	5,281,483	85,966	2,932,108	169,283	544,772	-	56,047	
(403-365) OH Cond & Dev		20,988,905								AE-PRI
- Demand	DMD-PRI	11,127,744	7,111,780	92,904	3,262,062	152,512	439,798	-	68,688	53%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-PRI	9,861,161	5,110,570	106,036	3,523,390	239,240	820,908	-	61,016	47%
Total		20,988,905	12,222,351	198,940	6,785,452	391,752	1,260,706	-	129,704	
(403-366) UG Conduit		990,718								AE-PRI
- Demand	DMD-PRI	525,251	335,690	4,385	153,976	7,199	20,759	-	3,242	53%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-PRI	465,466	241,229	5,005	166,311	11,293	38,748	-	2,880	47%
Total		990,718	576,919	9,390	320,287	18,491	59,508	-	6,122	
(403-367) UG Cond & Dev		6,410,848								AE-PRI
- Demand	DMD-PRI	3,398,856	2,172,221	28,377	996,364	46,583	134,332	-	20,980	53%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-PRI	3,011,991	1,560,972	32,388	1,076,184	73,074	250,738	-	18,637	47%
Total		6,410,848	3,733,193	60,764	2,072,547	119,657	385,070	-	39,617	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	Lighting LTG	Classification Factor
(403-368) Line Transformers		-								#N/A
- Demand		-	-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	-	
(403-369) Services		-								#N/A
- Demand		-	-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	-	
(403-370) Meters		-								#N/A
- Demand		-	-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	-	
(403-371) Install on Cust Premise		-								#N/A
- Demand		-	-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	-	
(403-373) St Lt & Signal Sys		-								#N/A
- Demand		-	-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	-	
(403-374) Asset Ret Costs		-								AE-PRI
- Demand	DMD-PRI	-	-	-	-	-	-	-	-	53%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-PRI	-	-	-	-	-	-	-	-	47%
Total		-	-	-	-	-	-	-	-	
(403-389) Land & Land Rights		143								AE-ALL
- Demand	DMD-ALL	74	45	1	21	1	3	3	0	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	69	33	1	23	2	5	5	0	48%
Total		143	78	1	43	2	8	9	1	
(403-390) Struct & Impmnts -		455,452								AE-ALL
- Demand	DMD-ALL	235,827	143,552	1,875	65,845	3,078	8,877	9,979	1,386	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	219,625	103,702	2,152	71,495	4,855	16,658	17,446	1,238	48%
Total		455,452	247,254	4,027	137,341	7,933	25,535	27,425	2,625	
(403-391) Office Furn & Equip		2,248,029								AE-ALL
- Demand	DMD-ALL	1,163,999	708,548	9,256	325,000	15,195	43,817	49,255	6,843	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	1,084,030	511,854	10,620	352,889	23,961	82,219	86,113	6,111	48%
Total		2,248,029	1,220,402	19,876	677,888	39,156	126,036	135,367	12,954	
(403-392) Transportation Equip		522,042								AE-ALL
- Demand	DMD-ALL	270,306	164,540	2,149	75,472	3,529	10,175	11,438	1,589	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	251,736	118,864	2,466	81,949	5,564	19,093	19,997	1,419	48%
Total		522,042	283,404	4,616	157,421	9,093	29,268	31,435	3,008	
(403-393) Stores Equip		6,830								AE-ALL
- Demand	DMD-ALL	3,536	2,153	28	987	46	133	150	21	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	3,293	1,555	32	1,072	73	250	262	19	48%
Total		6,830	3,708	60	2,060	119	383	411	39	
(403-394) Tools, Shop & Garage Equip		313,574								AE-ALL
- Demand	DMD-ALL	162,364	98,834	1,291	45,334	2,119	6,112	6,870	955	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	151,210	71,398	1,481	49,224	3,342	11,469	12,012	852	48%
Total		313,574	170,232	2,773	94,558	5,462	17,581	18,882	1,807	
(403-395) Laboratory Equip		6,433								AE-ALL
- Demand	DMD-ALL	3,331	2,028	26	930	43	125	141	20	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	3,102	1,465	30	1,010	69	235	246	17	48%
Total		6,433	3,492	57	1,940	112	361	387	37	
(403-396) Power Operated Equip		19,617								AE-ALL
- Demand	DMD-ALL	10,158	6,183	81	2,836	133	382	430	60	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	9,460	4,467	93	3,079	209	717	751	53	48%
Total		19,617	10,650	173	5,916	342	1,100	1,181	113	
(403-397) Communication Equip		1,110,157								AE-ALL
- Demand	DMD-ALL	574,824	349,906	4,571	160,496	7,504	21,638	24,324	3,380	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	535,333	252,772	5,245	174,269	11,833	40,603	42,525	3,018	48%
Total		1,110,157	602,678	9,816	334,765	19,337	62,241	66,849	6,397	
(403-398) MISC Equip		(5,809)								AE-ALL
- Demand	DMD-ALL	(3,008)	(1,831)	(24)	(840)	(39)	(113)	(127)	(18)	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	(2,801)	(1,323)	(27)	(912)	(62)	(212)	(223)	(16)	48%
Total		(5,809)	(3,154)	(51)	(1,752)	(101)	(326)	(350)	(33)	
Total Depreciation Expense		47,122,873								
- Demand		24,925,337	15,856,296	207,137	7,273,034	340,038	980,566	102,462	153,145	
- Customer		-	-	-	-	-	-	-	-	
- Commodity		22,197,536	11,400,024	236,533	7,859,540	533,668	1,831,179	179,136	136,107	
Total		47,122,873	27,256,320	443,670	15,132,574	873,705	2,811,745	281,598	289,252	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	Lighting LTG	Classification Factor
Depreciation Adjustment										
Adjustment										
Annualize Deprec Exp		3,142,011								DPR-TOT-PRI
- Demand	DPR-TOT-PRI-D	1,661,946	1,057,250	13,811	484,944	22,673	65,381	6,832	10,211	53%
- Customer	DPR-TOT-PRI-C	-	-	-	-	-	-	-	-	0%
- Commodity	DPR-TOT-PRI-E	1,480,065	760,119	15,771	524,050	35,583	122,098	11,944	9,075	47%
Total		3,142,011	1,817,369	29,583	1,008,994	58,256	187,479	18,776	19,286	
Average Net Salvage		1,452,920								DISTPLT-PRI
- Demand	DISTPLT-PRI-D	770,298	492,300	6,431	225,810	10,557	30,444	-	4,755	53%
- Customer	DISTPLT-PRI-C	-	-	-	-	-	-	-	-	0%
- Commodity	DISTPLT-PRI-E	682,621	353,770	7,340	243,900	16,561	56,826	-	4,224	47%
Total		1,452,920	846,071	13,771	469,711	27,118	87,270	-	8,979	
Total Depreciation Adjustment		4,594,931								
- Demand		2,432,245	1,549,550	20,242	710,754	33,230	95,825	6,832	14,966	
- Customer		-	-	-	-	-	-	-	-	
- Commodity		2,162,686	1,113,889	23,111	767,951	52,144	178,923	11,944	13,299	
Total		4,594,931	2,663,440	43,354	1,478,705	85,374	274,749	18,776	28,265	
Total Depreciation Expense										
- Demand		27,357,582	17,405,846	227,380	7,983,788	373,268	1,076,391	109,294	168,111	
- Customer		-	-	-	-	-	-	-	-	
- Commodity		24,360,222	12,513,914	259,644	8,627,491	585,812	2,010,103	191,080	149,406	
Total		**51,717,804**	**29,919,760**	**487,024**	**16,611,279**	**959,080**	**3,086,494**	**300,374**	**317,517**	
Amortization, Accretion, Regulatory Debits and Credits										
Amort - Ltd Term Elec Prpty		4,209,061								DISTPLT-PRI
- Demand	DISTPLT-PRI-D	2,231,529	1,426,178	18,631	654,166	30,584	88,196	-	13,774	53%
- Customer	DISTPLT-PRI-C	-	-	-	-	-	-	-	-	0%
- Commodity	DISTPLT-PRI-E	1,977,532	1,024,861	21,264	706,572	47,977	164,623	-	12,236	47%
Total		4,209,061	2,451,039	39,895	1,360,737	78,561	252,819	-	26,010	
Accretion Expense		136,563								AE-ALL
- Demand	DMD-ALL	70,711	43,043	562	19,743	923	2,662	2,992	416	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	65,853	31,094	645	21,437	1,456	4,995	5,231	371	48%
Total		136,563	74,137	1,207	41,180	2,379	7,656	8,223	787	
Regulatory Debits		22,140,546								AE-ALL
- Demand	DMD-ALL	11,464,077	6,978,395	91,162	3,200,880	149,651	431,550	485,104	67,399	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	10,676,469	5,041,186	104,597	3,475,554	235,992	809,763	848,112	60,188	48%
Total		22,140,546	12,019,581	195,758	6,676,435	385,644	1,241,312	1,333,216	127,587	
Regulatory Credits		9,222								AE-ALL
- Demand	DMD-ALL	4,775	2,907	38	1,333	62	180	202	28	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	4,447	2,100	44	1,448	98	337	353	25	48%
Total		9,222	5,006	82	2,781	161	517	555	53	
Total Depreciation and Amortization		78,213,196								
- Demand		41,128,674	25,856,369	337,772	11,859,910	554,489	1,598,978	597,593	249,729	
- Customer		-	-	-	-	-	-	-	-	
- Commodity		37,084,523	18,613,154	386,194	12,832,502	871,335	2,989,820	1,044,776	222,225	
Total		**78,213,196**	**44,469,523**	**723,966**	**24,692,412**	**1,425,824**	**4,588,799**	**1,642,369**	**471,954**	
TAXES										
Taxes Other than Income										
(408) Payroll Taxes		1,247,629								PAY-PRI
- Demand	PAY-PRI-D	661,102	422,513	5,519	193,800	9,061	26,129	-	4,081	53%
- Customer	PAY-PRI-C	673	-	-	-	-	-	673	-	0%
- Commodity	PAY-PRI-E	585,854	303,620	6,300	209,326	14,213	48,770	-	3,625	47%
Total		1,247,629	726,133	11,819	403,126	23,274	74,899	673	7,706	
(408) Property Taxes		1,817,787								RB-PRI
- Demand	RB-PRI-D	961,616	611,906	7,994	280,672	13,122	37,841	3,713	5,910	53%
- Customer	RB-PRI-C	49	-	-	-	-	-	49	-	0%
- Commodity	RB-PRI-E	856,122	439,922	9,128	303,296	20,594	70,664	6,491	5,252	47%
Total		1,817,787	1,051,828	17,121	583,968	33,716	108,505	10,253	11,162	
Total Taxes Other than Income		3,065,416								
- Demand		1,622,719	1,034,419	13,513	474,472	22,183	63,969	3,713	9,991	
- Customer		721	-	-	-	-	-	721	-	
- Commodity		1,441,976	743,543	15,427	512,622	34,807	119,435	6,491	8,877	
Total Taxes Other than Income		**3,065,416**	**1,777,962**	**28,940**	**987,094**	**56,990**	**183,404**	**10,925**	**18,868**	
Total Expenses		**192,399,484**								
- Demand		**101,539,188**	**64,390,454**	**841,159**	**29,585,337**	**1,384,830**	**3,991,773**	**639,134**	**628,296**	
- Customer		**80,232**	**16,978**	**518**	**5,830**	**49**	**191**	**56,664**	**-**	
- Commodity		**90,780,065**	**46,449,765**	**963,437**	**31,964,039**	**2,168,689**	**7,440,607**	**1,106,560**	**555,316**	
Total		**192,399,484**	**110,857,196**	**1,805,113**	**61,555,206**	**3,553,569**	**11,432,572**	**1,802,358**	**1,183,612**	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Primary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
REVENUE REQUIREMENT CALCULATION											
Total Rate Base											
- Demand		554,187,624	352,646,749	4,606,767	161,753,525	7,562,497	21,807,956	2,139,788		3,405,970	
- Customer		27,966	-	-	-	-	-	27,966		-	
- Commodity		493,390,430	253,530,921	5,260,374	174,792,297	11,868,503	40,724,527	3,741,010		3,026,946	
Total		1,047,606,020	606,177,670	9,867,141	336,545,821	19,431,000	62,532,482	5,908,765		6,432,916	
Required Net Income											
- Demand		42,118,259	26,801,153	350,114	12,293,268	574,750	1,657,405	162,624		258,854	
- Customer		2,125	-	-	-	-	-	2,125		-	
- Commodity		37,497,673	19,268,350	399,788	13,284,215	902,006	3,095,064	284,317		230,048	
Total		79,618,058	46,069,503	749,903	25,577,482	1,476,756	4,752,469	449,066		488,902	
Interest Synchronization											
- Demand		12,187,317	7,755,167	101,309	3,557,173	166,309	479,586	47,057		74,902	
- Customer		615	-	-	-	-	-	615		-	
- Commodity		10,850,307	5,575,480	115,683	3,843,913	261,004	895,586	82,270		66,567	
Total		23,038,239	13,330,647	216,991	7,401,087	427,313	1,375,172	129,942		141,468	
Net Income Before Income Taxes											
- Demand		29,930,942	19,045,985	248,805	8,736,094	408,440	1,177,819	115,567		183,952	
- Customer		1,510	-	-	-	-	-	1,510		-	
- Commodity		26,647,366	13,692,870	284,106	9,440,301	641,002	2,199,478	202,047		163,481	
Total		56,579,818	32,738,856	532,911	18,176,396	1,049,443	3,377,297	319,125		347,433	
Taxable Income											
- Demand		41,634,361	26,493,233	346,092	12,152,030	568,146	1,638,363	160,756		255,880	
- Customer		2,101	-	-	-	-	-	2,101		-	
- Commodity		37,066,860	19,046,975	395,195	13,131,592	891,643	3,059,505	281,050		227,405	
Total		78,703,322	45,540,209	741,287	25,283,622	1,459,789	4,697,867	443,907		483,285	
NJ State Corporate Business Tax											
- Demand		3,747,092	2,384,391	31,148	1,093,683	51,133	147,453	14,468		23,029	
- Customer		189	-	-	-	-	-	189		-	
- Commodity		3,336,017	1,714,228	35,568	1,181,843	80,248	275,355	25,295		20,466	
Total		7,083,299	4,098,619	66,716	2,275,526	131,381	422,808	39,952		43,496	
Federal Taxable Income											
- Demand		37,887,269	24,108,842	314,944	11,058,347	517,013	1,490,910	146,288		232,851	
- Customer		1,912	-	-	-	-	-	1,912		-	
- Commodity		33,730,843	17,332,747	359,628	11,949,748	811,395	2,784,149	255,756		206,938	
Total		71,620,023	41,441,590	674,571	23,008,096	1,328,408	4,275,059	403,955		439,789	
Federal Income Tax											
- Demand		7,956,326	5,062,857	66,138	2,322,253	108,573	313,091	30,720		48,899	
- Customer		402	-	-	-	-	-	402		-	
- Commodity		7,083,477	3,639,877	75,522	2,509,447	170,393	584,671	53,709		43,457	
Total		15,040,205	8,702,734	141,660	4,831,700	278,966	897,762	84,831		92,356	
NJ Federal & State Income Tax		22,123,504									
- Demand		11,703,419	7,447,248	97,286	3,415,936	159,706	460,544	45,188		71,928	
- Customer		591	-	-	-	-	-	591		-	
- Commodity		10,419,494	5,354,105	111,089	3,691,290	250,641	860,027	79,003		63,923	
Total		22,123,504	12,801,353	208,376	7,107,226	410,347	1,320,571	124,782		135,851	
Tax Reform Amortization		(3,245,508)									RB-PRI
- Demand	RB-PRI-D	(1,716,886)	(1,092,508)	(14,272)	(501,116)	(23,429)	(67,562)	(6,629)		(10,552)	53%
- Customer	RB-PRI-C	(87)	-	-	-	-	-	(87)		-	0%
- Commodity	RB-PRI-E	(1,528,535)	(785,445)	(16,297)	(541,511)	(36,769)	(126,166)	(11,590)		(9,378)	47%
Total		(3,245,508)	(1,877,953)	(30,569)	(1,042,627)	(60,198)	(193,727)	(18,305)		(19,929)	
Investment Tax Credit		(47,332)									RB-PRI
- Demand	RB-PRI-D	(25,039)	(15,933)	(208)	(7,308)	(342)	(985)	(97)		(154)	53%
- Customer	RB-PRI-C	(1)	-	-	-	-	-	(1)		-	0%
- Commodity	RB-PRI-E	(22,292)	(11,455)	(238)	(7,897)	(536)	(1,840)	(169)		(137)	47%
Total		(47,332)	(27,388)	(446)	(15,205)	(878)	(2,825)	(267)		(291)	
Federal & State Income Taxes											
- Demand		9,961,494	6,338,807	82,806	2,907,511	135,935	391,997	38,463		61,222	
- Customer		503	-	-	-	-	-	503		-	
- Commodity		8,868,667	4,557,205	94,555	3,141,882	213,336	732,021	67,244		54,409	
Total		18,830,664	10,896,012	177,361	6,049,394	349,271	1,124,018	106,210		115,631	
Revenue Requirement											
- Demand		**153,618,941**	**97,530,414**	**1,274,079**	**44,786,116**	**2,095,516**	**6,041,175**	**840,221**		**948,372**	
- Customer		**82,860**	**16,978**	**518**	**5,830**	**49**	**191**	**59,292**		**-**	
- Commodity		**137,146,405**	**70,275,320**	**1,457,780**	**48,390,136**	**3,284,031**	**11,267,693**	**1,458,121**		**839,773**	
Total		**290,848,206**	**167,822,712**	**2,732,377**	**93,182,082**	**5,379,596**	**17,309,059**	**2,357,634**		**1,788,145**	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG	Classification Factor
UTILITY PLANT											
Intangible Plant											
(301) Organizational Costs		29,589									AE-ALL
- Demand	DMD-ALL	15,321	9,326	122	4,278	200	577	648		90	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	14,268	6,737	140	4,645	315	1,082	1,133		80	48%
Total		29,589	16,063	262	8,922	515	1,659	1,782		171	
(302) Franchises & Consents		1,571									AE-ALL
- Demand	DMD-ALL	814	495	6	227	11	31	34		5	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	758	358	7	247	17	57	60		4	48%
Total		1,571	853	14	474	27	88	95		9	
(303) Misc. Intangible Plant		104,471,528									AE-ALL
- Demand	DMD-ALL	54,093,951	32,927,988	430,152	15,103,551	706,140	2,036,293	2,288,994		318,029	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	50,377,576	23,787,146	493,546	16,399,617	1,113,544	3,820,916	4,001,867		283,998	48%
Total		104,471,528	56,715,134	923,698	31,503,167	1,819,683	5,857,209	6,290,861		602,027	
Total Intangible Plant		104,502,688									
- Demand		54,110,086	32,937,809	430,280	15,108,055	706,350	2,036,900	2,289,677		318,123	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		50,392,602	23,794,241	493,694	16,404,508	1,113,876	3,822,055	4,003,061		284,083	
Total		104,502,688	56,732,050	923,974	31,512,564	1,820,226	5,858,956	6,292,737		602,207	
Distribution Plant											
(360) Land and Land Rights		16,328,813									AE-SEC
- Demand	DMD-SEC	8,889,267	5,914,936	77,269	2,713,088	126,846	-	-		57,128	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	7,439,547	4,205,671	87,261	2,899,523	196,879	-	-		50,212	46%
Total		16,328,813	10,120,606	164,530	5,612,611	323,725	-	-		107,340	
(361) Structures and Improvements		45,700,085									AE-SEC
- Demand	DMD-SEC	24,878,737	16,554,361	216,256	7,593,225	355,008	-	-		159,887	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	20,821,348	11,770,573	244,221	8,115,008	551,014	-	-		140,531	46%
Total		45,700,085	28,324,934	460,477	15,708,234	906,022	-	-		300,418	
(362) Station Equipment		294,950,319									AE-SEC
- Demand	DMD-SEC	160,568,441	106,842,558	1,395,728	49,007,003	2,291,235	-	-		1,031,918	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	134,381,878	75,967,789	1,576,214	52,374,615	3,556,268	-	-		906,991	46%
Total		294,950,319	182,810,347	2,971,942	101,381,618	5,847,503	-	-		1,938,909	
(364) Poles, Towers & Fixtures		395,829,391									AE-SEC
- Demand	DMD-SEC	215,486,148	143,384,909	1,873,095	65,768,405	3,074,884	-	-		1,384,855	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	180,343,243	101,950,335	2,115,312	70,287,810	4,772,585	-	-		1,217,201	46%
Total		395,829,391	245,335,243	3,988,407	136,056,215	7,847,469	-	-		2,602,056	
(365) Overhead Conductors & Devices		636,490,202									AE-SEC
- Demand	DMD-SEC	346,499,844	230,561,680	3,011,920	105,755,021	4,944,387	-	-		2,226,835	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	289,990,358	163,935,247	3,401,403	113,022,184	7,674,275	-	-		1,957,249	46%
Total		636,490,202	394,496,928	6,413,323	218,777,205	12,618,662	-	-		4,184,084	
(366) Underground Conduit		12,435,921									AE-SEC
- Demand	DMD-SEC	6,770,009	4,504,778	58,848	2,066,271	96,605	-	-		43,509	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	5,665,911	3,203,012	66,458	2,208,259	149,942	-	-		38,241	46%
Total		12,435,921	7,707,789	125,305	4,274,529	246,547	-	-		81,750	
(367) Underground Conductors & Device		347,686,952									AE-SEC
- Demand	DMD-SEC	189,277,815	125,945,832	1,645,281	57,769,375	2,700,904	-	-		1,216,423	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	158,409,137	89,550,705	1,858,039	61,739,110	4,192,123	-	-		1,069,160	46%
Total		347,686,952	215,496,537	3,503,320	119,508,485	6,893,027	-	-		2,285,583	
(368) Line Transformers		909,589,450									AE-SEC
- Demand	DMD-SEC	495,172,748	329,488,924	4,304,247	151,131,394	7,065,878	-	-		3,182,305	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	414,416,702	234,275,046	4,860,845	161,516,683	10,967,081	-	-		2,797,047	46%
Total		909,589,450	563,763,971	9,165,092	312,648,077	18,032,959	-	-		5,979,351	
(369) Services		483,989,081									SRVC
- Demand	DMD-SEC	740,996	493,060	6,441	226,159	10,574	-	-		4,762	0%
- Customer	CUST-SVCS	483,248,085	422,629,904	5,981,504	54,557,746	78,931	-	-		-	100%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		483,989,081	423,122,965	5,987,945	54,783,905	89,504	-	-		4,762	
(370) Meters		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(371) Installation on Customers' Premises		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(373) Street Lighting & Signal Systems		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
(374) Asset Retirement Costs		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(375) Charging Stations		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
Total Distribution Plant		3,143,000,214									
- Demand		1,448,284,005	963,691,037	12,589,086	442,029,941	20,666,320	-	-		9,307,622	
- Customer		483,248,085	422,629,904	5,981,504	54,557,746	78,931	-	-		-	
- Commodity		1,211,468,124	684,858,379	14,209,752	472,163,193	32,060,168	-	-		8,176,632	
Total		3,143,000,214	2,071,179,320	32,780,342	968,750,880	52,805,418	-	-		17,484,254	
General Plant											
(389) Land and Land Rights		539,031									AE-ALL
- Demand	DMD-ALL	279,103	169,895	2,219	77,928	3,643	10,506	11,810		1,641	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	259,928	122,732	2,546	84,615	5,745	19,714	20,648		1,465	48%
Total		539,031	292,627	4,766	162,544	9,389	30,221	32,458		3,106	
(390) Structures and Improvements		38,105,421									AE-ALL
- Demand	DMD-ALL	19,730,474	12,010,304	156,895	5,508,938	257,561	742,727	834,898		115,999	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	18,374,947	8,676,232	180,018	5,981,671	406,159	1,393,658	1,459,659		103,587	48%
Total		38,105,421	20,686,536	336,914	11,490,609	663,720	2,136,385	2,294,557		219,586	
(391) Office Furniture & Equipment		12,930,053									AE-ALL
- Demand	DMD-ALL	6,695,008	4,075,375	53,238	1,869,310	87,396	252,024	283,300		39,361	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	6,235,046	2,944,047	61,084	2,029,720	137,819	472,901	495,296		35,149	48%
Total		12,930,053	7,019,422	114,323	3,899,030	225,215	724,925	778,597		74,511	
(392) Transportation Equipment		6,278,504									AE-ALL
- Demand	DMD-ALL	3,250,925	1,978,898	25,851	907,689	42,437	122,377	137,563		19,113	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	3,027,579	1,429,554	29,661	985,580	66,921	229,628	240,503		17,068	48%
Total		6,278,504	3,408,452	55,512	1,893,270	109,359	352,005	378,067		36,180	
(393) Stores Equipment		403,584									AE-ALL
- Demand	DMD-ALL	208,970	127,204	1,662	58,347	2,728	7,866	8,843		1,229	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	194,614	91,892	1,907	63,353	4,302	14,761	15,460		1,097	48%
Total		403,584	219,096	3,568	121,700	7,030	22,627	24,302		2,326	
(394) Tools, Shop & Garage Equipment		8,699,117									AE-ALL
- Demand	DMD-ALL	4,504,285	2,741,842	35,818	1,257,640	58,799	169,558	190,600		26,482	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	4,194,831	1,980,704	41,097	1,365,560	92,722	318,159	333,227		23,648	48%
Total		8,699,117	4,722,546	76,914	2,623,200	151,521	487,717	523,826		50,129	
(395) Laboratory Equipment		153,834									AE-ALL
- Demand	DMD-ALL	79,653	48,486	633	22,240	1,040	2,998	3,371		468	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	74,181	35,027	727	24,148	1,640	5,626	5,893		418	48%
Total		153,834	83,513	1,360	46,388	2,679	8,625	9,263		886	
(396) Power Operated Equipment		737,856									AE-ALL
- Demand	DMD-ALL	382,052	232,562	3,038	106,673	4,987	14,382	16,167		2,246	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	355,804	168,003	3,486	115,826	7,865	26,986	28,264		2,006	48%
Total		737,856	400,565	6,524	222,499	12,852	41,368	44,431		4,252	
(397) Communication Equipment		23,471,643									AE-ALL
- Demand	DMD-ALL	12,153,301	7,397,939	96,642	3,393,318	158,649	457,494	514,269		71,452	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	11,318,342	5,344,264	110,885	3,684,506	250,180	858,446	899,100		63,806	48%
Total		23,471,643	12,742,202	207,527	7,077,824	408,829	1,315,940	1,413,369		135,258	
(398) Misc. Equipment		63,255									AE-ALL
- Demand	DMD-ALL	32,753	19,937	260	9,145	428	1,233	1,386		193	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	30,503	14,403	299	9,930	674	2,313	2,423		172	48%
Total		63,255	34,340	559	19,075	1,102	3,546	3,809		365	
(399) Other Tangible Property		525,965									AE-ALL
- Demand	DMD-ALL	272,338	165,777	2,166	76,039	3,555	10,252	11,524		1,601	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	253,627	119,757	2,485	82,564	5,606	19,237	20,148		1,430	48%
Total		525,965	285,534	4,650	158,604	9,161	29,488	31,672		3,031	
(SRVCO-PIS) Service Company PIS		50,299,237									AE-ALL
- Demand	DMD-ALL	26,044,268	15,853,627	207,102	7,271,810	339,980	980,401	1,102,067		153,119	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	24,254,969	11,452,645	237,625	7,895,818	536,131	1,839,632	1,926,753		136,735	48%
Total		50,299,237	27,306,272	444,727	15,167,628	876,111	2,820,033	3,028,820		289,854	
Total General Plant		142,207,500									
- Demand		73,633,130	44,821,847	585,526	20,559,077	961,203	2,771,819	3,115,797		432,903	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		68,574,370	32,379,259	671,820	22,323,293	1,515,765	5,201,062	5,447,374		386,581	
Total		142,207,500	77,201,105	1,257,345	42,882,370	2,476,968	7,972,880	8,563,171		819,484	
Total Utility Plant		3,389,710,401									
- Demand		1,576,027,221	1,041,450,692	13,604,891	477,697,074	22,333,873	4,808,719	5,405,474		10,058,649	
- Customer		483,248,085	422,629,904	5,981,504	54,557,746	78,931	-	-		-	
- Commodity		1,330,435,095	741,031,879	15,375,265	510,890,994	34,689,809	9,023,117	9,450,435		8,847,296	
Total		3,389,710,401	2,205,112,475	34,961,661	1,043,145,813	57,102,612	13,831,836	14,855,909		18,905,945	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
Additions to Utility Plant											
Construction Work in Progress		-									
- Demand		-	-	-	-	-	-	-		-	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		-	-	-	-	-	-	-		-	
Total		-	-	-	-	-	-	-		-	
Total Additional to Utility Plant		-									
- Demand		-	-	-	-	-	-	-		-	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		-	-	-	-	-	-	-		-	
Total		-	-	-	-	-	-	-		-	
Total Utility Plant		3,389,710,401									
- Demand		1,576,027,221	1,041,450,692	13,604,891	477,697,074	22,333,873	4,808,719	5,405,474		10,058,649	
- Customer		483,248,085	422,629,904	5,981,504	54,557,746	78,931	-	-		-	
- Commodity		1,330,435,095	741,031,879	15,375,265	510,890,994	34,689,809	9,023,117	9,450,435		8,847,296	
Total		**3,389,710,401**	**2,205,112,475**	**34,961,661**	**1,043,145,813**	**57,102,612**	**13,831,836**	**14,855,909**		**18,905,945**	
ACCUMULATED DEPRECIATION											
Accumulated Depreciation											
(108-303) Misc Intangible Plant		(65,064,960)									AE-ALL
- Demand	DMD-ALL	(33,689,761)	(20,507,580)	(267,899)	(9,406,505)	(439,784)	(1,268,205)	(1,425,587)		(198,068)	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(31,375,199)	(14,814,656)	(307,381)	(10,213,696)	(693,516)	(2,379,670)	(2,492,366)		(176,875)	48%
Total		(65,064,960)	(35,322,235)	(575,280)	(19,620,200)	(1,133,300)	(3,647,875)	(3,917,954)		(374,943)	
(108-360) Land & Land Rights		(9,226,037)									AE-SEC
- Demand	DMD-SEC	(5,022,576)	(3,342,032)	(43,658)	(1,532,938)	(71,670)	-	-		(32,278)	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	(4,203,461)	(2,376,270)	(49,304)	(1,638,276)	(111,240)	-	-		(28,371)	46%
Total		(9,226,037)	(5,718,302)	(92,962)	(3,171,214)	(182,910)	-	-		(60,649)	
(108-361) Struct & Impmnts		(8,588,758)									AE-SEC
- Demand	DMD-SEC	(4,675,647)	(3,111,185)	(40,643)	(1,427,052)	(66,719)	-	-		(30,049)	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	(3,913,111)	(2,212,132)	(45,898)	(1,525,114)	(103,556)	-	-		(26,411)	46%
Total		(8,588,758)	(5,323,316)	(86,541)	(2,952,166)	(170,275)	-	-		(56,460)	
(108-362) Station Equip		(102,333,669)									AE-SEC
- Demand	DMD-SEC	(55,709,578)	(37,069,263)	(484,251)	(17,003,089)	(794,949)	-	-		(358,026)	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	(46,624,091)	(26,357,193)	(546,871)	(18,171,489)	(1,233,855)	-	-		(314,683)	46%
Total		(102,333,669)	(63,426,456)	(1,031,122)	(35,174,578)	(2,028,804)	-	-		(672,709)	
(108-364) Poles, Towers & Fixt		(151,290,456)									AE-SEC
- Demand	DMD-SEC	(82,361,235)	(54,803,329)	(715,918)	(25,137,426)	(1,175,255)	-	-		(529,307)	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	(68,929,220)	(38,966,567)	(808,496)	(26,864,793)	(1,824,136)	-	-		(465,228)	46%
Total		(151,290,456)	(93,769,896)	(1,524,414)	(52,002,219)	(2,999,391)	-	-		(994,535)	
(108-365) OH Cond & Dev		(97,687,661)									AE-SEC
- Demand	DMD-SEC	(53,180,330)	(35,386,297)	(462,265)	(16,231,139)	(758,858)	-	-		(341,772)	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	(44,507,330)	(25,160,561)	(522,043)	(17,346,493)	(1,177,837)	-	-		(300,396)	46%
Total		(97,687,661)	(60,546,858)	(984,308)	(33,577,631)	(1,936,695)	-	-		(642,168)	
(108-366) UG Conduit		(6,202,112)									AE-SEC
- Demand	DMD-SEC	(3,376,377)	(2,246,648)	(29,349)	(1,030,502)	(48,179)	-	-		(21,699)	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	(2,825,735)	(1,597,424)	(33,144)	(1,101,315)	(74,780)	-	-		(19,072)	46%
Total		(6,202,112)	(3,844,072)	(62,493)	(2,131,817)	(122,959)	-	-		(40,771)	
(108-367) UG Cond & Dev		(117,495,009)									AE-SEC
- Demand	DMD-SEC	(63,963,282)	(42,561,294)	(555,995)	(19,522,197)	(912,725)	-	-		(411,070)	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	(53,531,727)	(30,262,168)	(627,893)	(20,863,703)	(1,416,658)	-	-		(361,305)	46%
Total		(117,495,009)	(72,823,462)	(1,183,889)	(40,385,900)	(2,329,384)	-	-		(772,375)	
(108-368) Line Transformers		(315,307,756)									AE-SEC
- Demand	DMD-SEC	(171,650,856)	(114,216,819)	(1,492,060)	(52,389,461)	(2,449,376)	-	-		(1,103,141)	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	(143,656,900)	(81,211,077)	(1,685,004)	(55,989,505)	(3,801,721)	-	-		(969,592)	46%
Total		(315,307,756)	(195,427,896)	(3,177,065)	(108,378,966)	(6,251,097)	-	-		(2,072,733)	
(108-369) Services		(191,180,068)									SRVC
- Demand	DMD-SEC	(292,700)	(194,763)	(2,544)	(89,335)	(4,177)	-	-		(1,881)	0%
- Customer	CUST-SVCS	(190,887,368)	(166,942,638)	(2,362,748)	(21,550,804)	(31,178)	-	-		-	100%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		(191,180,068)	(167,137,401)	(2,365,293)	(21,640,138)	(35,355)	-	-		(1,881)	
(108-370) Meters		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(108-371) Install on Cust Premise		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(108-373) St Lt & Signal Sys		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
(108-374) Asset Ret Costs		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(108-389) Land & Land Rights		(4,140)									AE-ALL
- Demand	DMD-ALL	(2,143)	(1,305)	(17)	(598)	(28)	(81)	(91)		(13)	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(1,996)	(943)	(20)	(650)	(44)	(151)	(159)		(11)	48%
Total		(4,140)	(2,247)	(37)	(1,248)	(72)	(232)	(249)		(24)	
(108-390) Struct & Impmnts -		(33,630,647)									AE-ALL
- Demand	DMD-ALL	(17,413,496)	(10,599,917)	(138,471)	(4,862,015)	(227,315)	(655,507)	(736,855)		(102,377)	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(16,217,150)	(7,657,370)	(158,879)	(5,279,235)	(358,463)	(1,229,999)	(1,288,249)		(91,423)	48%
Total		(33,630,647)	(18,257,287)	(297,350)	(10,141,250)	(585,778)	(1,885,506)	(2,025,104)		(193,800)	
(108-391) Office Furn & Equip		(3,754,727)									AE-ALL
- Demand	DMD-ALL	(1,944,147)	(1,183,438)	(15,460)	(542,824)	(25,379)	(73,185)	(82,267)		(11,430)	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(1,810,580)	(854,915)	(17,738)	(589,405)	(40,021)	(137,324)	(143,828)		(10,207)	48%
Total		(3,754,727)	(2,038,353)	(33,198)	(1,132,230)	(65,400)	(210,509)	(226,095)		(21,637)	
(108-392) Transportation Equip		(3,097,257)									AE-ALL
- Demand	DMD-ALL	(1,603,718)	(976,213)	(12,753)	(447,773)	(20,935)	(60,370)	(67,862)		(9,429)	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(1,493,539)	(705,215)	(14,632)	(486,198)	(33,013)	(113,278)	(118,643)		(8,420)	48%
Total		(3,097,257)	(1,681,428)	(27,385)	(933,971)	(53,948)	(173,648)	(186,505)		(17,848)	
(108-393) Stores Equip		(573,955)									AE-ALL
- Demand	DMD-ALL	(297,186)	(180,903)	(2,363)	(82,977)	(3,879)	(11,187)	(12,575)		(1,747)	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(276,769)	(130,684)	(2,711)	(90,098)	(6,118)	(20,992)	(21,986)		(1,560)	48%
Total		(573,955)	(311,587)	(5,075)	(173,075)	(9,997)	(32,179)	(34,561)		(3,307)	
(108-394) Tools, Shop & Garage Equip		(6,416,893)									AE-ALL
- Demand	DMD-ALL	(3,322,581)	(2,022,516)	(26,421)	(927,696)	(43,373)	(125,074)	(140,596)		(19,534)	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(3,094,312)	(1,461,064)	(30,315)	(1,007,304)	(68,397)	(234,690)	(245,804)		(17,444)	48%
Total		(6,416,893)	(3,483,580)	(56,736)	(1,935,000)	(111,769)	(359,764)	(386,400)		(36,978)	
(108-395) Laboratory Equip		(250,955)									AE-ALL
- Demand	DMD-ALL	(129,941)	(79,098)	(1,033)	(36,281)	(1,696)	(4,891)	(5,498)		(764)	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(121,014)	(57,140)	(1,186)	(39,394)	(2,675)	(9,178)	(9,613)		(682)	48%
Total		(250,955)	(136,238)	(2,219)	(75,675)	(4,371)	(14,070)	(15,112)		(1,446)	
(108-396) Power Operated Equip		(720,253)									AE-ALL
- Demand	DMD-ALL	(372,937)	(227,014)	(2,966)	(104,128)	(4,868)	(14,039)	(15,781)		(2,193)	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(347,316)	(163,995)	(3,403)	(113,063)	(7,677)	(26,342)	(27,590)		(1,958)	48%
Total		(720,253)	(391,008)	(6,368)	(217,191)	(12,545)	(40,381)	(43,371)		(4,151)	
(108-397) Communication Equip		(7,849,127)									AE-ALL
- Demand	DMD-ALL	(4,064,172)	(2,473,937)	(32,318)	(1,134,756)	(53,053)	(152,990)	(171,976)		(23,894)	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(3,784,954)	(1,787,169)	(37,081)	(1,232,132)	(83,662)	(287,072)	(300,667)		(21,337)	48%
Total		(7,849,127)	(4,261,106)	(69,399)	(2,366,887)	(136,716)	(440,062)	(472,643)		(45,231)	
(108-398) MISC Equip		(128,481)									AE-ALL
- Demand	DMD-ALL	(66,526)	(40,496)	(529)	(18,575)	(868)	(2,504)	(2,815)		(391)	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(61,955)	(29,254)	(607)	(20,169)	(1,369)	(4,699)	(4,922)		(349)	48%
Total		(128,481)	(69,750)	(1,136)	(38,743)	(2,238)	(7,203)	(7,737)		(740)	
(108-399) Other Tangible Property		-									AE-ALL
- Demand	DMD-ALL	-	-	-	-	-	-	-		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	-	-	-	-	-	-	-		-	48%
Total		-	-	-	-	-	-	-		-	
Service Company PIS		(49,961,808)									AE-ALL
- Demand	DMD-ALL	(25,869,552)	(15,747,274)	(205,713)	(7,223,027)	(337,700)	(973,824)	(1,094,674)		(152,092)	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(24,092,256)	(11,375,816)	(236,031)	(7,842,850)	(532,534)	(1,827,291)	(1,913,828)		(135,818)	48%
Total		(49,961,808)	(27,123,090)	(441,744)	(15,065,877)	(870,234)	(2,801,115)	(3,008,502)		(287,910)	
Total Accumulated Depreciation		(1,170,764,729)									
- Demand		(529,008,743)	(346,971,319)	(4,532,627)	(159,150,294)	(7,440,787)	(3,341,857)	(3,756,577)		(3,351,155)	
- Customer		(190,887,368)	(166,942,638)	(2,362,748)	(21,550,804)	(31,178)	-	-		-	
- Commodity		(450,868,618)	(247,181,613)	(5,128,636)	(170,414,882)	(11,571,274)	(6,270,687)	(6,567,655)		(2,951,140)	
Total Accumulated Depreciation		**(1,170,764,729)**	**(761,095,570)**	**(12,024,011)**	**(351,115,979)**	**(19,043,240)**	**(9,612,544)**	**(10,324,232)**		**(6,302,295)**	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG	Classification Factor
OTHER RATE BASE ITEMS											
Other Rate Base Items											
Materials and Supplies		14,639,069									DISTPLT-SEC
- Demand	DISTPLT-SEC-D	6,745,634	4,488,558	58,636	2,058,831	96,257	-	-		43,352	46%
- Customer	DISTPLT-SEC-C	2,250,812	1,968,472	27,860	254,112	368	-	-		-	15%
- Commodity	DISTPLT-SEC-E	5,642,623	3,189,847	66,184	2,199,182	149,326	-	-		38,084	39%
Total		14,639,069	9,646,877	152,680	4,512,125	245,950	-	-		81,436	
Cash Working Capital		37,767,671									CWC-SEC
- Demand	CWC-SEC-D	20,070,297	13,354,815	174,459	6,125,644	286,394	-	-		128,985	53%
- Customer	CWC-SEC-C	970,702	848,938	12,015	109,590	159	-	-		-	3%
- Commodity	CWC-SEC-E	16,726,671	9,455,801	196,193	6,519,130	442,653	-	-		112,894	44%
Total		37,767,671	23,659,554	382,668	12,754,365	729,205	-	-		241,879	
ADIT		(669,175,588)									DISTPLT-SEC
- Demand	DISTPLT-SEC-D	(308,353,877)	(205,179,279)	(2,680,340)	(94,112,512)	(4,400,062)	-	-		(1,981,684)	46%
- Customer	DISTPLT-SEC-C	(102,888,259)	(89,982,054)	(1,273,521)	(11,615,879)	(16,805)	-	-		-	15%
- Commodity	DISTPLT-SEC-E	(257,933,452)	(145,813,070)	(3,025,396)	(100,528,177)	(6,825,924)	-	-		(1,740,885)	39%
Total		(669,175,588)	(440,974,402)	(6,979,256)	(206,256,569)	(11,242,792)	-	-		(3,722,569)	
Net /Loss on Reacq Debt		766,808									DISTPLT-SEC
- Demand	DISTPLT-SEC-D	353,343	235,115	3,071	107,844	5,042	-	-		2,271	46%
- Customer	DISTPLT-SEC-C	117,900	103,110	1,459	13,311	19	-	-		-	15%
- Commodity	DISTPLT-SEC-E	295,566	167,087	3,467	115,195	7,822	-	-		1,995	39%
Total		766,808	505,313	7,998	236,349	12,883	-	-		4,266	
DTA for AMT		5,321,747									DISTPLT-SEC
- Demand	DISTPLT-SEC-D	2,452,243	1,631,728	21,316	748,448	34,992	-	-		15,760	46%
- Customer	DISTPLT-SEC-C	818,239	715,600	10,128	92,378	134	-	-		-	15%
- Commodity	DISTPLT-SEC-E	2,051,265	1,159,606	24,060	799,470	54,284	-	-		13,845	39%
Total		5,321,747	3,506,933	55,504	1,640,295	89,410	-	-		29,604	
Net Operating Reserves		(5,229,228)									PAY-SEC
- Demand	PAY-SEC-D	(2,775,408)	(1,825,564)	(23,848)	(837,358)	(39,149)	(31,857)	-		(17,632)	53%
- Customer	PAY-SEC-C	(98,245)	(83,301)	(1,179)	(10,753)	(16)	-	(2,996)		-	2%
- Commodity	PAY-SEC-E	(2,355,575)	(1,298,021)	(26,932)	(894,897)	(60,764)	(59,463)	-		(15,497)	45%
Total		(5,229,228)	(3,206,886)	(51,959)	(1,743,008)	(99,929)	(91,320)	(2,996)		(33,129)	
NOL		20,182,546									DISTPLT-SEC
- Demand	DISTPLT-SEC-D	9,300,050	6,188,272	80,840	2,838,463	132,707	-	-		59,768	46%
- Customer	DISTPLT-SEC-C	3,103,142	2,713,887	38,410	350,339	507	-	-		-	15%
- Commodity	DISTPLT-SEC-E	7,779,354	4,397,768	91,247	3,031,961	205,872	-	-		52,506	39%
Total		20,182,546	13,299,927	210,497	6,220,763	339,086	-	-		112,274	
CTA		(539,194)									TOTPLT-SEC
- Demand	TOTPLT-SEC-D	(250,695)	(165,661)	(2,164)	(75,986)	(3,553)	(765)	(860)		(1,600)	46.494450%
- Customer	TOTPLT-SEC-C	(76,869)	(67,227)	(951)	(8,678)	(13)	-	-		-	14.256324%
- Commodity	TOTPLT-SEC-E	(211,630)	(117,874)	(2,446)	(81,266)	(5,518)	(1,435)	(1,503)		(1,407)	39.249226%
Total		(539,194)	(350,763)	(5,561)	(165,931)	(9,083)	(2,200)	(2,363)		(3,007)	
Regulatory Asset A&G Capitalization		30,708,163									AE-PRI-GTA&G
- Demand	DMD-PRI	16,248,608	10,384,542	135,657	4,763,226	222,696	642,188	-		100,297	53%
- Customer	CUST-GTA&G	60,399	-	-	-	-	-	60,399		-	0%
- Commodity	NRG-PRI	14,399,157	7,462,397	154,833	5,144,815	349,336	1,198,681	-		89,095	47%
Total		30,708,163	17,846,940	290,491	9,908,041	572,032	1,840,869	60,399		189,392	
Customer Deposits		-									CUS
- Demand		-	-	-	-	-	-	-		-	0%
- Customer		-	-	-	-	-	-	-		-	100%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		-	-	-	-	-	-	-		-	
Customer Advances		(27,862,053)									DISTPLT-SEC
- Demand	DISTPLT-SEC-D	(12,838,741)	(8,542,924)	(111,600)	(3,918,505)	(183,203)	-	-		(82,510)	46%
- Customer	DISTPLT-SEC-C	(4,283,895)	(3,746,528)	(53,025)	(483,643)	(700)	-	-		-	15%
- Commodity	DISTPLT-SEC-E	(10,739,417)	(6,071,129)	(125,967)	(4,185,630)	(284,207)	-	-		(72,484)	39%
Total		(27,862,053)	(18,360,580)	(290,591)	(8,587,778)	(468,109)	-	-		(154,994)	
Customer Refunds		(155,489)									DISTPLT-SEC
- Demand	DISTPLT-SEC-D	(71,649)	(47,675)	(623)	(21,868)	(1,022)	-	-		(460)	46%
- Customer	DISTPLT-SEC-C	(23,907)	(20,908)	(296)	(2,699)	(4)	-	-		-	15%
- Commodity	DISTPLT-SEC-E	(59,933)	(33,881)	(703)	(23,359)	(1,586)	-	-		(405)	39%
Total		(155,489)	(102,464)	(1,622)	(47,926)	(2,612)	-	-		(865)	
Total Other Rate Base Items		(593,575,548)									
- Demand		(269,120,195)	(179,478,073)	(2,344,595)	(82,323,773)	(3,848,901)	609,566	(860)		(1,733,454)	
- Customer		(100,049,983)	(87,550,010)	(1,239,100)	(11,301,924)	(16,351)	-	57,402		-	
- Commodity		(224,405,370)	(127,501,469)	(2,645,458)	(87,903,576)	(5,968,706)	1,137,782	(1,503)		(1,522,260)	
Total		(593,575,548)	(394,529,552)	(6,229,153)	(181,529,274)	(9,833,958)	1,747,349	55,039		(3,255,714)	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
Rate Base Adjustment											
Adjustment											
AMI		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
Delayed Recognition Pension & OPEB		(12,994,369)									PAY-SEC
- Demand	PAY-SEC-D	(6,896,750)	(4,536,436)	(59,261)	(2,080,792)	(97,284)	(79,163)	-		(43,814)	53%
- Customer	PAY-SEC-C	(244,133)	(206,998)	(2,930)	(26,722)	(39)	-	(7,445)		-	2%
- Commodity	PAY-SEC-E	(5,853,486)	(3,225,518)	(66,925)	(2,223,775)	(150,996)	(147,763)	-		(38,510)	45%
Total		(12,994,369)	(7,968,951)	(129,115)	(4,331,288)	(248,318)	(226,926)	(7,445)		(82,324)	
Total Rate Base Adjustment		(12,994,369)									
- Demand		(6,896,750)	(4,536,436)	(59,261)	(2,080,792)	(97,284)	(79,163)	-		(43,814)	
- Customer		(244,133)	(206,998)	(2,930)	(26,722)	(39)	-	(7,445)		-	
- Commodity		(5,853,486)	(3,225,518)	(66,925)	(2,223,775)	(150,996)	(147,763)	-		(38,510)	
Total		(12,994,369)	(7,968,951)	(129,115)	(4,331,288)	(248,318)	(226,926)	(7,445)		(82,324)	
Total Rate Base		**1,612,375,756**									
- Demand		**771,001,532**	**510,464,864**	**6,668,409**	**234,142,215**	**10,946,901**	**1,997,265**	**1,648,037**		**4,930,225**	
- Customer		**192,066,601**	**167,930,259**	**2,376,726**	**21,678,297**	**31,363**	**-**	**49,957**		**-**	
- Commodity		**649,307,622**	**363,123,279**	**7,534,246**	**250,348,761**	**16,998,833**	**3,742,450**	**2,881,277**		**4,335,386**	
Total		**1,612,375,756**	**1,041,518,402**	**16,579,381**	**506,169,273**	**27,977,096**	**5,739,714**	**4,579,271**		**9,265,611**	
OPERATIONS & MAINTENANCE EXPENSES											
Distribution Expenses											
Operations Expenses											
(580) Operation Supervision & Engineering		231,406									AE-SEC
- Demand	DMD-SEC	125,975	83,824	1,095	38,449	1,798	-	-		810	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	105,430	59,601	1,237	41,091	2,790	-	-		712	46%
Total		231,406	143,425	2,332	79,540	4,588	-	-		1,521	
(581) Load Dispatching		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(582) Station Expenses		304,563									AE-SEC
- Demand	DMD-SEC	165,802	110,325	1,441	50,604	2,366	-	-		1,066	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	138,761	78,444	1,628	54,082	3,672	-	-		937	46%
Total		304,563	188,768	3,069	104,686	6,038	-	-		2,002	
(583) Overhead line expenses		520,027									AE-SEC
- Demand	DMD-SEC	283,098	188,374	2,461	86,404	4,040	-	-		1,819	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	236,929	133,939	2,779	92,342	6,270	-	-		1,599	46%
Total		520,027	322,313	5,240	178,746	10,310	-	-		3,418	
(584) Underground line expenses		1,987,209									AE-SEC
- Demand	DMD-SEC	1,081,819	719,845	9,404	330,181	15,437	-	-		6,952	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	905,389	511,828	10,620	352,871	23,960	-	-		6,111	46%
Total		1,987,209	1,231,673	20,023	683,052	39,397	-	-		13,063	
(585) Street lighting and signal system expenses		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(586) Meter expenses		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(587) Customer installations expenses		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(588) Miscellaneous distribution expenses		10,402,194									DISTPLT-SEC
- Demand	DISTPLT-SEC-D	4,793,296	3,189,469	41,665	1,462,959	68,398	-	-		30,805	46%
- Customer	DISTPLT-SEC-C	1,599,376	1,398,752	19,797	180,566	261	-	-		-	15%
- Commodity	DISTPLT-SEC-E	4,009,522	2,266,634	47,029	1,562,689	106,108	-	-		27,062	39%
Total		10,402,194	6,854,855	108,491	3,206,215	174,767	-	-		57,867	
(589) Rents		2,236,678									AE-SEC
- Demand	DMD-SEC	1,217,628	810,212	10,584	371,632	17,375	-	-		7,825	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	1,019,050	576,082	11,953	397,169	26,968	-	-		6,878	46%
Total		2,236,678	1,386,294	22,537	768,801	44,343	-	-		14,703	
Total Dist. Operations Expenses		15,682,077									
- Demand		7,667,619	5,102,049	66,650	2,340,230	109,413	-	-		49,277	
- Customer		1,599,376	1,398,752	19,797	180,566	261	-	-		-	
- Commodity		6,415,081	3,626,527	75,245	2,500,243	169,768	-	-		43,298	
Total		15,682,077	10,127,328	161,692	5,021,040	279,443	-	-		92,575	
Maintenance Expense											
(590) Maintenance Supervision and Engineering		1,786,832									AE-SEC
- Demand	DMD-SEC	972,736	647,261	8,455	296,888	13,880	-	-		6,251	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	814,096	460,219	9,549	317,290	21,544	-	-		5,495	46%
Total		1,786,832	1,107,479	18,004	614,178	35,425	-	-		11,746	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
(591) Maintenance of Structures		-									AE-SEC
- Demand		-	-	-	-	-	-	-		-	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity		-	-	-	-	-	-	-		-	46%
Total		-	-	-	-	-	-	-		-	
(592) Maintenance of Station Equipment		5,986,956									AE-SEC
- Demand	DMD-SEC	3,259,248	2,168,710	28,331	994,753	46,508	-	-		20,946	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	2,727,708	1,542,008	31,994	1,063,110	72,186	-	-		18,410	46%
Total		5,986,956	3,710,718	60,325	2,057,863	118,694	-	-		39,356	
(593) Maintenance of Overhead Lines		42,114,302									AE-SEC
- Demand	DMD-SEC	22,926,667	15,255,450	199,288	6,997,435	327,153	-	-		147,342	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	19,187,635	10,847,015	225,059	7,478,278	507,780	-	-		129,504	46%
Total		42,114,302	26,102,464	424,347	14,475,713	834,932	-	-		276,846	
(594) Maintenance of underground lines		2,286,373									AE-SEC
- Demand	DMD-SEC	1,244,682	828,214	10,819	379,889	17,761	-	-		7,999	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	1,041,691	588,881	12,218	405,994	27,567	-	-		7,031	46%
Total		2,286,373	1,417,095	23,038	785,882	45,328	-	-		15,030	
(595) Maintenance of line transformers		151,393									DEM
- Demand	DMD-SEC	151,393	100,737	1,316	46,207	2,160	-	-		973	100%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		151,393	100,737	1,316	46,207	2,160	-	-		973	
(596) Maintenance of street lighting and signal systems		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(597) Maintenance of meters		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(598) Maintenance of miscellaneous distribution plant		1,160,143									DISTPLT-SEC
- Demand	DISTPLT-SEC-D	534,590	355,717	4,647	163,162	7,628	-	-		3,436	46%
- Customer	DISTPLT-SEC-C	178,376	156,001	2,208	20,138	29	-	-		-	15%
- Commodity	DISTPLT-SEC-E	447,177	252,795	5,245	174,285	11,834	-	-		3,018	39%
Total		1,160,143	764,513	12,100	357,585	19,492	-	-		6,454	
Total Dist. Maintenance Expenses		53,486,000									
- Demand		29,089,317	19,356,089	252,856	8,878,334	415,091	-	-		186,947	
- Customer		178,376	156,001	2,208	20,138	29	-	-		-	
- Commodity		24,218,307	13,690,918	284,065	9,438,955	640,911	-	-		163,458	
Total		53,486,000	33,203,007	539,130	18,337,427	1,056,031	-	-		350,405	
Total Distribution Expenses		69,168,077									
- Demand		36,756,936	24,458,138	319,507	11,218,564	524,504	-	-		236,224	
- Customer		1,777,753	1,554,753	22,005	200,705	290	-	-		-	
- Commodity		30,633,388	17,317,445	359,310	11,939,198	810,679	-	-		206,756	
Total		69,168,077	43,330,336	700,821	23,358,467	1,335,473	-	-		442,980	
Customer Account Expense											
(901) Supervision		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(902) Meter reading expenses		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(903) Customer records and collection expenses		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(904) Uncollectible accounts		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(905) Miscellaneous customer accounts expenses		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
Total Customer Account Expenses		-									
- Demand		-	-	-	-	-	-	-		-	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		-	-	-	-	-	-	-		-	
Total		-	-	-	-	-	-	-		-	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
Customer Service Expenses											
(907) Customer Service Supervision		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(908) Customer Assistance		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(909) Informational and instructional advertising		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(910) Miscellaneous customer service and informational		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
Total Customer Service Expenses		-									
- Demand		-	-	-	-	-	-	-		-	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		-	-	-	-	-	-	-		-	
Total		-	-	-	-	-	-	-		-	
Sales Expenses											
(911) Sales Exp		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
Total Sales Expenses		-									
- Demand		-	-	-	-	-	-	-		-	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		-	-	-	-	-	-	-		-	
Total		-	-	-	-	-	-	-		-	
Administrative & General Expense											
Labor Related											
(920) Administrative and general salaries		4,744,521									AE-PRI-GTA&G
- Demand	DMD-PRI	2,510,468	1,604,449	20,960	735,936	34,407	99,220	-		15,496	53%
- Customer	CUST-GTA&G	9,332	-	-	-	-	-	9,332		-	0%
- Commodity	NRG-PRI	2,224,721	1,152,967	23,922	794,892	53,974	185,200	-		13,765	47%
Total		4,744,521	2,757,416	44,882	1,530,828	88,381	284,421	9,332		29,262	
(921) Office supplies and expenses		424,403									AE-PRI-GTA&G
- Demand	DMD-PRI	224,564	143,520	1,875	65,830	3,078	8,875	-		1,386	53%
- Customer	CUST-GTA&G	835	-	-	-	-	-	835		-	0%
- Commodity	NRG-PRI	199,004	103,134	2,140	71,104	4,828	16,566	-		1,231	47%
Total		424,403	246,654	4,015	136,934	7,906	25,442	835		2,617	
(922) Administrative expenses transferred—Credit		(422,542)									AE-PRI-GTA&G
- Demand	DMD-PRI	(223,580)	(142,891)	(1,867)	(65,542)	(3,064)	(8,836)	-		(1,380)	53%
- Customer	CUST-GTA&G	(831)	-	-	-	-	-	(831)		-	0%
- Commodity	NRG-PRI	(198,131)	(102,682)	(2,130)	(70,792)	(4,807)	(16,494)	-		(1,226)	47%
Total		(422,542)	(245,573)	(3,997)	(136,334)	(7,871)	(25,330)	(831)		(2,606)	
(923) Outside services employed		15,453,805									AE-PRI-GTA&G
- Demand	DMD-PRI	8,177,071	5,225,995	68,269	2,397,082	112,071	323,180	-		50,474	53%
- Customer	CUST-GTA&G	30,395	-	-	-	-	-	30,395		-	0%
- Commodity	NRG-PRI	7,246,339	3,755,433	77,919	2,589,115	175,802	603,233	-		44,837	47%
Total		15,453,805	8,981,427	146,189	4,986,197	287,874	926,413	30,395		95,311	
(926) Employee pensions and benefits		(954,134)									AE-PRI-GTA&G
- Demand	DMD-PRI	(504,861)	(322,658)	(4,215)	(147,998)	(6,919)	(19,953)	-		(3,116)	53%
- Customer	CUST-GTA&G	(1,877)	-	-	-	-	-	(1,877)		-	0%
- Commodity	NRG-PRI	(447,397)	(231,864)	(4,811)	(159,855)	(10,854)	(37,244)	-		(2,768)	47%
Total		(954,134)	(554,523)	(9,026)	(307,853)	(17,774)	(57,198)	(1,877)		(5,885)	
(426) Pension / OPEB Non-Service Cost		-									AE-PRI-GTA&G
- Demand		-	-	-	-	-	-	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity		-	-	-	-	-	-	-		-	47%
Total		-	-	-	-	-	-	-		-	
(924) Property insurance		157,595									AE-PRI-GTA&G
- Demand	DMD-PRI	83,388	53,294	696	24,445	1,143	3,296	-		515	53%
- Customer	CUST-GTA&G	310	-	-	-	-	-	310		-	0%
- Commodity	NRG-PRI	73,897	38,297	795	26,403	1,793	6,152	-		457	47%
Total		157,595	91,591	1,491	50,848	2,936	9,447	310		972	
(925) Injuries and damages		2,878,295									AE-PRI-GTA&G
- Demand	DMD-PRI	1,522,992	973,350	12,715	446,460	20,873	60,193	-		9,401	53%
- Customer	CUST-GTA&G	5,661	-	-	-	-	-	5,661		-	0%
- Commodity	NRG-PRI	1,349,642	699,455	14,513	482,227	32,743	112,353	-		8,351	47%
Total		2,878,295	1,672,805	27,228	928,687	53,617	172,546	5,661		17,752	
(935) Maintenance of general plant		2,574,516									AE-PRI-GTA&G
- Demand	DMD-PRI	1,362,254	870,621	11,373	399,340	18,670	53,840	-		8,409	53%
- Customer	CUST-GTA&G	5,064	-	-	-	-	-	5,064		-	0%
- Commodity	NRG-PRI	1,207,199	625,634	12,981	431,332	29,288	100,495	-		7,470	47%
Total		2,574,516	1,496,255	24,354	830,672	47,958	154,335	5,064		15,878	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
(929) Duplicate charges—Credit		-									AE-PRI-GTA&G
- Demand		-	-	-	-	-	-	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity		-	-	-	-	-	-	-		-	47%
Total		-	-	-	-	-	-	-		-	
(928) Regulatory commission expenses		1,696,822									AE-PRI-GTA&G
- Demand	DMD-PRI	897,840	573,812	7,496	263,199	12,305	35,485	-		5,542	53%
- Customer	CUST-GTA&G	3,337	-	-	-	-	-	3,337		-	0%
- Commodity	NRG-PRI	795,646	412,345	8,556	284,284	19,303	66,235	-		4,923	47%
Total		1,696,822	986,158	16,051	547,483	31,608	101,720	3,337		10,465	
(930.1) Gen Advertising Exp		272,186									AE-PRI-GTA&G
- Demand	DMD-PRI	144,022	92,045	1,202	42,220	1,974	5,692	-		889	53%
- Customer	CUST-GTA&G	535	-	-	-	-	-	535		-	0%
- Commodity	NRG-PRI	127,629	66,144	1,372	45,602	3,096	10,625	-		790	47%
Total		272,186	158,189	2,575	87,821	5,070	16,317	535		1,679	
(930.2) Misc Gen Exp		852,224									AE-PRI-GTA&G
- Demand	DMD-PRI	450,937	288,196	3,765	132,191	6,180	17,822	-		2,783	53%
- Customer	CUST-GTA&G	1,676	-	-	-	-	-	1,676		-	0%
- Commodity	NRG-PRI	399,611	207,099	4,297	142,781	9,695	33,266	-		2,473	47%
Total		852,224	495,295	8,062	274,971	15,875	51,088	1,676		5,256	
(931) Rents		754,571									AE-PRI-GTA&G
- Demand	DMD-PRI	399,266	255,172	3,333	117,044	5,472	15,780	-		2,465	53%
- Customer	CUST-GTA&G	1,484	-	-	-	-	-	1,484		-	0%
- Commodity	NRG-PRI	353,821	183,368	3,805	126,420	8,584	29,454	-		2,189	47%
Total		754,571	438,541	7,138	243,464	14,056	45,234	1,484		4,654	
(932) Institutional Ad - Newspaper		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(933) Transportation expenses		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total A&G Expense		28,432,263									
- Demand		15,044,361	9,614,904	125,603	4,410,205	206,191	594,593	-		92,864	
- Customer		55,922	-	-	-	-	-	55,922		-	
- Commodity		13,331,980	6,909,330	143,358	4,763,513	323,445	1,109,842	-		82,492	
Total		28,432,263	16,524,234	268,961	9,173,718	529,637	1,704,435	55,922		175,355	
O&M Adjustment											
Adjustment											
Int on Cust Deposits		-									CUS
- Demand		-	-	-	-	-	-	-		-	0%
- Customer	CUST-DEP	-	-	-	-	-	-	-		-	100%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		-	-	-	-	-	-	-		-	
Annualize Payroll Increase		1,882,187									PAY-SEC
- Demand	PAY-SEC-D	998,969	657,086	8,584	301,395	14,091	11,467	-		6,346	53%
- Customer	PAY-SEC-C	35,362	29,983	424	3,871	6	-	1,078		-	2%
- Commodity	PAY-SEC-E	847,856	467,205	9,694	322,106	21,871	21,403	-		5,578	45%
Total		1,882,187	1,154,274	18,702	627,371	35,968	32,869	1,078		11,924	
Svngs Pln Match on Payroll Inc		56,466									PAY-SEC
- Demand	PAY-SEC-D	29,969	19,713	258	9,042	423	344	-		190	53%
- Customer	PAY-SEC-C	1,061	899	13	116	0	-	32		-	2%
- Commodity	PAY-SEC-E	25,436	14,016	291	9,663	656	642	-		167	45%
Total		56,466	34,628	561	18,821	1,079	986	32		358	
Reclass Amortization of Net Loss on Reacquired Debt		355,159									DISTPLT-SEC
- Demand	DISTPLT-SEC-D	163,656	108,897	1,423	49,949	2,335	-	-		1,052	46%
- Customer	DISTPLT-SEC-C	54,607	47,757	676	6,165	9	-	-		-	15%
- Commodity	DISTPLT-SEC-E	136,896	77,389	1,606	53,354	3,623	-	-		924	39%
Total		355,159	234,043	3,704	109,469	5,967	-	-		1,976	
BPU & RPA Assessments		454,999									DIST-REV
- Demand	DIST-REV-DMD	120,160	-	-	77,644	6,125	15,108	11,227		9,841	26%
- Customer	DIST-REV-CUST	36,637	26,131	797	8,973	76	294	364		-	8%
- Commodity	DIST-REV-NRG	298,201	221,487	4,097	60,494	1,509	3,884	2,940		3,791	66%
Total		454,999	247,618	4,894	147,111	7,709	19,287	14,530		13,631	
Rate Case Exp		-									AE-ALL
- Demand	DMD-ALL	-	-	-	-	-	-	-		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	-	-	-	-	-	-	-		-	48%
Total		-	-	-	-	-	-	-		-	
Pension Smoothing		5,146,795									PAY-SEC
- Demand	PAY-SEC-D	2,731,657	1,796,787	23,472	824,158	38,532	31,355	-		17,354	53%
- Customer	PAY-SEC-C	96,696	81,987	1,160	10,584	15	-	2,949		-	2%
- Commodity	PAY-SEC-E	2,318,442	1,277,560	26,507	880,790	59,806	58,526	-		15,253	45%
Total		5,146,795	3,156,334	51,140	1,715,532	98,354	89,881	2,949		32,607	
OPEB Smoothing		1,766,078									PAY-SEC
- Demand	PAY-SEC-D	937,344	616,552	8,054	282,802	13,222	10,759	-		5,955	53%
- Customer	PAY-SEC-C	33,180	28,133	398	3,632	5	-	1,012		-	2%
- Commodity	PAY-SEC-E	795,553	438,383	9,096	302,235	20,522	20,083	-		5,234	45%
Total		1,766,078	1,083,068	17,548	588,670	33,749	30,842	1,012		11,189	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	Lighting LTG	Classification Factor
Normalize Vegetation Management Expense		4,138,329								OHPLT-SEC
- Demand	OHPLT-SEC-D	2,252,871	1,499,065	19,583	687,597	32,147	-	-	14,478	54%
- Customer	OHPLT-SEC-C	-	-	-	-	-	-	-	-	0%
- Commodity	OHPLT-SEC-E	1,885,458	1,065,873	22,115	734,847	49,897	-	-	12,726	46%
Total		4,138,329	2,564,938	41,698	1,422,445	82,044	-	-	27,204	
ServCo Depr @ JCP&L Rates		989,041								AE-ALL
- Demand	DMD-ALL	512,112	311,732	4,072	142,987	6,685	19,278	21,670	3,011	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	476,929	225,195	4,672	155,257	10,542	36,173	37,886	2,689	48%
Total		989,041	536,927	8,745	298,243	17,227	55,451	59,556	5,699	
SERP/EDCP		1,772,079								PAY-SEC
- Demand	PAY-SEC-D	940,529	618,647	8,082	283,764	13,267	10,796	-	5,975	53%
- Customer	PAY-SEC-C	33,293	28,229	400	3,644	5	-	1,015	-	2%
- Commodity	PAY-SEC-E	798,257	439,873	9,127	303,263	20,592	20,151	-	5,252	45%
Total		1,772,079	1,086,749	17,608	590,670	33,864	30,947	1,015	11,227	
Advertising removal		-								#N/A
- Demand		-	-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	-	
BGS Administrative Labor included in BGS Deferral		-								AE-ALL
- Demand	DMD-ALL	-	-	-	-	-	-	-	-	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	-	-	-	-	-	-	-	-	48%
Total		-	-	-	-	-	-	-	-	
Low Income O&M		881,687								AE-ALL
- Demand	DMD-ALL	456,526	277,896	3,630	127,466	5,959	17,185	19,318	2,684	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	425,162	200,752	4,165	138,405	9,398	32,247	33,774	2,397	48%
Total		881,687	478,647	7,796	265,871	15,357	49,432	53,092	5,081	
Contract Labor/Fuel Costs		-								#N/A
- Demand		-	-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	-	
Total O&M Adjustment		17,442,819								
- Demand		9,143,795	5,906,373	77,157	2,786,805	132,787	116,292	52,215	66,886	
- Customer		290,836	243,120	3,868	36,984	116	294	6,451	-	
- Commodity		8,008,189	4,427,733	91,370	2,960,414	198,415	193,108	74,599	54,010	
Total		17,442,819	10,577,226	172,396	5,784,203	331,318	309,694	133,265	120,896	
Total O&M Expenses		115,043,159								
- Demand		60,945,092	39,979,415	522,267	18,415,574	863,482	710,885	52,215	395,974	
- Customer		2,124,511	1,797,873	25,873	237,689	407	294	62,373	-	
- Commodity		51,973,556	28,654,508	594,038	19,663,125	1,332,539	1,302,950	74,599	343,257	
Total		**115,043,159**	**70,431,796**	**1,142,178**	**38,316,387**	**2,196,428**	**2,014,129**	**189,188**	**739,231**	
DEPRECIATION EXPENSE										
Depreciation Expense										
(403-360) Land & Land Rights		66,658								AE-SEC
- Demand	DMD-SEC	36,288	24,146	315	11,075	518	-	-	233	54%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-SEC	30,370	17,168	356	11,836	804	-	-	205	46%
Total		66,658	41,314	672	22,912	1,322	-	-	438	
(403-361) Struct & Impmnts		526,520								AE-SEC
- Demand	DMD-SEC	286,633	190,726	2,492	87,483	4,090	-	-	1,842	54%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-SEC	239,887	135,611	2,814	93,495	6,348	-	-	1,619	46%
Total		526,520	326,338	5,305	180,978	10,438	-	-	3,461	
(403-362) Station Equip		4,393,098								AE-SEC
- Demand	DMD-SEC	2,391,565	1,591,352	20,788	729,928	34,126	-	-	15,370	54%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-SEC	2,001,533	1,131,492	23,477	780,087	52,968	-	-	13,509	46%
Total		4,393,098	2,722,844	44,265	1,510,015	87,095	-	-	28,879	
(403-364) Poles, Towers & Fixt		9,069,659								AE-SEC
- Demand	DMD-SEC	4,937,445	3,285,386	42,918	1,506,955	70,455	-	-	31,731	54%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-SEC	4,132,214	2,335,993	48,468	1,610,508	109,354	-	-	27,890	46%
Total		9,069,659	5,621,379	91,387	3,117,463	179,809	-	-	59,621	
(403-365) OH Cond & Dev		20,988,905								AE-SEC
- Demand	DMD-SEC	11,426,181	7,603,004	99,321	3,487,378	163,046	-	-	73,432	54%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-SEC	9,562,724	5,405,930	112,165	3,727,020	253,067	-	-	64,542	46%
Total		20,988,905	13,008,933	211,486	7,214,399	416,113	-	-	137,974	
(403-366) UG Conduit		110,080								AE-SEC
- Demand	DMD-SEC	59,926	39,875	521	18,290	855	-	-	385	54%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-SEC	50,153	28,352	588	19,547	1,327	-	-	339	46%
Total		110,080	68,227	1,109	37,837	2,182	-	-	724	
(403-367) UG Cond & Dev		6,410,848								AE-SEC
- Demand	DMD-SEC	3,490,011	2,322,260	30,337	1,065,184	49,801	-	-	22,429	54%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-SEC	2,920,837	1,651,186	34,260	1,138,380	77,297	-	-	19,714	46%
Total		6,410,848	3,973,446	64,596	2,203,565	127,098	-	-	42,143	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
(403-368) Line Transformers		18,448,452									AE-SEC
- Demand	DMD-SEC	10,043,180	6,682,752	87,299	3,065,273	143,311	-	-		64,544	54%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-SEC	8,405,272	4,751,607	98,589	3,275,910	222,436	-	-		56,730	46%
Total		18,448,452	11,434,359	185,888	6,341,183	365,748	-	-		121,274	
(403-369) Services		7,940,911									SRVC
- Demand	DMD-SEC	12,158	8,090	106	3,711	173	-	-		78	0%
- Customer	CUST-SVCS	7,928,753	6,934,178	98,140	895,140	1,295	-	-		-	100%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		7,940,911	6,942,268	98,245	898,851	1,469	-	-		78	
(403-370) Meters		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(403-371) Install on Cust Premise		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(403-373) St Lt & Signal Sys		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(403-374) Asset Ret Costs		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(403-389) Land & Land Rights		244									AE-ALL
- Demand	DMD-ALL	126	77	1	35	2	5	5		1	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	118	55	1	38	3	9	9		1	48%
Total		244	132	2	73	4	14	15		1	
(403-390) Struct & Impmnts -		774,213									AE-ALL
- Demand	DMD-ALL	400,877	244,021	3,188	111,929	5,233	15,090	16,963		2,357	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	373,336	176,281	3,658	121,534	8,252	28,316	29,657		2,105	48%
Total		774,213	420,302	6,845	233,462	13,485	43,406	46,620		4,461	
(403-391) Office Furn & Equip		3,821,378									AE-ALL
- Demand	DMD-ALL	1,978,658	1,204,446	15,734	552,460	25,829	74,484	83,727		11,633	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	1,842,720	870,091	18,053	599,868	40,731	139,762	146,381		10,388	48%
Total		3,821,378	2,074,536	33,787	1,152,329	66,561	214,246	230,108		22,021	
(403-392) Transportation Equip		887,409									AE-ALL
- Demand	DMD-ALL	459,488	279,699	3,654	128,294	5,998	17,297	19,443		2,701	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	427,920	202,054	4,192	139,303	9,459	32,456	33,993		2,412	48%
Total		887,409	481,753	7,846	267,596	15,457	49,753	53,436		5,114	
(403-393) Stores Equip		11,610									AE-ALL
- Demand	DMD-ALL	6,012	3,659	48	1,678	78	226	254		35	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	5,599	2,643	55	1,823	124	425	445		32	48%
Total		11,610	6,303	103	3,501	202	651	699		67	
(403-394) Tools, Shop & Garage Equip		533,038									AE-ALL
- Demand	DMD-ALL	276,000	168,006	2,195	77,062	3,603	10,390	11,679		1,623	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	257,038	121,368	2,518	83,675	5,682	19,495	20,418		1,449	48%
Total		533,038	289,374	4,713	160,737	9,284	29,885	32,097		3,072	
(403-395) Laboratory Equip		10,935									AE-ALL
- Demand	DMD-ALL	5,662	3,447	45	1,581	74	213	240		33	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	5,273	2,490	52	1,717	117	400	419		30	48%
Total		10,935	5,937	97	3,298	190	613	658		63	
(403-396) Power Operated Equip		33,347									AE-ALL
- Demand	DMD-ALL	17,267	10,511	137	4,821	225	650	731		102	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	16,080	7,593	158	5,235	355	1,220	1,277		91	48%
Total		33,347	18,103	295	10,056	581	1,870	2,008		192	
(403-397) Communication Equip		1,887,133									AE-ALL
- Demand	DMD-ALL	977,132	594,798	7,770	272,825	12,755	36,783	41,347		5,745	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	910,001	429,682	8,915	296,236	20,115	69,020	72,288		5,130	48%
Total		1,887,133	1,024,480	16,685	569,061	32,870	105,802	113,636		10,875	
(403-398) MISC Equip		(9,875)									AE-ALL
- Demand	DMD-ALL	(5,113)	(3,113)	(41)	(1,428)	(67)	(192)	(216)		(30)	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(4,762)	(2,249)	(47)	(1,550)	(105)	(361)	(378)		(27)	48%
Total		(9,875)	(5,361)	(87)	(2,978)	(172)	(554)	(595)		(57)	
Total Depreciation Expense		75,904,563									
- Demand		36,799,497	24,253,142	316,829	11,124,535	520,108	154,945	174,174		234,244	
- Customer		7,928,753	6,934,178	98,140	895,140	1,295	-	-		-	
- Commodity		31,176,313	17,267,349	358,271	11,904,661	808,334	290,741	304,509		206,158	
Total		75,904,563	48,454,669	773,239	23,924,336	1,329,736	445,686	478,683		440,402	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	Lighting LTG	Classification Factor
Depreciation Adjustment										
Adjustment										
Annualize Deprec Exp		5,061,087								DPR-TOT-SEC
- Demand	DPR-TOT-SEC-D	2,453,680	1,617,126	21,125	741,750	34,679	10,331	11,613	15,619	48%
- Customer	DPR-TOT-SEC-C	528,665	462,350	6,544	59,685	86	-	-	-	10%
- Commodity	DPR-TOT-SEC-E	2,078,743	1,151,335	23,888	793,767	53,897	19,386	20,304	13,746	41%
Total		5,061,087	3,230,811	51,557	1,595,203	88,663	29,717	31,917	29,365	
Average Net Salvage		2,469,789								DISTPLT-SEC
- Demand	DISTPLT-SEC-D	1,138,070	757,274	9,893	347,350	16,240	-	-	7,314	46%
- Customer	DISTPLT-SEC-C	379,739	332,105	4,700	42,872	62	-	-	-	15%
- Commodity	DISTPLT-SEC-E	951,979	538,166	11,166	371,029	25,193	-	-	6,425	39%
Total		2,469,789	1,627,545	25,759	761,250	41,495	-	-	13,739	
Total Depreciation Adjustment		7,530,876								
- Demand		3,591,750	2,374,401	31,018	1,089,100	50,919	10,331	11,613	22,933	
- Customer		908,405	794,455	11,244	102,557	148	-	-	-	
- Commodity		3,030,722	1,689,501	35,055	1,164,796	79,090	19,386	20,304	20,171	
Total		7,530,876	4,858,357	77,316	2,356,453	130,158	29,717	31,917	43,104	
Total Depreciation Expense										
- Demand		40,391,247	26,627,543	347,846	12,213,636	571,027	165,277	185,787	257,177	
- Customer		8,837,158	7,728,633	109,384	997,698	1,443	-	-	-	
- Commodity		34,207,035	18,956,850	393,325	13,069,456	887,424	310,126	324,813	226,329	
Total		**83,435,439**	**53,313,026**	**850,555**	**26,280,789**	**1,459,894**	**475,403**	**510,600**	**483,506**	
Amortization, Accretion, Regulatory Debits and Credits										
Amort - Ltd Term Elec Prpty		6,961,838								DISTPLT-SEC
- Demand	DISTPLT-SEC-D	3,207,992	2,134,604	27,885	979,109	45,777	-	-	20,617	46%
- Customer	DISTPLT-SEC-C	1,070,409	936,138	13,249	120,847	175	-	-	-	15%
- Commodity	DISTPLT-SEC-E	2,683,437	1,516,981	31,475	1,045,855	71,014	-	-	18,111	39%
Total		6,961,838	4,587,723	72,609	2,145,812	116,966	-	-	38,728	
Accretion Expense		225,877								AE-ALL
- Demand	DMD-ALL	116,956	71,193	930	32,655	1,527	4,403	4,949	688	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	108,921	51,430	1,067	35,457	2,408	8,261	8,652	614	48%
Total		225,877	122,623	1,997	68,113	3,934	12,664	13,601	1,302	
Regulatory Debits		36,620,730								AE-ALL
- Demand	DMD-ALL	18,961,722	11,542,350	150,782	5,294,295	247,525	713,788	802,368	111,480	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	17,659,009	8,338,183	173,004	5,748,609	390,334	1,339,357	1,402,787	99,551	48%
Total		36,620,730	19,880,533	323,787	11,042,904	637,859	2,053,146	2,205,155	211,030	
Regulatory Credits		15,253								AE-ALL
- Demand	DMD-ALL	7,898	4,808	63	2,205	103	297	334	46	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	7,355	3,473	72	2,394	163	558	584	41	48%
Total		15,253	8,281	135	4,600	266	855	919	88	
Total Depreciation and Amortization		127,259,138								
- Demand		62,685,814	40,380,498	527,507	18,521,900	865,958	883,765	993,439	390,007	
- Customer		9,907,567	8,664,771	122,633	1,118,545	1,618	-	-	-	
- Commodity		54,665,757	28,866,917	598,944	19,901,772	1,351,342	1,658,303	1,736,837	344,647	
Total		**127,259,138**	**77,912,186**	**1,249,084**	**39,542,217**	**2,218,919**	**2,542,067**	**2,730,275**	**734,654**	
TAXES										
Taxes Other than Income										
(408) Payroll Taxes		1,246,572								PAY-SEC
- Demand	PAY-SEC-D	661,617	435,188	5,685	199,614	9,333	7,594	-	4,203	53%
- Customer	PAY-SEC-C	23,420	19,858	281	2,563	4	-	714	-	2%
- Commodity	PAY-SEC-E	561,535	309,430	6,420	213,331	14,485	14,175	-	3,694	45%
Total		1,246,572	764,475	12,386	415,508	23,822	21,769	714	7,898	
(408) Property Taxes		3,006,641								RB-SEC
- Demand	RB-SEC-D	1,437,708	951,878	12,435	436,611	20,413	3,724	3,073	9,194	48%
- Customer	RB-SEC-C	358,152	313,144	4,432	40,424	58	-	93	-	12%
- Commodity	RB-SEC-E	1,210,782	677,126	14,049	466,832	31,698	6,979	5,373	8,084	40%
Total		3,006,641	1,942,148	30,916	943,868	52,170	10,703	8,539	17,278	
Total Taxes Other than Income		4,253,214								
- Demand		2,099,325	1,387,066	18,120	636,225	29,746	11,319	3,073	13,397	
- Customer		381,572	333,002	4,713	42,988	62	-	807	-	
- Commodity		1,772,317	986,555	20,469	680,163	46,183	21,154	5,373	11,779	
Total Taxes Other than Income		**4,253,214**	**2,706,623**	**43,302**	**1,359,376**	**75,991**	**32,472**	**9,253**	**25,175**	
Total Expenses		**246,555,511**								
- Demand		**125,730,230**	**81,746,979**	**1,067,894**	**37,573,699**	**1,759,186**	**1,605,968**	**1,048,727**	**799,378**	
- Customer		**12,413,650**	**10,795,646**	**153,219**	**1,399,221**	**2,087**	**294**	**63,180**	**-**	
- Commodity		**108,411,631**	**58,507,980**	**1,213,451**	**40,245,060**	**2,730,065**	**2,982,407**	**1,816,809**	**699,682**	
Total		**246,555,511**	**151,050,605**	**2,434,564**	**79,217,980**	**4,491,338**	**4,588,669**	**2,928,716**	**1,499,060**	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Secondary	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
REVENUE REQUIREMENT CALCULATION											
Total Rate Base											
- Demand		771,001,532	510,464,864	6,668,409	234,142,215	10,946,901	1,997,265	1,648,037		4,930,225	
- Customer		192,066,601	167,930,259	2,376,726	21,678,297	31,363	-	49,957		-	
- Commodity		649,307,622	363,123,279	7,534,246	250,348,761	16,998,833	3,742,450	2,881,277		4,335,386	
Total		1,612,375,756	1,041,518,402	16,579,381	506,169,273	27,977,096	5,739,714	4,579,271		9,265,611	
Required Net Income											
- Demand		58,596,116	38,795,330	506,799	17,794,808	831,964	151,792	125,251		374,697	
- Customer		14,597,062	12,762,700	180,631	1,647,551	2,384	-	3,797		-	
- Commodity		49,347,379	27,597,369	572,603	19,026,506	1,291,911	284,426	218,977		329,489	
Total		122,540,557	79,155,399	1,260,033	38,468,865	2,126,259	436,218	348,025		704,186	
Interest Synchronization											
- Demand		16,955,341	11,225,796	146,647	5,149,096	240,737	43,922	36,243		108,422	
- Customer		4,223,798	3,693,008	52,267	476,734	690	-	1,099		-	
- Commodity		14,279,132	7,985,560	165,688	5,505,500	373,827	82,301	63,363		95,341	
Total		35,458,271	22,904,364	364,602	11,131,330	615,253	126,224	100,704		203,763	
Net Income Before Income Taxes											
- Demand		41,640,775	27,569,534	360,152	12,645,712	591,228	107,870	89,008		266,275	
- Customer		10,373,264	9,069,692	128,364	1,170,816	1,694	-	2,698		-	
- Commodity		35,068,248	19,611,809	406,915	13,521,006	918,085	202,125	155,614		234,148	
Total		87,082,286	56,251,034	895,431	27,337,534	1,511,006	309,994	247,320		500,423	
Taxable Income											
- Demand		57,922,903	38,349,609	500,976	17,590,363	822,406	150,048	123,812		370,392	
- Customer		14,429,355	12,616,068	178,556	1,628,622	2,356	-	3,753		-	
- Commodity		48,780,425	27,280,302	566,024	18,807,910	1,277,068	281,158	216,461		325,704	
Total		121,132,684	78,245,979	1,245,556	38,026,894	2,101,831	431,207	344,026		696,096	
NJ State Corporate Business Tax											
- Demand		5,213,061	3,451,465	45,088	1,583,133	74,017	13,504	11,143		33,335	
- Customer		1,298,642	1,135,446	16,070	146,576	212	-	338		-	
- Commodity		4,390,238	2,455,227	50,942	1,692,712	114,936	25,304	19,482		29,313	
Total		10,901,942	7,042,138	112,100	3,422,420	189,165	38,809	30,962		62,649	
Federal Taxable Income											
- Demand		52,709,842	34,898,144	455,889	16,007,230	748,389	136,544	112,669		337,057	
- Customer		13,130,713	11,480,622	162,486	1,482,046	2,144	-	3,415		-	
- Commodity		44,390,187	24,825,075	515,082	17,115,198	1,162,132	255,854	196,980		296,390	
Total		110,230,742	71,203,841	1,133,456	34,604,474	1,912,666	392,398	313,064		633,447	
Federal Income Tax											
- Demand		11,069,067	7,328,610	95,737	3,361,518	157,162	28,674	23,660		70,782	
- Customer		2,757,450	2,410,931	34,122	311,230	450	-	717		-	
- Commodity		9,321,939	5,213,266	108,167	3,594,192	244,048	53,729	41,366		62,242	
Total		23,148,456	14,952,807	238,026	7,266,940	401,660	82,404	65,743		133,024	
NJ Federal & State Income Tax		34,050,397									
- Demand		16,282,128	10,780,075	140,824	4,944,651	231,178	42,179	34,803		104,117	
- Customer		4,056,092	3,546,377	50,192	457,806	662	-	1,055		-	
- Commodity		13,712,178	7,668,493	159,109	5,286,903	358,984	79,034	60,847		91,555	
Total		34,050,397	21,994,945	350,126	10,689,360	590,825	121,212	96,706		195,673	
Tax Reform Amortization		(4,995,178)									RB-SEC
- Demand	RB-SEC-D	(2,388,581)	(1,581,432)	(20,659)	(725,378)	(33,914)	(6,188)	(5,106)		(15,274)	48%
- Customer	RB-SEC-C	(595,027)	(520,252)	(7,363)	(67,160)	(97)	-	(155)		-	12%
- Commodity	RB-SEC-E	(2,011,570)	(1,124,965)	(23,341)	(775,586)	(52,663)	(11,594)	(8,926)		(13,431)	40%
Total		(4,995,178)	(3,226,649)	(51,363)	(1,568,124)	(86,674)	(17,782)	(14,187)		(28,705)	
Investment Tax Credit		(72,848)									RB-SEC
- Demand	RB-SEC-D	(34,834)	(23,063)	(301)	(10,579)	(495)	(90)	(74)		(223)	48%
- Customer	RB-SEC-C	(8,678)	(7,587)	(107)	(979)	(1)	-	(2)		-	12%
- Commodity	RB-SEC-E	(29,336)	(16,406)	(340)	(11,311)	(768)	(169)	(130)		(196)	40%
Total		(72,848)	(47,057)	(749)	(22,869)	(1,264)	(259)	(207)		(419)	
Federal & State Income Taxes											
- Demand		13,858,713	9,175,580	119,864	4,208,694	196,770	35,901	29,623		88,621	
- Customer		3,452,387	3,018,538	42,722	389,666	564	-	898		-	
- Commodity		11,671,271	6,527,122	135,428	4,500,006	305,553	67,270	51,791		77,928	
Total		28,982,371	18,721,239	298,014	9,098,367	502,887	103,171	82,312		166,549	
Revenue Requirement											
- Demand		**198,185,059**	**129,717,888**	**1,694,557**	**59,577,202**	**2,787,920**	**1,793,661**	**1,203,601**		**1,262,696**	
- Customer		**30,463,099**	**26,576,883**	**376,571**	**3,436,438**	**5,035**	**294**	**67,875**		**-**	
- Commodity		**169,430,281**	**92,632,471**	**1,921,482**	**63,771,572**	**4,327,530**	**3,334,103**	**2,087,577**		**1,107,100**	
Total		**398,078,439**	**248,927,243**	**3,992,610**	**126,785,211**	**7,120,484**	**5,128,059**	**3,359,053**		**2,369,796**	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG	Classification Factor
UTILITY PLANT											
Intangible Plant											
(301) Organizational Costs		4,639									AE-ALL
- Demand	DMD-ALL	2,402	1,462	19	671	31	90	102		14	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	2,237	1,056	22	728	49	170	178		13	48%
Total		4,639	2,518	41	1,399	81	260	279		27	
(302) Franchises & Consents		246									AE-ALL
- Demand	DMD-ALL	128	78	1	36	2	5	5		1	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	119	56	1	39	3	9	9		1	48%
Total		246	134	2	74	4	14	15		1	
(303) Misc. Intangible Plant		16,378,987									AE-ALL
- Demand	DMD-ALL	8,480,819	5,162,431	67,439	2,367,926	110,708	319,249	358,867		49,860	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	7,898,168	3,729,335	77,378	2,571,123	174,581	599,041	627,410		44,525	48%
Total		16,378,987	8,891,767	144,817	4,939,049	285,289	918,290	986,278		94,385	
Total Intangible Plant		16,383,872									
- Demand		8,483,349	5,163,971	67,459	2,368,632	110,741	319,344	358,974		49,875	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		7,900,524	3,730,448	77,401	2,571,889	174,633	599,220	627,598		44,538	
Total		16,383,872	8,894,419	144,860	4,940,522	285,374	918,564	986,572		94,414	
Distribution Plant											
(360) Land and Land Rights		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(361) Structures and Improvements		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(362) Station Equipment		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(364) Poles, Towers & Fixtures		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(365) Overhead Conductors & Devices		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(366) Underground Conduit		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(367) Underground Conductors & Device		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(368) Line Transformers		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(369) Services		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(370) Meters		200,512,098									MTR
- Demand	DMD-MTR	30,745,667	13,982,060	1,489,551	15,134,683	139,373	-	-		-	15%
- Customer	CUST-MTR	169,766,432	129,597,514	1,741,421	16,284,196	359,194	10,996,438	10,671,272		-	85%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		200,512,098	143,579,575	3,230,972	31,418,880	498,567	10,996,438	10,671,272		-	
(371) Installation on Customers' Premises		27,149,890									DEM
- Demand	DMD-LTG	27,149,890	-	-	-	-	-	-		27,149,890	100%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		27,149,890	-	-	-	-	-	-		27,149,890	
(373) Street Lighting & Signal Systems		265,095,805									DEM
- Demand	DMD-LTG	265,095,805	-	-	-	-	-	-		265,095,805	100%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		265,095,805	-	-	-	-	-	-		265,095,805	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
(374) Asset Retirement Costs		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(375) Charging Stations		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
Total Distribution Plant		492,757,793									
- Demand		322,991,361	13,982,060	1,489,551	15,134,683	139,373	-	-		292,245,694	
- Customer		169,766,432	129,597,514	1,741,421	16,284,196	359,194	10,996,438	10,671,272		-	
- Commodity		-	-	-	-	-	-	-		-	
Total		492,757,793	143,579,575	3,230,972	31,418,880	498,567	10,996,438	10,671,272		292,245,694	
General Plant											
(389) Land and Land Rights		431,335									AE-ALL
- Demand	DMD-ALL	223,340	135,951	1,776	62,359	2,915	8,407	9,451		1,313	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	207,996	98,211	2,038	67,710	4,598	15,776	16,523		1,173	48%
Total		431,335	234,162	3,814	130,068	7,513	24,183	25,973		2,486	
(390) Structures and Improvements		30,492,179									AE-ALL
- Demand	DMD-ALL	15,788,440	9,610,715	125,549	4,408,284	206,101	594,334	668,090		92,823	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	14,703,739	6,942,771	144,052	4,786,568	325,011	1,115,213	1,168,028		82,891	48%
Total		30,492,179	16,553,487	269,600	9,194,852	531,112	1,709,548	1,836,118		175,714	
(391) Office Furniture & Equipment		10,346,704									AE-ALL
- Demand	DMD-ALL	5,357,384	3,261,139	42,602	1,495,833	69,935	201,671	226,699		31,497	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	4,989,320	2,355,843	48,880	1,624,193	110,284	378,418	396,339		28,127	48%
Total		10,346,704	5,616,982	91,482	3,120,027	180,219	580,089	623,037		59,624	
(392) Transportation Equipment		5,024,096									AE-ALL
- Demand	DMD-ALL	2,601,409	1,583,526	20,686	726,338	33,959	97,926	110,079		15,294	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	2,422,686	1,143,937	23,735	788,667	53,551	183,750	192,452		13,658	48%
Total		5,024,096	2,727,463	44,421	1,515,005	87,510	281,677	302,531		28,952	
(393) Stores Equipment		322,950									AE-ALL
- Demand	DMD-ALL	167,219	101,789	1,330	46,689	2,183	6,295	7,076		983	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	155,731	73,533	1,526	50,696	3,442	11,812	12,371		878	48%
Total		322,950	175,322	2,855	97,385	5,625	18,106	19,447		1,861	
(394) Tools, Shop & Garage Equipment		6,961,084									AE-ALL
- Demand	DMD-ALL	3,604,355	2,194,038	28,662	1,006,371	47,051	135,681	152,519		21,191	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	3,356,728	1,584,971	32,886	1,092,729	74,197	254,593	266,650		18,923	48%
Total		6,961,084	3,779,008	61,547	2,099,100	121,248	390,274	419,169		40,114	
(395) Laboratory Equipment		123,099									AE-ALL
- Demand	DMD-ALL	63,739	38,799	507	17,797	832	2,399	2,697		375	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	59,360	28,028	582	19,324	1,312	4,502	4,715		335	48%
Total		123,099	66,828	1,088	37,120	2,144	6,902	7,413		709	
(396) Power Operated Equipment		590,436									AE-ALL
- Demand	DMD-ALL	305,720	186,097	2,431	85,360	3,991	11,508	12,937		1,797	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	284,716	134,437	2,789	92,685	6,293	21,594	22,617		1,605	48%
Total		590,436	320,534	5,220	178,045	10,284	33,103	35,554		3,402	
(397) Communication Equipment		18,782,145									AE-ALL
- Demand	DMD-ALL	9,725,142	5,919,874	77,334	2,715,353	126,951	366,090	411,521		57,176	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	9,057,003	4,276,511	88,731	2,948,363	200,196	686,934	719,465		51,058	48%
Total		18,782,145	10,196,384	166,065	5,663,716	327,147	1,053,023	1,130,986		108,234	
(398) Misc. Equipment		50,617									AE-ALL
- Demand	DMD-ALL	26,209	15,954	208	7,318	342	987	1,109		154	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	24,408	11,525	239	7,946	540	1,851	1,939		138	48%
Total		50,617	27,479	448	15,264	882	2,838	3,048		292	
(399) Other Tangible Property		420,880									AE-ALL
- Demand	DMD-ALL	217,926	132,656	1,733	60,847	2,845	8,204	9,222		1,281	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	202,954	95,830	1,988	66,068	4,486	15,393	16,122		1,144	48%
Total		420,880	228,486	3,721	126,916	7,331	23,597	25,344		2,425	
(SRVCO-PIS) Service Company PIS		40,249,742									AE-ALL
- Demand	DMD-ALL	20,840,775	12,686,165	165,724	5,818,944	272,054	784,523	881,881		122,527	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	19,408,967	9,164,473	190,149	6,318,280	429,015	1,472,084	1,541,799		109,416	48%
Total		40,249,742	21,850,638	355,873	12,137,224	701,069	2,256,607	2,423,680		231,943	
Total General Plant		113,795,268									
- Demand		58,921,659	35,866,702	468,541	16,451,493	769,160	2,218,025	2,493,279		346,412	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		54,873,609	25,910,071	537,594	17,863,229	1,212,924	4,161,920	4,359,020		309,344	
Total		113,795,268	61,776,773	1,006,135	34,314,721	1,982,084	6,379,945	6,852,300		655,756	
Total Utility Plant		622,936,932									
- Demand		390,396,368	55,012,733	2,025,551	33,954,808	1,019,274	2,537,369	2,852,253		292,641,981	
- Customer		169,766,432	129,597,514	1,741,421	16,284,196	359,194	10,996,438	10,671,272		-	
- Commodity		62,774,133	29,640,518	614,995	20,435,118	1,387,557	4,761,140	4,986,618		353,883	
Total		622,936,932	214,250,766	4,381,967	70,674,123	2,766,025	18,294,947	18,510,143		292,995,864	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	Lighting LTG	Classification Factor
Additions to Utility Plant										
Construction Work in Progress		-								
- Demand		-	-	-	-	-	-	-	-	
- Customer		-	-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	-	
Total		-	-	-	-	-	-	-	-	
Total Additional to Utility Plant		-								
- Demand		-	-	-	-	-	-	-	-	
- Customer		-	-	-	-	-	-	-	-	
- Commodity		-	-	-	-	-	-	-	-	
Total		-	-	-	-	-	-	-	-	
Total Utility Plant		622,936,932								
- Demand		390,396,368	55,012,733	2,025,551	33,954,808	1,019,274	2,537,369	2,852,253	292,641,981	
- Customer		169,766,432	129,597,514	1,741,421	16,284,196	359,194	10,996,438	10,671,272	-	
- Commodity		62,774,133	29,640,518	614,995	20,435,118	1,387,557	4,761,140	4,986,618	353,883	
Total		**622,936,932**	**214,250,766**	**4,381,967**	**70,674,123**	**2,766,025**	**18,294,947**	**18,510,143**	**292,995,864**	
ACCUMULATED DEPRECIATION										
Accumulated Depreciation										
(108-303) Misc Intangible Plant		(11,957,177)								AE-ALL
- Demand	DMD-ALL	(6,191,265)	(3,768,738)	(49,233)	(1,728,661)	(80,820)	(233,062)	(261,984)	(36,400)	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	(5,765,912)	(2,722,532)	(56,488)	(1,877,001)	(127,449)	(437,319)	(458,029)	(32,505)	48%
Total		(11,957,177)	(6,491,270)	(105,721)	(3,605,661)	(208,270)	(670,381)	(720,014)	(68,904)	
(108-360) Land & Land Rights		-								#N/A
- Demand		-	-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	-	
(108-361) Struct & Impmnts		-								#N/A
- Demand		-	-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	-	
(108-362) Station Equip		-								#N/A
- Demand		-	-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	-	
(108-364) Poles, Towers & Fixt		-								#N/A
- Demand		-	-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	-	
(108-365) OH Cond & Dev		-								#N/A
- Demand		-	-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	-	
(108-366) UG Conduit		-								#N/A
- Demand		-	-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	-	
(108-367) UG Cond & Dev		-								#N/A
- Demand		-	-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	-	
(108-368) Line Transformers		-								#N/A
- Demand		-	-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	-	
(108-369) Services		-								#N/A
- Demand		-	-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	-	
(108-370) Meters		(67,885,351)								MTR
- Demand	DMD-MTR	(10,409,249)	(4,733,765)	(504,302)	(5,123,996)	(47,186)	-	-	-	15%
- Customer	CUST-MTR	(57,476,102)	(43,876,518)	(589,575)	(5,513,175)	(121,609)	(3,722,953)	(3,612,864)	-	85%
- Commodity		-	-	-	-	-	-	-	-	0%
Total		(67,885,351)	(48,610,283)	(1,093,877)	(10,637,172)	(168,795)	(3,722,953)	(3,612,864)	-	
(108-371) Install on Cust Premise		(10,069,793)								DEM
- Demand	DMD-LTG	(10,069,793)	-	-	-	-	-	-	(10,069,793)	100%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	-	0%
Total		(10,069,793)	-	-	-	-	-	-	(10,069,793)	
(108-373) St Lt & Signal Sys		(99,523,237)								DEM
- Demand	DMD-LTG	(99,523,237)	-	-	-	-	-	-	(99,523,237)	100%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	-	0%
Total		(99,523,237)	-	-	-	-	-	-	(99,523,237)	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
(108-374) Asset Ret Costs		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(108-389) Land & Land Rights		(649)									AE-ALL
- Demand	DMD-ALL	(336)	(205)	(3)	(94)	(4)	(13)	(14)		(2)	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(313)	(148)	(3)	(102)	(7)	(24)	(25)		(2)	48%
Total		(649)	(352)	(6)	(196)	(11)	(36)	(39)		(4)	
(108-390) Struct & Impmnts -		(5,272,594)									AE-ALL
- Demand	DMD-ALL	(2,730,078)	(1,661,849)	(21,709)	(762,264)	(35,638)	(102,770)	(115,524)		(16,051)	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(2,542,516)	(1,200,518)	(24,909)	(827,675)	(56,200)	(192,839)	(201,971)		(14,333)	48%
Total		(5,272,594)	(2,862,367)	(46,618)	(1,589,939)	(91,838)	(295,609)	(317,495)		(30,384)	
(108-391) Office Furn & Equip		(588,664)									AE-ALL
- Demand	DMD-ALL	(304,802)	(185,539)	(2,424)	(85,104)	(3,979)	(11,474)	(12,898)		(1,792)	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(283,862)	(134,033)	(2,781)	(92,407)	(6,274)	(21,530)	(22,549)		(1,600)	48%
Total		(588,664)	(319,572)	(5,205)	(177,510)	(10,253)	(33,004)	(35,447)		(3,392)	
(108-392) Transportation Equip		(485,586)									AE-ALL
- Demand	DMD-ALL	(251,430)	(153,050)	(1,999)	(70,202)	(3,282)	(9,465)	(10,639)		(1,478)	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(234,156)	(110,563)	(2,294)	(76,226)	(5,176)	(17,760)	(18,601)		(1,320)	48%
Total		(485,586)	(263,613)	(4,293)	(146,427)	(8,458)	(27,224)	(29,240)		(2,798)	
(108-393) Stores Equip		(89,984)									AE-ALL
- Demand	DMD-ALL	(46,593)	(28,362)	(371)	(13,009)	(608)	(1,754)	(1,972)		(274)	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(43,392)	(20,489)	(425)	(14,125)	(959)	(3,291)	(3,447)		(245)	48%
Total		(89,984)	(48,850)	(796)	(27,135)	(1,567)	(5,045)	(5,419)		(519)	
(108-394) Tools, Shop & Garage Equip		(1,006,037)									AE-ALL
- Demand	DMD-ALL	(520,912)	(317,089)	(4,142)	(145,444)	(6,800)	(19,609)	(22,042)		(3,063)	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(485,125)	(229,065)	(4,753)	(157,925)	(10,723)	(36,795)	(38,537)		(2,735)	48%
Total		(1,006,037)	(546,154)	(8,895)	(303,368)	(17,523)	(56,404)	(60,580)		(5,797)	
(108-395) Laboratory Equip		(39,345)									AE-ALL
- Demand	DMD-ALL	(20,372)	(12,401)	(162)	(5,688)	(266)	(767)	(862)		(120)	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(18,973)	(8,958)	(186)	(6,176)	(419)	(1,439)	(1,507)		(107)	48%
Total		(39,345)	(21,359)	(348)	(11,864)	(685)	(2,206)	(2,369)		(227)	
(108-396) Power Operated Equip		(112,921)									AE-ALL
- Demand	DMD-ALL	(58,469)	(35,591)	(465)	(16,325)	(763)	(2,201)	(2,474)		(344)	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(54,452)	(25,711)	(533)	(17,726)	(1,204)	(4,130)	(4,326)		(307)	48%
Total		(112,921)	(61,302)	(998)	(34,051)	(1,967)	(6,331)	(6,800)		(651)	
(108-397) Communication Equip		(1,230,582)									AE-ALL
- Demand	DMD-ALL	(637,179)	(387,862)	(5,067)	(177,906)	(8,318)	(23,986)	(26,962)		(3,746)	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(593,403)	(280,191)	(5,814)	(193,173)	(13,117)	(45,007)	(47,138)		(3,345)	48%
Total		(1,230,582)	(668,054)	(10,880)	(371,079)	(21,434)	(68,993)	(74,101)		(7,091)	
(108-398) MISC Equip		(20,143)									AE-ALL
- Demand	DMD-ALL	(10,430)	(6,349)	(83)	(2,912)	(136)	(393)	(441)		(61)	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(9,713)	(4,586)	(95)	(3,162)	(215)	(737)	(772)		(55)	48%
Total		(20,143)	(10,935)	(178)	(6,074)	(351)	(1,129)	(1,213)		(116)	
(108-399) Other Tangible Property		-									AE-ALL
- Demand	DMD-ALL	-	-	-	-	-	-	-		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	-	-	-	-	-	-	-		-	48%
Total		-	-	-	-	-	-	-		-	
Service Company PIS		(9,181,627)									AE-ALL
- Demand	DMD-ALL	(4,754,123)	(2,893,922)	(37,804)	(1,327,397)	(62,060)	(178,962)	(201,171)		(27,950)	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(4,427,504)	(2,090,567)	(43,376)	(1,441,303)	(97,865)	(335,807)	(351,710)		(24,960)	48%
Total		(9,181,627)	(4,984,489)	(81,181)	(2,768,700)	(159,925)	(514,769)	(552,881)		(52,910)	
Total Accumulated Depreciation		(207,463,688)									
- Demand		(135,528,268)	(14,184,721)	(627,764)	(9,459,002)	(249,861)	(584,455)	(656,985)		(109,684,310)	
- Customer		(57,476,102)	(43,876,518)	(589,575)	(5,513,175)	(121,609)	(3,722,953)	(3,612,864)		-	
- Commodity		(14,459,319)	(6,827,362)	(141,657)	(4,707,001)	(319,608)	(1,096,675)	(1,148,612)		(81,513)	
Total Accumulated Depreciation		**(207,463,688)**	**(64,888,601)**	**(1,358,996)**	**(19,679,178)**	**(691,078)**	**(5,404,083)**	**(5,418,461)**		**(109,765,823)**	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG	Classification Factor
OTHER RATE BASE ITEMS											
Other Rate Base Items											
Materials and Supplies		2,690,264									DISTPLT-CS
- Demand	DISTPLT-CS-D	1,763,406	76,337	8,132	82,629	761	-	-		1,595,547	66%
- Customer	DISTPLT-CS-C	926,858	707,552	9,507	88,905	1,961	60,036	58,261		-	34%
- Commodity	DISTPLT-CS-E	-	-	-	-	-	-	-		-	0%
Total		2,690,264	783,888	17,640	171,535	2,722	60,036	58,261		1,595,547	
Cash Working Capital		31,703,994									CWC-CS
- Demand	CWC-CS-D	3,796,835	339,881	36,208	367,899	3,388	0	-		3,049,460	12%
- Customer	CWC-CS-C	27,813,625	23,800,742	334,598	3,061,629	12,588	279,609	262,941		58,668	88%
- Commodity	CWC-CS-E	93,534	44,165	916	30,449	2,067	7,094	7,430		527	0%
Total		31,703,994	24,184,787	371,723	3,459,977	18,043	286,704	270,371		3,108,655	
ADIT		(122,976,343)									DISTPLT-CS
- Demand	DISTPLT-CS-D	(80,608,155)	(3,489,468)	(371,743)	(3,777,125)	(34,783)	-	-		(72,935,035)	66%
- Customer	DISTPLT-CS-C	(42,368,188)	(32,343,331)	(434,602)	(4,064,007)	(89,643)	(2,744,354)	(2,663,203)		-	34%
- Commodity	DISTPLT-CS-E	-	-	-	-	-	-	-		-	0%
Total		(122,976,343)	(35,832,799)	(806,346)	(7,841,132)	(124,426)	(2,744,354)	(2,663,203)		(72,935,035)	
Net /Loss on Reacq Debt		140,919									DISTPLT-CS
- Demand	DISTPLT-CS-D	92,369	3,999	426	4,328	40	-	-		83,576	66%
- Customer	DISTPLT-CS-C	48,550	37,062	498	4,657	103	3,145	3,052		-	34%
- Commodity	DISTPLT-CS-E	-	-	-	-	-	-	-		-	0%
Total		140,919	41,061	924	8,985	143	3,145	3,052		83,576	
DTA for AMT		977,993									DISTPLT-CS
- Demand	DISTPLT-CS-D	641,052	27,751	2,956	30,038	277	-	-		580,030	66%
- Customer	DISTPLT-CS-C	336,941	257,217	3,456	32,320	713	21,825	21,180		-	34%
- Commodity	DISTPLT-CS-E	-	-	-	-	-	-	-		-	0%
Total		977,993	284,967	6,413	62,358	990	21,825	21,180		580,030	
Net Operating Reserves		(960,990)									PAY-CS
- Demand	PAY-CS-D	(216,018)	(91,035)	(1,905)	(46,534)	(1,864)	(5,156)	-		(69,524)	22%
- Customer	PAY-CS-C	(627,256)	(536,342)	(7,540)	(68,993)	(284)	(6,301)	(6,410)		(1,322)	65%
- Commodity	PAY-CS-E	(117,716)	(60,910)	(1,264)	(41,993)	(2,851)	(9,784)	(167)		(727)	12%
Total		(960,990)	(688,287)	(10,709)	(157,520)	(4,999)	(21,241)	(6,578)		(71,573)	
NOL		3,709,005									DISTPLT-CS
- Demand	DISTPLT-CS-D	2,431,167	105,243	11,212	113,919	1,049	-	-		2,199,744	66%
- Customer	DISTPLT-CS-C	1,277,838	975,485	13,108	122,572	2,704	82,771	80,323		-	34%
- Commodity	DISTPLT-CS-E	-	-	-	-	-	-	-		-	0%
Total		3,709,005	1,080,728	24,320	236,491	3,753	82,771	80,323		2,199,744	
CTA		(99,089)									TOTPLT-CS
- Demand	TOTPLT-CS-D	(62,100)	(8,751)	(322)	(5,401)	(162)	(404)	(454)		(46,550)	62.6703%
- Customer	TOTPLT-CS-C	(27,004)	(20,615)	(277)	(2,590)	(57)	(1,749)	(1,697)		-	27%
- Commodity	TOTPLT-CS-E	(9,985)	(4,715)	(98)	(3,251)	(221)	(757)	(793)		(56)	10%
Total		(99,089)	(34,080)	(697)	(11,242)	(440)	(2,910)	(2,944)		(46,606)	
Regulatory Asset A&G Capitalization		5,643,328									AE-PRI-GTA&G
- Demand	DMD-PRI	2,986,054	1,908,398	24,930	875,352	40,926	118,017	-		18,432	53%
- Customer	CUST-GTA&G	11,100	-	-	-	-	-	11,100		-	0%
- Commodity	NRG-PRI	2,646,175	1,371,386	28,454	945,478	64,198	220,285	-		16,373	47%
Total		5,643,328	3,279,784	53,384	1,820,829	105,124	338,302	11,100		34,805	
Customer Deposits		(36,962,658)									CUS
- Demand		-	-	-	-	-	-	-		-	0%
- Customer	CUST-DEP	(36,962,658)	(32,304,391)	(457,206)	(4,170,208)	(6,033)	(19,249)	(5,538)		-	100%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		(36,962,658)	(32,304,391)	(457,206)	(4,170,208)	(6,033)	(19,249)	(5,538)		-	
Customer Advances		(5,120,290)									DISTPLT-CS
- Demand	DISTPLT-CS-D	(3,356,232)	(145,289)	(15,478)	(157,266)	(1,448)	-	-		(3,036,751)	66%
- Customer	DISTPLT-CS-C	(1,764,058)	(1,346,659)	(18,095)	(169,211)	(3,732)	(114,265)	(110,886)		-	34%
- Commodity	DISTPLT-CS-E	-	-	-	-	-	-	-		-	0%
Total		(5,120,290)	(1,491,948)	(33,573)	(326,476)	(5,181)	(114,265)	(110,886)		(3,036,751)	
Customer Refunds		(28,575)									DISTPLT-CS
- Demand	DISTPLT-CS-D	(18,730)	(811)	(86)	(878)	(8)	-	-		(16,947)	66%
- Customer	DISTPLT-CS-C	(9,845)	(7,515)	(101)	(944)	(21)	(638)	(619)		-	34%
- Commodity	DISTPLT-CS-E	-	-	-	-	-	-	-		-	0%
Total		(28,575)	(8,326)	(187)	(1,822)	(29)	(638)	(619)		(16,947)	
Total Other Rate Base Items		(121,282,442)									
- Demand		(72,550,351)	(1,273,746)	(305,670)	(2,513,038)	8,174	112,457	(454)		(68,578,019)	
- Customer		(51,344,098)	(40,780,797)	(556,654)	(5,165,870)	(81,702)	(2,439,169)	(2,351,498)		57,346	
- Commodity		2,612,008	1,349,927	28,009	930,683	63,194	216,838	6,469		16,117	
Total		(121,282,442)	(40,704,616)	(834,315)	(6,748,225)	(10,334)	(2,109,874)	(2,345,482)		(68,504,556)	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
Rate Base Adjustment											
Adjustment											
AMI		43,720,862									MTR
- Demand	DMD-MTR	6,703,970	3,048,732	324,791	3,300,057	30,390	-	-		-	15%
- Customer	CUST-MTR	37,016,892	28,258,220	379,710	3,550,704	78,321	2,397,729	2,326,828		-	85%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		43,720,862	31,306,952	704,500	6,850,761	108,711	2,397,729	2,326,828		-	
Delayed Recognition Pension & OPEB		(10,398,169)									PAY-CS
- Demand	PAY-CS-D	(2,337,371)	(985,022)	(20,614)	(503,506)	(20,173)	(55,790)	-		(752,267)	22%
- Customer	PAY-CS-C	(6,787,078)	(5,803,364)	(81,585)	(746,521)	(3,069)	(68,178)	(69,360)		(14,305)	65%
- Commodity	PAY-CS-E	(1,273,721)	(659,058)	(13,674)	(454,376)	(30,852)	(105,864)	(1,812)		(7,869)	12%
Total		(10,398,169)	(7,447,444)	(115,874)	(1,704,403)	(54,094)	(229,831)	(71,172)		(774,440)	
Total Rate Base Adjustment		33,322,692									
- Demand		4,366,599	2,063,711	304,177	2,796,551	10,217	(55,790)	-		(752,267)	
- Customer		30,229,814	22,454,856	298,125	2,804,183	75,252	2,329,552	2,257,468		(14,305)	
- Commodity		(1,273,721)	(659,058)	(13,674)	(454,376)	(30,852)	(105,864)	(1,812)		(7,869)	
Total		33,322,692	23,859,508	588,627	5,146,358	54,616	2,167,898	2,255,656		(774,440)	
Total Rate Base		**327,513,495**									
- Demand		**186,684,349**	**41,617,977**	**1,396,294**	**24,779,320**	**787,804**	**2,009,582**	**2,194,815**		**113,627,386**	
- Customer		**91,176,046**	**67,395,055**	**893,316**	**8,409,334**	**231,135**	**7,163,868**	**6,964,377**		**43,041**	
- Commodity		**49,653,101**	**23,504,026**	**487,672**	**16,204,424**	**1,100,290**	**3,775,438**	**3,842,664**		**280,618**	
Total		**327,513,495**	**132,517,058**	**2,777,282**	**49,393,078**	**2,119,229**	**12,948,888**	**13,001,856**		**113,951,045**	
OPERATIONS & MAINTENANCE EXPENSES											
Distribution Expenses											
Operations Expenses											
(580) Operation Supervision & Engineering		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(581) Load Dispatching		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(582) Station Expenses		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(583) Overhead line expenses		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(584) Underground line expenses		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(585) Street lighting and signal system expenses		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(586) Meter expenses		3,863,627									MTR
- Demand	DMD-MTR	592,432	269,417	28,702	291,627	2,686	-	-		-	15%
- Customer	CUST-MTR	3,271,195	2,497,188	33,555	313,777	6,921	211,888	205,623		-	85%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		3,863,627	2,766,606	62,257	605,404	9,607	211,888	205,623		-	
(587) Customer installations expenses		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(588) Miscellaneous distribution expenses		2,182,355									DISTPLT-CS
- Demand	DISTPLT-CS-D	1,430,484	61,925	6,597	67,029	617	-	-		1,294,315	66%
- Customer	DISTPLT-CS-C	751,872	573,969	7,713	72,120	1,591	48,702	47,262		-	34%
- Commodity	DISTPLT-CS-E	-	-	-	-	-	-	-		-	0%
Total		2,182,355	635,894	14,310	139,150	2,208	48,702	47,262		1,294,315	
(589) Rents		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
Total Dist. Operations Expenses		6,045,983									
- Demand		2,022,916	331,342	35,299	358,657	3,303	-	-		1,294,315	
- Customer		4,023,067	3,071,158	41,268	385,897	8,512	260,590	252,884		-	
- Commodity		-	-	-	-	-	-	-		-	
Total		6,045,983	3,402,500	76,566	744,554	11,815	260,590	252,884		1,294,315	
Maintenance Expense											
(590) Maintenance Supervision and Engineering		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
(591) Maintenance of Structures		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(592) Maintenance of Station Equipment		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(593) Maintenance of Overhead Lines		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(594) Maintenance of underground lines		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(595) Maintenance of line transformers		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(596) Maintenance of street lighting and signal systems		4,146,141									DEM
- Demand	DMD-LTG	4,146,141	-	-	-	-	-	-		4,146,141	100%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		4,146,141	-	-	-	-	-	-		4,146,141	
(597) Maintenance of meters		4,075,777									MTR
- Demand	DMD-MTR	624,962	284,211	30,278	307,640	2,833	-	-		-	15%
- Customer	CUST-MTR	3,450,815	2,634,308	35,398	331,006	7,301	223,523	216,913		-	85%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		4,075,777	2,918,519	65,675	638,646	10,134	223,523	216,913		-	
(598) Maintenance of miscellaneous distribution plant		243,395									DISTPLT-CS
- Demand	DISTPLT-CS-D	159,540	6,906	736	7,476	69	-	-		144,353	66%
- Customer	DISTPLT-CS-C	83,855	64,014	860	8,043	177	5,432	5,271		-	34%
- Commodity	DISTPLT-CS-E	-	-	-	-	-	-	-		-	0%
Total		243,395	70,920	1,596	15,519	246	5,432	5,271		144,353	
Total Dist. Maintenance Expenses		8,465,313									
- Demand		4,930,643	291,117	31,014	315,116	2,902	-	-		4,290,494	
- Customer		3,534,670	2,698,322	36,258	339,050	7,479	228,954	222,184		-	
- Commodity		-	-	-	-	-	-	-		-	
Total		8,465,313	2,989,439	67,271	654,166	10,381	228,954	222,184		4,290,494	
Total Distribution Expenses		14,511,296									
- Demand		6,953,559	622,460	66,312	673,773	6,205	-	-		5,584,810	
- Customer		7,557,737	5,769,479	77,525	724,947	15,991	489,544	475,068		-	
- Commodity		-	-	-	-	-	-	-		-	
Total		14,511,296	6,391,939	143,838	1,398,720	22,195	489,544	475,068		5,584,810	
Customer Account Expense											
(901) Supervision		42,924									CUS
- Demand		-	-	-	-	-	-	-		-	0%
- Customer	CUST-ALL	42,924	37,422	530	4,831	7	22	6		106	100%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		42,924	37,422	530	4,831	7	22	6		106	
(902) Meter reading expenses		15,227,521									CUS
- Demand		-	-	-	-	-	-	-		-	0%
- Customer	CUST-ALL	15,227,521	13,275,491	187,889	1,713,747	2,479	7,910	2,276		37,716	100%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		15,227,521	13,275,491	187,889	1,713,747	2,479	7,910	2,276		37,716	
(903) Customer records and collection expenses		16,190,497									CUS
- Demand		-	-	-	-	-	-	-		-	0%
- Customer	CUST-ALL	16,190,497	14,115,022	199,771	1,822,123	2,636	8,411	2,420		40,101	100%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		16,190,497	14,115,022	199,771	1,822,123	2,636	8,411	2,420		40,101	
(904) Uncollectible accounts		171,298									COM
- Demand		-	-	-	-	-	-	-		-	0%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	171,298	80,883	1,678	55,763	3,786	12,992	13,607		966	100%
Total		171,298	80,883	1,678	55,763	3,786	12,992	13,607		966	
(905) Miscellaneous customer accounts expenses		1,439,425									CUS
- Demand		-	-	-	-	-	-	-		-	0%
- Customer	CUST-ALL	1,439,425	1,254,904	17,761	161,997	234	748	215		3,565	100%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		1,439,425	1,254,904	17,761	161,997	234	748	215		3,565	
Total Customer Account Expenses		33,071,665									
- Demand		-	-	-	-	-	-	-		-	
- Customer		32,900,367	28,682,837	405,950	3,702,698	5,357	17,091	4,917		81,488	
- Commodity		171,298	80,883	1,678	55,763	3,786	12,992	13,607		966	
Total		33,071,665	28,763,720	407,628	3,758,461	9,143	30,083	18,525		82,454	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
Customer Service Expenses											
(907) Customer Service Supervision		46,097									CUS
- Demand		-	-	-	-	-	-	-		-	0%
- Customer	CUST-ALL	46,097	40,188	569	5,188	8	24	7		114	100%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		46,097	40,188	569	5,188	8	24	7		114	
(908) Customer Assistance		2,080,009									CUS
- Demand		-	-	-	-	-	-	-		-	0%
- Customer	CUST-ALL	2,080,009	1,813,371	25,665	234,090	339	1,081	311		5,152	100%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		2,080,009	1,813,371	25,665	234,090	339	1,081	311		5,152	
(909) Informational and instructional advertising		2,645									CUS
- Demand		-	-	-	-	-	-	-		-	0%
- Customer	CUST-ALL	2,645	2,306	33	298	0	1	0		7	100%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		2,645	2,306	33	298	0	1	0		7	
(910) Miscellaneous customer service and informational		8,351,286									CUS
- Demand		-	-	-	-	-	-	-		-	0%
- Customer	CUST-ALL	8,351,286	7,280,727	103,045	939,877	1,360	4,338	1,248		20,685	100%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		8,351,286	7,280,727	103,045	939,877	1,360	4,338	1,248		20,685	
Total Customer Service Expenses		10,480,037									
- Demand		-	-	-	-	-	-	-		-	
- Customer		10,480,037	9,136,591	129,311	1,179,452	1,706	5,444	1,566		25,957	
- Commodity		-	-	-	-	-	-	-		-	
Total		10,480,037	9,136,591	129,311	1,179,452	1,706	5,444	1,566		25,957	
Sales Expenses											
(911) Sales Exp		4									AE-PRI
- Demand	DMD-PRI	2	1	0	1	0	0	-		0	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-PRI	2	1	0	1	0	0	-		0	47%
Total		4	2	0	1	0	0	-		0	
Total Sales Expenses		4									
- Demand		2	1	0	1	0	0	-		0	
- Customer		-	-	-	-	-	-	-		-	
- Commodity		2	1	0	1	0	0	-		0	
Total		4	2	0	1	0	0	-		0	
Administrative & General Expense											
Labor Related											
(920) Administrative and general salaries		3,982,779									AE-PRI-GTA&G
- Demand	DMD-PRI	2,107,407	1,346,851	17,594	617,780	28,883	83,290	-		13,008	53%
- Customer	CUST-GTA&G	7,834	-	-	-	-	-	7,834		-	0%
- Commodity	NRG-PRI	1,867,538	967,856	20,082	667,271	45,308	155,466	-		11,555	47%
Total		3,982,779	2,314,707	37,676	1,285,050	74,191	238,757	7,834		24,564	
(921) Office supplies and expenses		356,264									AE-PRI-GTA&G
- Demand	DMD-PRI	188,510	120,477	1,574	55,261	2,584	7,450	-		1,164	53%
- Customer	CUST-GTA&G	701	-	-	-	-	-	701		-	0%
- Commodity	NRG-PRI	167,053	86,576	1,796	59,688	4,053	13,907	-		1,034	47%
Total		356,264	207,053	3,370	114,949	6,636	21,357	701		2,197	
(922) Administrative expenses transferred—Credit		(354,702)									AE-PRI-GTA&G
- Demand	DMD-PRI	(187,684)	(119,949)	(1,567)	(55,019)	(2,572)	(7,418)	-		(1,159)	53%
- Customer	CUST-GTA&G	(698)	-	-	-	-	-	(698)		-	0%
- Commodity	NRG-PRI	(166,321)	(86,196)	(1,788)	(59,426)	(4,035)	(13,846)	-		(1,029)	47%
Total		(354,702)	(206,145)	(3,355)	(114,445)	(6,607)	(21,263)	(698)		(2,188)	
(923) Outside services employed		12,972,666									AE-PRI-GTA&G
- Demand	DMD-PRI	6,864,225	4,386,951	57,309	2,012,225	94,078	271,293	-		42,371	53%
- Customer	CUST-GTA&G	25,515	-	-	-	-	-	25,515		-	0%
- Commodity	NRG-PRI	6,082,925	3,152,490	65,409	2,173,427	147,577	506,383	-		37,638	47%
Total		12,972,666	7,539,441	122,718	4,185,653	241,655	777,675	25,515		80,009	
(926) Employee pensions and benefits		(800,946)									AE-PRI-GTA&G
- Demand	DMD-PRI	(423,805)	(270,855)	(3,538)	(124,237)	(5,808)	(16,750)	-		(2,616)	53%
- Customer	CUST-GTA&G	(1,575)	-	-	-	-	-	(1,575)		-	0%
- Commodity	NRG-PRI	(375,566)	(194,638)	(4,038)	(134,190)	(9,112)	(31,265)	-		(2,324)	47%
Total		(800,946)	(465,493)	(7,577)	(258,427)	(14,920)	(48,014)	(1,575)		(4,940)	
(426) Pension / OPEB Non-Service Cost		-									AE-PRI-GTA&G
- Demand		-	-	-	-	-	-	-		-	53%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity		-	-	-	-	-	-	-		-	47%
Total		-	-	-	-	-	-	-		-	
(924) Property insurance		24,708									AE-PRI-GTA&G
- Demand	DMD-PRI	13,074	8,355	109	3,832	179	517	-		81	53%
- Customer	CUST-GTA&G	49	-	-	-	-	-	49		-	0%
- Commodity	NRG-PRI	11,586	6,004	125	4,140	281	964	-		72	47%
Total		24,708	14,360	234	7,972	460	1,481	49		152	
(925) Injuries and damages		451,258									AE-PRI-GTA&G
- Demand	DMD-PRI	238,774	152,601	1,993	69,996	3,273	9,437	-		1,474	53%
- Customer	CUST-GTA&G	888	-	-	-	-	-	888		-	0%
- Commodity	NRG-PRI	211,596	109,660	2,275	75,603	5,134	17,615	-		1,309	47%
Total		451,258	262,261	4,269	145,599	8,406	27,052	888		2,783	
(935) Maintenance of general plant		403,631									AE-PRI-GTA&G
- Demand	DMD-PRI	213,573	136,495	1,783	62,608	2,927	8,441	-		1,318	53%
- Customer	CUST-GTA&G	794	-	-	-	-	-	794		-	0%
- Commodity	NRG-PRI	189,264	98,087	2,035	67,624	4,592	15,756	-		1,171	47%
Total		403,631	234,582	3,818	130,232	7,519	24,197	794		2,489	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	Lighting LTG	Classification Factor
(929) Duplicate charges—Credit		-								AE-PRI-GTA&G
- Demand		-	-	-	-	-	-	-	-	53%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity		-	-	-	-	-	-	-	-	47%
Total		-	-	-	-	-	-	-	-	
(928) Regulatory commission expenses		1,424,394								AE-PRI-GTA&G
- Demand	DMD-PRI	753,690	481,686	6,292	220,942	10,330	29,788	-	4,652	53%
- Customer	CUST-GTA&G	2,802	-	-	-	-	-	2,802	-	0%
- Commodity	NRG-PRI	667,903	346,142	7,182	238,642	16,204	55,601	-	4,133	47%
Total		1,424,394	827,828	13,474	459,583	26,534	85,388	2,802	8,785	
(930.1) Gen Advertising Exp		228,486								AE-PRI-GTA&G
- Demand	DMD-PRI	120,899	77,267	1,009	35,441	1,657	4,778	-	746	53%
- Customer	CUST-GTA&G	449	-	-	-	-	-	449	-	0%
- Commodity	NRG-PRI	107,138	55,524	1,152	38,280	2,599	8,919	-	663	47%
Total		228,486	132,791	2,161	73,721	4,256	13,697	449	1,409	
(930.2) Misc Gen Exp		715,398								AE-PRI-GTA&G
- Demand	DMD-PRI	378,538	241,925	3,160	110,967	5,188	14,961	-	2,337	53%
- Customer	CUST-GTA&G	1,407	-	-	-	-	-	1,407	-	0%
- Commodity	NRG-PRI	335,452	173,849	3,607	119,857	8,138	27,925	-	2,076	47%
Total		715,398	415,774	6,767	230,824	13,326	42,886	1,407	4,412	
(931) Rents		633,423								AE-PRI-GTA&G
- Demand	DMD-PRI	335,163	214,204	2,798	98,252	4,594	13,247	-	2,069	53%
- Customer	CUST-GTA&G	1,246	-	-	-	-	-	1,246	-	0%
- Commodity	NRG-PRI	297,014	153,928	3,194	106,123	7,206	24,725	-	1,838	47%
Total		633,423	368,132	5,992	204,375	11,799	37,972	1,246	3,907	
(932) Institutional Ad - Newspaper		-								#N/A
- Demand		-	-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	-	N/A
Total		-	-	-	-	-	-	-	-	
(933) Transportation expenses		-								#N/A
- Demand		-	-	-	-	-	-	-	-	N/A
- Customer		-	-	-	-	-	-	-	-	N/A
- Commodity		-	-	-	-	-	-	-	-	N/A
Total A&G Expense		20,037,357								
- Demand		10,602,365	6,776,009	88,518	3,108,049	145,311	419,034	-	65,445	
- Customer		39,411	-	-	-	-	-	39,411	-	
- Commodity		9,395,581	4,869,283	101,030	3,357,039	227,945	782,150	-	58,135	
Total		20,037,357	11,645,291	189,548	6,465,087	373,256	1,201,184	39,411	123,580	
O&M Adjustment										
Adjustment										
Int on Cust Deposits		517,477								CUS
- Demand		-	-	-	-	-	-	-	-	0%
- Customer	CUST-DEP	517,477	452,261	6,401	58,383	84	269	78	-	100%
- Commodity		-	-	-	-	-	-	-	-	0%
Total		517,477	452,261	6,401	58,383	84	269	78	-	
Annualize Payroll Increase		1,506,137								PAY-CS
- Demand	PAY-CS-D	338,560	142,677	2,986	72,931	2,922	8,081	-	108,963	22%
- Customer	PAY-CS-C	983,084	840,596	11,817	108,131	445	9,875	10,047	2,072	65%
- Commodity	PAY-CS-E	184,494	95,462	1,981	65,815	4,469	15,334	262	1,140	12%
Total		1,506,137	1,078,735	16,784	246,877	7,835	33,290	10,309	112,175	
Svngs Pln Match on Payroll Inc		45,184								PAY-CS
- Demand	PAY-CS-D	10,157	4,280	90	2,188	88	242	-	3,269	22%
- Customer	PAY-CS-C	29,492	25,218	355	3,244	13	296	301	62	65%
- Commodity	PAY-CS-E	5,535	2,864	59	1,974	134	460	8	34	12%
Total		45,184	32,362	504	7,406	235	999	309	3,365	
Reclass Amortization of Net Loss on Reacquired Debt		55,682								DISTPLT-CS
- Demand	DISTPLT-CS-D	36,498	1,580	168	1,710	16	-	-	33,024	66%
- Customer	DISTPLT-CS-C	19,184	14,645	197	1,840	41	1,243	1,206	-	34%
- Commodity	DISTPLT-CS-E	-	-	-	-	-	-	-	-	0%
Total		55,682	16,224	365	3,550	56	1,243	1,206	33,024	
BPU & RPA Assessments		92,421								DIST-REV
- Demand	DIST-REV-DMD	24,408	-	-	15,771	1,244	3,069	2,281	1,999	26%
- Customer	DIST-REV-CUST	7,442	5,308	162	1,823	15	60	74	-	8%
- Commodity	DIST-REV-NRG	60,572	44,989	832	12,288	306	789	597	770	66%
Total		92,421	50,297	994	29,882	1,566	3,918	2,951	2,769	
Rate Case Exp		-								AE-ALL
- Demand	DMD-ALL	-	-	-	-	-	-	-	-	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	-	-	-	-	-	-	-	-	48%
Total		-	-	-	-	-	-	-	-	
Pension Smoothing		4,118,496								PAY-CS
- Demand	PAY-CS-D	925,783	390,146	8,165	199,428	7,990	22,097	-	297,957	22%
- Customer	PAY-CS-C	2,688,218	2,298,590	32,314	295,681	1,216	27,004	27,472	5,666	65%
- Commodity	PAY-CS-E	504,494	261,039	5,416	179,969	12,220	41,931	718	3,117	12%
Total		4,118,496	2,949,776	45,895	675,078	21,426	91,031	28,190	306,740	
OPEB Smoothing		1,413,226								PAY-CS
- Demand	PAY-CS-D	317,674	133,875	2,802	68,432	2,742	7,582	-	102,241	22%
- Customer	PAY-CS-C	922,439	788,741	11,088	101,460	417	9,266	9,427	1,944	65%
- Commodity	PAY-CS-E	173,113	89,573	1,859	61,755	4,193	14,388	246	1,069	12%
Total		1,413,226	1,012,190	15,749	231,647	7,352	31,237	9,673	105,255	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
Normalize Vegetation Management Expense		-									OHPLT-CS
- Demand	OHPLT-CS-D	-	-	-	-	-	-	-		-	0%
- Customer	OHPLT-CS-C	-	-	-	-	-	-	-		-	0%
- Commodity	OHPLT-CS-E	-	-	-	-	-	-	-		-	0%
Total		-	-	-	-	-	-	-		-	
ServCo Depr @ JCP&L Rates		269,402									AE-ALL
- Demand	DMD-ALL	139,493	84,912	1,109	38,948	1,821	5,251	5,903		820	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	129,909	61,340	1,273	42,290	2,872	9,853	10,320		732	48%
Total		269,402	146,252	2,382	81,238	4,692	15,104	16,222		1,552	
SERP/EDCP		1,418,028									PAY-CS
- Demand	PAY-CS-D	318,754	134,330	2,811	68,665	2,751	7,608	-		102,589	22%
- Customer	PAY-CS-C	925,573	791,421	11,126	101,805	419	9,298	9,459		1,951	65%
- Commodity	PAY-CS-E	173,701	89,878	1,865	61,964	4,207	14,437	247		1,073	12%
Total		1,418,028	1,015,629	15,802	232,434	7,377	31,343	9,706		105,613	
BGS Administrative Labor included in BGS Deferral		-									AE-ALL
- Demand	DMD-ALL	-	-	-	-	-	-	-		-	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	-	-	-	-	-	-	-		-	48%
Total		-	-	-	-	-	-	-		-	
Low Income O&M		740,131									AE-ALL
- Demand	DMD-ALL	383,230	233,279	3,047	107,001	5,003	14,426	16,216		2,253	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	356,901	168,521	3,497	116,183	7,889	27,069	28,351		2,012	48%
Total		740,131	401,800	6,544	223,185	12,892	41,496	44,568		4,265	
Advertising removal		-									N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
Contract Labor/Fuel Costs		-									N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
Total O&M Adjustment		10,176,183									
- Demand		2,494,556	1,125,080	21,178	575,075	24,576	68,357	24,400		653,115	
- Customer		6,092,909	5,216,780	73,460	672,367	2,650	57,311	58,063		11,695	
- Commodity		1,588,718	813,666	16,781	542,238	36,290	124,261	40,749		9,947	
Total		10,176,183	7,155,526	111,419	1,789,680	63,516	249,929	123,212		674,757	
Total O&M Expenses		88,276,542									
- Demand		20,050,482	8,523,549	176,008	4,356,897	176,092	487,391	24,400		6,303,369	
- Customer		57,070,460	48,805,688	686,246	6,279,465	25,704	569,390	579,026		119,140	
- Commodity		11,155,599	5,763,833	119,489	3,955,040	268,022	919,404	54,357		69,048	
Total		**88,276,542**	**63,093,070**	**981,743**	**14,591,402**	**469,817**	**1,976,184**	**657,782**		**6,491,558**	
DEPRECIATION EXPENSE											
Depreciation Expense											
(403-360) Land & Land Rights		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(403-361) Struct & Impmnts		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(403-362) Station Equip		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(403-364) Poles, Towers & Fixt		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(403-365) OH Cond & Dev		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(403-366) UG Conduit		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(403-367) UG Cond & Dev		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT		Lighting LTG	Classification Factor
(403-368) Line Transformers		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(403-369) Services		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(403-370) Meters		10,227,000									MTR
- Demand	DMD-MTR	1,568,164	713,147	75,974	771,936	7,109	-	-		-	15%
- Customer	CUST-MTR	8,658,836	6,610,044	88,820	830,566	18,320	560,867	544,282		-	85%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		10,227,000	7,323,191	164,794	1,602,501	25,429	560,867	544,282		-	
(403-371) Install on Cust Premise		1,173,277									DEM
- Demand	DMD-LTG	1,173,277	-	-	-	-	-	-		1,173,277	100%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		1,173,277	-	-	-	-	-	-		1,173,277	
(403-373) St Lt & Signal Sys		8,028,829									DEM
- Demand	DMD-LTG	8,028,829	-	-	-	-	-	-		8,028,829	100%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity		-	-	-	-	-	-	-		-	0%
Total		8,028,829	-	-	-	-	-	-		8,028,829	
(403-374) Asset Ret Costs		-									#N/A
- Demand		-	-	-	-	-	-	-		-	N/A
- Customer		-	-	-	-	-	-	-		-	N/A
- Commodity		-	-	-	-	-	-	-		-	N/A
Total		-	-	-	-	-	-	-		-	
(403-389) Land & Land Rights		38									AE-ALL
- Demand	DMD-ALL	20	12	0	6	0	1	1		0	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	18	9	0	6	0	1	1		0	48%
Total		38	21	0	12	1	2	2		0	
(403-390) Struct & Impmnts -		121,381									AE-ALL
- Demand	DMD-ALL	62,849	38,258	500	17,548	820	2,366	2,659		370	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	58,531	27,637	573	19,054	1,294	4,439	4,650		330	48%
Total		121,381	65,895	1,073	36,602	2,114	6,805	7,309		699	
(403-391) Office Furn & Equip		599,114									AE-ALL
- Demand	DMD-ALL	310,213	188,832	2,467	86,614	4,050	11,678	13,127		1,824	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	288,901	136,412	2,830	94,047	6,386	21,912	22,950		1,629	48%
Total		599,114	325,245	5,297	180,661	10,435	33,589	36,076		3,452	
(403-392) Transportation Equip		139,127									AE-ALL
- Demand	DMD-ALL	72,038	43,851	573	20,114	940	2,712	3,048		424	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	67,089	31,678	657	21,840	1,483	5,088	5,329		378	48%
Total		139,127	75,529	1,230	41,954	2,423	7,800	8,378		802	
(403-393) Stores Equip		1,820									AE-ALL
- Demand	DMD-ALL	942	574	7	263	12	35	40		6	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	878	414	9	286	19	67	70		5	48%
Total		1,820	988	16	549	32	102	110		10	
(403-394) Tools, Shop & Garage Equip		83,569									AE-ALL
- Demand	DMD-ALL	43,271	26,340	344	12,082	565	1,629	1,831		254	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	40,298	19,028	395	13,118	891	3,056	3,201		227	48%
Total		83,569	45,368	739	25,200	1,456	4,685	5,032		482	
(403-395) Laboratory Equip		1,714									AE-ALL
- Demand	DMD-ALL	888	540	7	248	12	33	38		5	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	827	390	8	269	18	63	66		5	48%
Total		1,714	931	15	517	30	96	103		10	
(403-396) Power Operated Equip		5,228									AE-ALL
- Demand	DMD-ALL	2,707	1,648	22	756	35	102	115		16	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	2,521	1,190	25	821	56	191	200		14	48%
Total		5,228	2,838	46	1,577	91	293	315		30	
(403-397) Communication Equip		295,864									AE-ALL
- Demand	DMD-ALL	153,194	93,252	1,218	42,773	2,000	5,767	6,482		901	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	142,669	67,365	1,398	46,444	3,154	10,821	11,333		804	48%
Total		295,864	160,617	2,616	89,217	5,153	16,588	17,816		1,705	
(403-398) MISC Equip		(1,548)									AE-ALL
- Demand	DMD-ALL	(802)	(488)	(6)	(224)	(10)	(30)	(34)		(5)	52%
- Customer		-	-	-	-	-	-	-		-	0%
- Commodity	NRG-ALL	(747)	(353)	(7)	(243)	(17)	(57)	(59)		(4)	48%
Total		(1,548)	(841)	(14)	(467)	(27)	(87)	(93)		(9)	
Total Depreciation Expense		20,675,414									
- Demand		11,415,592	1,105,966	81,105	952,115	15,533	24,292	27,307		9,205,900	
- Customer		8,658,836	6,610,044	88,820	830,566	18,320	560,867	544,282		-	
- Commodity		600,986	283,772	5,888	195,641	13,284	45,582	47,741		3,388	
Total		20,675,414	7,999,782	175,813	1,978,323	47,137	630,741	619,330		9,209,288	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	Lighting LTG	Classification Factor
Depreciation Adjustment										
Adjustment										
Annualize Deprec Exp		1,378,574								DPR-TOT-CS
- Demand	DPR-TOT-CS-D	761,157	73,742	5,408	63,484	1,036	1,620	1,821	613,822	55%
- Customer	DPR-TOT-CS-C	577,345	440,738	5,922	55,380	1,222	37,397	36,291	-	42%
- Commodity	DPR-TOT-CS-E	40,072	18,921	393	13,045	886	3,039	3,183	226	3%
Total		1,378,574	533,401	11,723	131,909	3,143	42,056	41,295	614,048	
Average Net Salvage		387,212								DISTPLT-CS
- Demand	DISTPLT-CS-D	253,809	10,987	1,170	11,893	110	-	-	229,648	66%
- Customer	DISTPLT-CS-C	133,404	101,839	1,368	12,796	282	8,641	8,386	-	34%
- Commodity	DISTPLT-CS-E	-	-	-	-	-	-	-	-	0%
Total		387,212	112,826	2,539	24,689	392	8,641	8,386	229,648	
Total Depreciation Adjustment		1,765,786								
- Demand		1,014,966	84,730	6,578	75,377	1,145	1,620	1,821	843,470	
- Customer		710,749	542,576	7,291	68,176	1,504	46,038	44,677	-	
- Commodity		40,072	18,921	393	13,045	886	3,039	3,183	226	
Total		1,765,786	646,227	14,262	156,598	3,535	50,697	49,681	843,696	
Total Depreciation Expense										
- Demand		12,430,557	1,190,695	87,684	1,027,493	16,678	25,912	29,128	10,049,370	
- Customer		9,369,585	7,152,621	96,111	898,742	19,824	606,905	588,959	-	
- Commodity		641,058	302,693	6,280	208,686	14,170	48,621	50,924	3,614	
Total		**22,441,200**	**8,646,009**	**190,075**	**2,134,920**	**50,672**	**681,438**	**669,010**	**10,052,984**	
Amortization, Accretion, Regulatory Debits and Credits										
Amort - Ltd Term Elec Prpty		1,279,397								DISTPLT-CS
- Demand	DISTPLT-CS-D	838,615	36,303	3,867	39,296	362	-	-	758,787	66%
- Customer	DISTPLT-CS-C	440,782	336,487	4,521	42,280	933	28,551	27,707	-	34%
- Commodity	DISTPLT-CS-E	-	-	-	-	-	-	-	-	0%
Total		1,279,397	372,790	8,389	81,576	1,294	28,551	27,707	758,787	
Accretion Expense		41,510								AE-ALL
- Demand	DMD-ALL	21,493	13,083	171	6,001	281	809	909	126	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	20,017	9,451	196	6,516	442	1,518	1,590	113	48%
Total		41,510	22,535	367	12,517	723	2,327	2,500	239	
Regulatory Debits		6,729,898								AE-ALL
- Demand	DMD-ALL	3,484,651	2,121,171	27,710	972,948	45,488	131,175	147,454	20,487	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	3,245,247	1,532,332	31,794	1,056,439	71,733	246,138	257,794	18,295	48%
Total		6,729,898	3,653,503	59,503	2,029,386	117,221	377,313	405,248	38,782	
Regulatory Credits		2,803								AE-ALL
- Demand	DMD-ALL	1,451	884	12	405	19	55	61	9	52%
- Customer		-	-	-	-	-	-	-	-	0%
- Commodity	NRG-ALL	1,352	638	13	440	30	103	107	8	48%
Total		2,803	1,522	25	845	49	157	169	16	
Total Depreciation and Amortization		30,494,809								
- Demand		16,776,768	3,362,136	119,443	2,046,143	62,828	157,951	177,552	10,828,779	
- Customer		9,810,366	7,489,108	100,632	941,022	20,757	635,456	616,665	-	
- Commodity		3,907,674	1,845,115	38,283	1,272,081	86,375	296,380	310,416	22,029	
Total		**30,494,809**	**12,696,359**	**258,359**	**4,259,245**	**169,960**	**1,089,786**	**1,104,633**	**10,850,808**	
TAXES										
Taxes Other than Income										
(408) Payroll Taxes		1,046,433								PAY-CS
- Demand	PAY-CS-D	235,224	99,129	2,075	50,671	2,030	5,614	-	75,705	22%
- Customer	PAY-CS-C	683,026	584,029	8,210	75,127	309	6,861	6,980	1,440	65%
- Commodity	PAY-CS-E	128,182	66,325	1,376	45,727	3,105	10,654	182	792	12%
Total		1,046,433	749,483	11,661	171,525	5,444	23,129	7,162	77,937	
(408) Property Taxes		552,539								RB-CS
- Demand	RB-CS-D	314,950	70,213	2,356	41,805	1,329	3,390	3,703	191,698	57%
- Customer	RB-CS-C	153,821	113,700	1,507	14,187	390	12,086	11,749	73	28%
- Commodity	RB-CS-E	83,768	39,653	823	27,338	1,856	6,369	6,483	473	15%
Total		552,539	223,566	4,685	83,330	3,575	21,846	21,935	192,244	
Total Taxes Other than Income		1,598,972								
- Demand		550,174	169,341	4,430	92,476	3,359	9,005	3,703	267,403	
- Customer		836,847	697,729	9,718	89,314	699	18,947	18,730	1,512	
- Commodity		211,951	105,978	2,199	73,065	4,961	17,023	6,665	1,265	
Total Taxes Other than Income		**1,598,972**	**973,049**	**16,347**	**254,854**	**9,019**	**44,975**	**29,098**	**270,181**	
Total Expenses		**120,370,322**								
- Demand		**37,377,424**	**12,055,027**	**299,882**	**6,495,515**	**242,278**	**654,346**	**205,654**	**17,399,551**	
- Customer		**67,717,674**	**56,992,525**	**796,596**	**7,309,801**	**47,160**	**1,223,793**	**1,214,421**	**120,653**	
- Commodity		**15,275,224**	**7,714,926**	**159,971**	**5,300,186**	**359,358**	**1,232,806**	**371,438**	**92,343**	
Total		**120,370,322**	**76,762,478**	**1,256,449**	**19,105,502**	**648,796**	**3,110,946**	**1,791,513**	**17,612,546**	

Jersey Central Power & Light - First Energy Corp. Allocation to Customer Classes Customer Service	Allocation Factor	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	Lighting LTG	Classification Factor
REVENUE REQUIREMENT CALCULATION										
Total Rate Base										
- Demand		186,684,349	41,617,977	1,396,294	24,779,320	787,804	2,009,582	2,194,815	113,627,386	
- Customer		91,176,046	67,395,055	893,316	8,409,334	231,135	7,163,868	6,964,377	43,041	
- Commodity		49,653,101	23,504,026	487,672	16,204,424	1,100,290	3,775,438	3,842,664	280,618	
Total		327,513,495	132,517,058	2,777,282	49,393,078	2,119,229	12,948,888	13,001,856	113,951,045	
Required Net Income										
- Demand		14,188,010	3,162,966	106,118	1,883,228	59,873	152,728	166,806	8,635,681	
- Customer		6,929,379	5,122,024	67,892	639,109	17,566	544,454	529,293	3,271	
- Commodity		3,773,636	1,786,306	37,063	1,231,536	83,622	286,933	292,042	21,327	
Total		24,891,026	10,071,296	211,073	3,753,874	161,061	984,116	988,141	8,660,279	
Interest Synchronization										
- Demand		4,105,435	915,234	30,706	544,930	17,325	44,193	48,267	2,498,816	
- Customer		2,005,082	1,482,106	19,645	184,932	5,083	157,543	153,156	947	
- Commodity		1,091,937	516,885	10,725	356,357	24,197	83,027	84,505	6,171	
Total		7,202,454	2,914,225	61,076	1,086,219	46,605	284,763	285,928	2,505,934	
Net Income Before Income Taxes										
- Demand		10,082,575	2,247,732	75,412	1,338,298	42,548	108,535	118,539	6,136,865	
- Customer		4,924,298	3,639,918	48,247	454,177	12,483	386,911	376,137	2,325	
- Commodity		2,681,698	1,269,421	26,339	875,180	59,425	203,906	207,537	15,156	
Total		17,688,572	7,157,071	149,997	2,667,655	114,457	699,352	702,213	6,154,346	
Taxable Income										
- Demand		14,025,004	3,126,627	104,899	1,861,592	59,185	150,974	164,889	8,536,466	
- Customer		6,849,768	5,063,177	67,112	631,767	17,364	538,199	523,212	3,234	
- Commodity		3,730,280	1,765,783	36,637	1,217,387	82,661	283,637	288,687	21,082	
Total		24,605,052	9,955,587	208,648	3,710,746	159,211	972,809	976,788	8,560,781	
NJ State Corporate Business Tax										
- Demand		1,262,250	281,396	9,441	167,543	5,327	13,588	14,840	768,282	
- Customer		616,479	455,686	6,040	56,859	1,563	48,438	47,089	291	
- Commodity		335,725	158,920	3,297	109,565	7,440	25,527	25,982	1,897	
Total		2,214,455	896,003	18,778	333,967	14,329	87,553	87,911	770,470	
Federal Taxable Income										
- Demand		12,762,754	2,845,230	95,458	1,694,049	53,859	137,386	150,049	7,768,184	
- Customer		6,233,288	4,607,491	61,072	574,908	15,802	489,761	476,123	2,943	
- Commodity		3,394,555	1,606,863	33,340	1,107,822	75,222	258,109	262,705	19,185	
Total		22,390,597	9,059,584	189,870	3,376,778	144,882	885,256	888,877	7,790,311	
Federal Income Tax										
- Demand		2,680,178	597,498	20,046	355,750	11,310	28,851	31,510	1,631,319	
- Customer		1,308,991	967,573	12,825	120,731	3,318	102,850	99,986	618	
- Commodity		712,857	337,441	7,001	232,643	15,797	54,203	55,168	4,029	
Total		4,702,025	1,902,513	39,873	709,123	30,425	185,904	186,664	1,635,965	
NJ Federal & State Income Tax		6,916,480								
- Demand		3,942,429	878,895	29,487	523,293	16,637	42,439	46,350	2,399,600	
- Customer		1,925,470	1,423,259	18,865	177,590	4,881	151,288	147,075	909	
- Commodity		1,048,582	496,362	10,299	342,208	23,236	79,730	81,150	5,926	
Total		6,916,480	2,798,515	58,651	1,043,091	44,754	273,457	274,575	2,406,436	
Tax Reform Amortization		(1,014,645)								RB-CS
- Demand	RB-CS-D	(578,353)	(128,933)	(4,326)	(76,767)	(2,441)	(6,226)	(6,800)	(352,020)	57%
- Customer	RB-CS-C	(282,466)	(208,791)	(2,768)	(26,052)	(716)	(22,194)	(21,576)	(133)	28%
- Commodity	RB-CS-E	(153,826)	(72,816)	(1,511)	(50,202)	(3,409)	(11,696)	(11,905)	(869)	15%
Total		(1,014,645)	(410,541)	(8,604)	(153,021)	(6,565)	(40,116)	(40,280)	(353,023)	
Investment Tax Credit		(14,797)								RB-CS
- Demand	RB-CS-D	(8,435)	(1,880)	(63)	(1,120)	(36)	(91)	(99)	(5,134)	57%
- Customer	RB-CS-C	(4,119)	(3,045)	(40)	(380)	(10)	(324)	(315)	(2)	28%
- Commodity	RB-CS-E	(2,243)	(1,062)	(22)	(732)	(50)	(171)	(174)	(13)	15%
Total		(14,797)	(5,987)	(125)	(2,232)	(96)	(585)	(587)	(5,148)	
Federal & State Income Taxes										
- Demand		3,355,642	748,081	25,098	445,407	14,161	36,122	39,452	2,042,446	
- Customer		1,638,885	1,211,423	16,057	151,157	4,155	128,770	125,184	774	
- Commodity		892,512	422,484	8,766	291,274	19,778	67,863	69,072	5,044	
Total		5,887,038	2,381,987	49,922	887,838	38,093	232,756	233,708	2,048,264	
Revenue Requirement										
- Demand		**54,921,076**	**15,966,074**	**431,098**	**8,824,150**	**316,312**	**843,197**	**411,912**	**28,077,679**	
- Customer		**76,285,938**	**63,325,972**	**880,545**	**8,100,068**	**68,880**	**1,897,017**	**1,868,898**	**124,697**	
- Commodity		**19,941,372**	**9,923,715**	**205,800**	**6,822,996**	**462,758**	**1,587,603**	**732,552**	**118,714**	
Total		**151,148,386**	**89,215,762**	**1,517,444**	**23,747,214**	**847,950**	**4,327,817**	**3,013,362**	**28,321,090**	

Jersey Central Power & Light - First Energy Corp. Summary of Allocation Factors	Primary	Secondary	Customer Service
UTILITY PLANT			
Intangible Plant			
(301) Organizational Costs			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(302) Franchises & Consents			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(303) Misc. Intangible Plant			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
Distribution Plant			
(360) Land and Land Rights			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(361) Structures and Improvements			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(362) Station Equipment			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(364) Poles, Towers & Fixtures			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(365) Overhead Conductors & Devices			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(366) Underground Conduit			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	

Jersey Central Power & Light - First Energy Corp. Summary of Allocation Factors	Primary	Secondary	Customer Service
(367) Underground Conductors & Device			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(368) Line Transformers			
- Demand		DMD-SEC	
- Customer			
- Commodity		NRG-SEC	
(369) Services			
- Demand		DMD-SEC	
- Customer		CUST-SVCS	
- Commodity			
(370) Meters			
- Demand			DMD-MTR
- Customer			CUST-MTR
- Commodity			
(371) Installation on Customers' Premises			
- Demand			DMD-LTG
- Customer			
- Commodity			
(373) Street Lighting & Signal Systems			
- Demand			DMD-LTG
- Customer			
- Commodity			
(374) Asset Retirement Costs			
- Demand	DMD-PRI		
- Customer			
- Commodity	NRG-PRI		
(375) Charging Stations			
- Demand			
- Customer			
- Commodity			
General Plant			
(389) Land and Land Rights			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(390) Structures and Improvements			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL

Jersey Central Power & Light - First Energy Corp. Summary of Allocation Factors	Primary	Secondary	Customer Service
(391) Office Furniture & Equipment			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(392) Transportation Equipment			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(393) Stores Equipment			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(394) Tools, Shop & Garage Equipment			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(395) Laboratory Equipment			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(396) Power Operated Equipment			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(397) Communication Equipment			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(398) Misc. Equipment			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(399) Other Tangible Property			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(SRVCO-PIS) Service Company PIS			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL

Jersey Central Power & Light - First Energy Corp. Summary of Allocation Factors	Primary	Secondary	Customer Service
Additions to Utility Plant			
Construction Work in Progress			
- Demand			
- Customer			
- Commodity			
ACCUMULATED DEPRECIATION			
Accumulated Depreciation			
(108-303) Misc Intangible Plant			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(108-360) Land & Land Rights			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(108-361) Struct & Impmnts			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(108-362) Station Equip			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(108-364) Poles, Towers & Fixt			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(108-365) OH Cond & Dev			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(108-366) UG Conduit			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(108-367) UG Cond & Dev			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	

Jersey Central Power & Light - First Energy Corp. Summary of Allocation Factors	Primary	Secondary	Customer Service
(108-368) Line Transformers			
- Demand		DMD-SEC	
- Customer			
- Commodity		NRG-SEC	
(108-369) Services			
- Demand		DMD-SEC	
- Customer		CUST-SVCS	
- Commodity			
(108-370) Meters			
- Demand			DMD-MTR
- Customer			CUST-MTR
- Commodity			
(108-371) Install on Cust Premise			
- Demand			DMD-LTG
- Customer			
- Commodity			
(108-373) St Lt & Signal Sys			
- Demand			DMD-LTG
- Customer			
- Commodity			
(108-374) Asset Ret Costs			
- Demand	DMD-PRI		
- Customer			
- Commodity	NRG-PRI		
(108-389) Land & Land Rights			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(108-390) Struct & Impmnts -			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(108-391) Office Furn & Equip			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(108-392) Transportation Equip			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL

Jersey Central Power & Light - First Energy Corp. Summary of Allocation Factors	Primary	Secondary	Customer Service
(108-393) Stores Equip			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(108-394) Tools, Shop & Garage Equip			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(108-395) Laboratory Equip			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(108-396) Power Operated Equip			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(108-397) Communication Equip			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(108-398) MISC Equip			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(108-399) Other Tangible Property			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
Service Company PIS			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
OTHER RATE BASE ITEMS			
Other Rate Base Items			
Materials and Supplies			
- Demand	DISTPLT-PRI-D	DISTPLT-SEC-D	DISTPLT-CS-D
- Customer	DISTPLT-PRI-C	DISTPLT-SEC-C	DISTPLT-CS-C
- Commodity	DISTPLT-PRI-E	DISTPLT-SEC-E	DISTPLT-CS-E

Jersey Central Power & Light - First Energy Corp. Summary of Allocation Factors	Primary	Secondary	Customer Service
Cash Working Capital			
- Demand	CWC-PRI-D	CWC-SEC-D	CWC-CS-D
- Customer	CWC-PRI-C	CWC-SEC-C	CWC-CS-C
- Commodity	CWC-PRI-E	CWC-SEC-E	CWC-CS-E
ADIT			
- Demand	DISTPLT-PRI-D	DISTPLT-SEC-D	DISTPLT-CS-D
- Customer	DISTPLT-PRI-C	DISTPLT-SEC-C	DISTPLT-CS-C
- Commodity	DISTPLT-PRI-E	DISTPLT-SEC-E	DISTPLT-CS-E
Net /Loss on Reacq Debt			
- Demand	DISTPLT-PRI-D	DISTPLT-SEC-D	DISTPLT-CS-D
- Customer	DISTPLT-PRI-C	DISTPLT-SEC-C	DISTPLT-CS-C
- Commodity	DISTPLT-PRI-E	DISTPLT-SEC-E	DISTPLT-CS-E
DTA for AMT			
- Demand	DISTPLT-PRI-D	DISTPLT-SEC-D	DISTPLT-CS-D
- Customer	DISTPLT-PRI-C	DISTPLT-SEC-C	DISTPLT-CS-C
- Commodity	DISTPLT-PRI-E	DISTPLT-SEC-E	DISTPLT-CS-E
Net Operating Reserves			
- Demand	PAY-PRI-D	PAY-SEC-D	PAY-CS-D
- Customer	PAY-PRI-C	PAY-SEC-C	PAY-CS-C
- Commodity	PAY-PRI-E	PAY-SEC-E	PAY-CS-E
NOL			
- Demand	DISTPLT-PRI-D	DISTPLT-SEC-D	DISTPLT-CS-D
- Customer	DISTPLT-PRI-C	DISTPLT-SEC-C	DISTPLT-CS-C
- Commodity	DISTPLT-PRI-E	DISTPLT-SEC-E	DISTPLT-CS-E
CTA			
- Demand	TOTPLT-PRI-D	TOTPLT-SEC-D	TOTPLT-CS-D
- Customer	TOTPLT-PRI-C	TOTPLT-SEC-C	TOTPLT-CS-C
- Commodity	TOTPLT-PRI-E	TOTPLT-SEC-E	TOTPLT-CS-E
Regulatory Asset A&G Capitalization			
- Demand	DMD-PRI	DMD-PRI	DMD-PRI
- Customer	CUST-GTA&G	CUST-GTA&G	CUST-GTA&G
- Commodity	NRG-PRI	NRG-PRI	NRG-PRI
Customer Deposits			
- Demand			
- Customer			CUST-DEP
- Commodity			
Customer Advances			
- Demand	DISTPLT-PRI-D	DISTPLT-SEC-D	DISTPLT-CS-D
- Customer	DISTPLT-PRI-C	DISTPLT-SEC-C	DISTPLT-CS-C
- Commodity	DISTPLT-PRI-E	DISTPLT-SEC-E	DISTPLT-CS-E

Jersey Central Power & Light - First Energy Corp. Summary of Allocation Factors	Primary	Secondary	Customer Service
Customer Refunds			
- Demand	DISTPLT-PRI-D	DISTPLT-SEC-D	DISTPLT-CS-D
- Customer	DISTPLT-PRI-C	DISTPLT-SEC-C	DISTPLT-CS-C
- Commodity	DISTPLT-PRI-E	DISTPLT-SEC-E	DISTPLT-CS-E
OPERATIONS & MAINTENANCE EXPENSES			
Distribution Expenses			
Operations Expenses			
(580) Operation Supervision & Engineering			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(581) Load Dispatching			
- Demand	DMD-PRI		
- Customer			
- Commodity	NRG-PRI		
(582) Station Expenses			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(583) Overhead line expenses			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(584) Underground line expenses			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(585) Street lighting and signal system expenses			
- Demand			
- Customer			
- Commodity			
(586) Meter expenses			
- Demand			DMD-MTR
- Customer			CUST-MTR
- Commodity			
(587) Customer installations expenses			
- Demand			
- Customer			
- Commodity			

Jersey Central Power & Light - First Energy Corp. Summary of Allocation Factors	Primary	Secondary	Customer Service
(588) Miscellaneous distribution expenses			
- Demand	DISTPLT-PRI-D	DISTPLT-SEC-D	DISTPLT-CS-D
- Customer	DISTPLT-PRI-C	DISTPLT-SEC-C	DISTPLT-CS-C
- Commodity	DISTPLT-PRI-E	DISTPLT-SEC-E	DISTPLT-CS-E
(589) Rents			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
Total Dist. Operations Expenses			
- Demand			
- Customer			
- Commodity			
Maintenance Expense			
(590) Maintenance Supervision and Engineering			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(591) Maintenance of Structures			
- Demand	DMD-PRI		
- Customer			
- Commodity	NRG-PRI		
(592) Maintenance of Station Equipment			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(593) Maintenance of Overhead Lines			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(594) Maintenance of underground lines			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(595) Maintenance of line transformers			
- Demand		DMD-SEC	
- Customer			
- Commodity			
(596) Maintenance of street lighting and signal systems			
- Demand			DMD-LTG
- Customer			
- Commodity			

Jersey Central Power & Light - First Energy Corp. Summary of Allocation Factors	Primary	Secondary	Customer Service
(597) Maintenance of meters			
- Demand			DMD-MTR
- Customer			CUST-MTR
- Commodity			
(598) Maintenance of miscellaneous distribution plant			
- Demand	DISTPLT-PRI-D	DISTPLT-SEC-D	DISTPLT-CS-D
- Customer	DISTPLT-PRI-C	DISTPLT-SEC-C	DISTPLT-CS-C
- Commodity	DISTPLT-PRI-E	DISTPLT-SEC-E	DISTPLT-CS-E
Total Dist. Maintenance Expenses			
- Demand			
- Customer			
- Commodity			
Customer Account Expense			
(901) Supervision			
- Demand			
- Customer			CUST-ALL
- Commodity			
(902) Meter reading expenses			
- Demand			
- Customer			CUST-ALL
- Commodity			
(903) Customer records and collection expenses			
- Demand			
- Customer			CUST-ALL
- Commodity			
(904) Uncollectible accounts			
- Demand			
- Customer			
- Commodity			NRG-ALL
(905) Miscellaneous customer accounts expenses			
- Demand			
- Customer			CUST-ALL
- Commodity			
Customer Service Expenses			
(907) Customer Service Supervision			
- Demand			
- Customer			CUST-ALL
- Commodity			
(908) Customer Assistance			
- Demand			
- Customer			CUST-ALL
- Commodity			

Jersey Central Power & Light - First Energy Corp. Summary of Allocation Factors	Primary	Secondary	Customer Service
(909) Informational and instructional advertising			
- Demand			
- Customer			CUST-ALL
- Commodity			
(910) Miscellaneous customer service and informational			
- Demand			
- Customer			CUST-ALL
- Commodity			
Sales Expenses			
(911) Sales Exp			
- Demand			DMD-PRI
- Customer			
- Commodity			NRG-PRI
Administrative & General Expense			
Labor Related			
(920) Administrative and general salaries			
- Demand	DMD-PRI	DMD-PRI	DMD-PRI
- Customer	CUST-GTA&G	CUST-GTA&G	CUST-GTA&G
- Commodity	NRG-PRI	NRG-PRI	NRG-PRI
(921) Office supplies and expenses			
- Demand	DMD-PRI	DMD-PRI	DMD-PRI
- Customer	CUST-GTA&G	CUST-GTA&G	CUST-GTA&G
- Commodity	NRG-PRI	NRG-PRI	NRG-PRI
(922) Administrative expenses transferred—Credit			
- Demand	DMD-PRI	DMD-PRI	DMD-PRI
- Customer	CUST-GTA&G	CUST-GTA&G	CUST-GTA&G
- Commodity	NRG-PRI	NRG-PRI	NRG-PRI
(923) Outside services employed			
- Demand	DMD-PRI	DMD-PRI	DMD-PRI
- Customer	CUST-GTA&G	CUST-GTA&G	CUST-GTA&G
- Commodity	NRG-PRI	NRG-PRI	NRG-PRI
(926) Employee pensions and benefits			
- Demand	DMD-PRI	DMD-PRI	DMD-PRI
- Customer	CUST-GTA&G	CUST-GTA&G	CUST-GTA&G
- Commodity	NRG-PRI	NRG-PRI	NRG-PRI
(426) Pension / OPEB Non-Service Cost			
- Demand			
- Customer			
- Commodity			

Jersey Central Power & Light - First Energy Corp. Summary of Allocation Factors	Primary	Secondary	Customer Service
(924) Property insurance			
- Demand	DMD-PRI	DMD-PRI	DMD-PRI
- Customer	CUST-GTA&G	CUST-GTA&G	CUST-GTA&G
- Commodity	NRG-PRI	NRG-PRI	NRG-PRI
(925) Injuries and damages			
- Demand	DMD-PRI	DMD-PRI	DMD-PRI
- Customer	CUST-GTA&G	CUST-GTA&G	CUST-GTA&G
- Commodity	NRG-PRI	NRG-PRI	NRG-PRI
(935) Maintenance of general plant			
- Demand	DMD-PRI	DMD-PRI	DMD-PRI
- Customer	CUST-GTA&G	CUST-GTA&G	CUST-GTA&G
- Commodity	NRG-PRI	NRG-PRI	NRG-PRI
(929) Duplicate charges—Credit			
- Demand			
- Customer			
- Commodity			
(928) Regulatory commission expenses			
- Demand	DMD-PRI	DMD-PRI	DMD-PRI
- Customer	CUST-GTA&G	CUST-GTA&G	CUST-GTA&G
- Commodity	NRG-PRI	NRG-PRI	NRG-PRI
(930.1) Gen Advertising Exp			
- Demand	DMD-PRI	DMD-PRI	DMD-PRI
- Customer	CUST-GTA&G	CUST-GTA&G	CUST-GTA&G
- Commodity	NRG-PRI	NRG-PRI	NRG-PRI
(930.2) Misc Gen Exp			
- Demand	DMD-PRI	DMD-PRI	DMD-PRI
- Customer	CUST-GTA&G	CUST-GTA&G	CUST-GTA&G
- Commodity	NRG-PRI	NRG-PRI	NRG-PRI
(931) Rents			
- Demand	DMD-PRI	DMD-PRI	DMD-PRI
- Customer	CUST-GTA&G	CUST-GTA&G	CUST-GTA&G
- Commodity	NRG-PRI	NRG-PRI	NRG-PRI
(932) Institutional Ad - Newspaper			
- Demand			
- Customer			
- Commodity			
(933) Transportation expenses			
- Demand			
- Customer			
- Commodity			

Jersey Central Power & Light - First Energy Corp. Summary of Allocation Factors	Primary	Secondary	Customer Service
DEPRECIATION EXPENSE			
Depreciation Expense			
(403-360) Land & Land Rights			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(403-361) Struct & Impmnts			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(403-362) Station Equip			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(403-364) Poles, Towers & Fixt			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(403-365) OH Cond & Dev			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(403-366) UG Conduit			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(403-367) UG Cond & Dev			
- Demand	DMD-PRI	DMD-SEC	
- Customer			
- Commodity	NRG-PRI	NRG-SEC	
(403-368) Line Transformers			
- Demand		DMD-SEC	
- Customer			
- Commodity		NRG-SEC	
(403-369) Services			
- Demand		DMD-SEC	
- Customer		CUST-SVCS	
- Commodity			

Jersey Central Power & Light - First Energy Corp. Summary of Allocation Factors	Primary	Secondary	Customer Service
(403-370) Meters			
- Demand			DMD-MTR
- Customer			CUST-MTR
- Commodity			
(403-371) Install on Cust Premise			
- Demand			DMD-LTG
- Customer			
- Commodity			
(403-373) St Lt & Signal Sys			
- Demand			DMD-LTG
- Customer			
- Commodity			
(403-374) Asset Ret Costs			
- Demand	DMD-PRI		
- Customer			
- Commodity	NRG-PRI		
(403-389) Land & Land Rights			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(403-390) Struct & Impmnts -			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(403-391) Office Furn & Equip			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(403-392) Transportation Equip			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(403-393) Stores Equip			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(403-394) Tools, Shop & Garage Equip			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL

Jersey Central Power & Light - First Energy Corp. Summary of Allocation Factors	Primary	Secondary	Customer Service
(403-395) Laboratory Equip			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(403-396) Power Operated Equip			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(403-397) Communication Equip			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
(403-398) MISC Equip			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
Amort - Ltd Term Elec Prpty			
- Demand	DISTPLT-PRI-D	DISTPLT-SEC-D	DISTPLT-CS-D
- Customer	DISTPLT-PRI-C	DISTPLT-SEC-C	DISTPLT-CS-C
- Commodity	DISTPLT-PRI-E	DISTPLT-SEC-E	DISTPLT-CS-E
Accretion Expense			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
Regulatory Debits			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
Regulatory Credits			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL

Jersey Central Power & Light - First Energy Corp. Summary of Allocation Factors	Primary	Secondary	Customer Service
TAXES			
Taxes Other than Income			
(408) Payroll Taxes			
- Demand	PAY-PRI-D	PAY-SEC-D	PAY-CS-D
- Customer	PAY-PRI-C	PAY-SEC-C	PAY-CS-C
- Commodity	PAY-PRI-E	PAY-SEC-E	PAY-CS-E
(408) Property Taxes			
- Demand	RB-PRI-D	RB-SEC-D	RB-CS-D
- Customer	RB-PRI-C	RB-SEC-C	RB-CS-C
- Commodity	RB-PRI-E	RB-SEC-E	RB-CS-E
Interest Synchronization			
- Demand			
- Customer			
- Commodity			
ADJUSTMENTS			
O&M Adjustments			
Int on Cust Deposits			
- Demand			
- Customer	CUST-DEP	CUST-DEP	CUST-DEP
- Commodity			
Annualize Payroll Increase			
- Demand	PAY-PRI-D	PAY-SEC-D	PAY-CS-D
- Customer	PAY-PRI-C	PAY-SEC-C	PAY-CS-C
- Commodity	PAY-PRI-E	PAY-SEC-E	PAY-CS-E
Svngs Pln Match on Payroll Inc			
- Demand	PAY-PRI-D	PAY-SEC-D	PAY-CS-D
- Customer	PAY-PRI-C	PAY-SEC-C	PAY-CS-C
- Commodity	PAY-PRI-E	PAY-SEC-E	PAY-CS-E
Reclass Amortization of Net Loss on Reacquired Debt			
- Demand	DISTPLT-PRI-D	DISTPLT-SEC-D	DISTPLT-CS-D
- Customer	DISTPLT-PRI-C	DISTPLT-SEC-C	DISTPLT-CS-C
- Commodity	DISTPLT-PRI-E	DISTPLT-SEC-E	DISTPLT-CS-E
BPU & RPA Assessments			
- Demand	DIST-REV-DMD	DIST-REV-DMD	DIST-REV-DMD
- Customer	DIST-REV-CUST	DIST-REV-CUST	DIST-REV-CUST
- Commodity	DIST-REV-NRG	DIST-REV-NRG	DIST-REV-NRG
Rate Case Exp			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL

Jersey Central Power & Light - First Energy Corp. Summary of Allocation Factors	Primary	Secondary	Customer Service
Pension Smoothing			
- Demand	PAY-PRI-D	PAY-SEC-D	PAY-CS-D
- Customer	PAY-PRI-C	PAY-SEC-C	PAY-CS-C
- Commodity	PAY-PRI-E	PAY-SEC-E	PAY-CS-E
OPEB Smoothing			
- Demand	PAY-PRI-D	PAY-SEC-D	PAY-CS-D
- Customer	PAY-PRI-C	PAY-SEC-C	PAY-CS-C
- Commodity	PAY-PRI-E	PAY-SEC-E	PAY-CS-E
Normalize Vegetation Management Expense			
- Demand	OHPLT-PRI-D	OHPLT-SEC-D	OHPLT-CS-D
- Customer	OHPLT-PRI-C	OHPLT-SEC-C	OHPLT-CS-C
- Commodity	OHPLT-PRI-E	OHPLT-SEC-E	OHPLT-CS-E
ServCo Depr @ JCP&L Rates			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
SERP/EDCP			
- Demand	PAY-PRI-D	PAY-SEC-D	PAY-CS-D
- Customer	PAY-PRI-C	PAY-SEC-C	PAY-CS-C
- Commodity	PAY-PRI-E	PAY-SEC-E	PAY-CS-E
BGS Administrative Labor included in BGS Deferral			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
Low Income O&M			
- Demand	DMD-ALL	DMD-ALL	DMD-ALL
- Customer			
- Commodity	NRG-ALL	NRG-ALL	NRG-ALL
Advertising removal			
- Demand	DMD-PRI		
- Customer	CUST-GTA&G		
- Commodity	NRG-PRI		
Contract Labor/Fuel Costs			
- Demand	DMD-PRI		
- Customer	CUST-GTA&G		
- Commodity	NRG-PRI		
Rate Base			
AMI			
- Demand			DMD-MTR
- Customer			CUST-MTR
- Commodity			

Jersey Central Power & Light - First Energy Corp. Summary of Allocation Factors	Primary	Secondary	Customer Service
Delayed Recognition Pension & OPEB			
- Demand	PAY-PRI-D	PAY-SEC-D	PAY-CS-D
- Customer	PAY-PRI-C	PAY-SEC-C	PAY-CS-C
- Commodity	PAY-PRI-E	PAY-SEC-E	PAY-CS-E
Depreciation			
Annualize Deprec Exp			
- Demand	DPR-TOT-PRI-D	DPR-TOT-SEC-D	DPR-TOT-CS-D
- Customer	DPR-TOT-PRI-C	DPR-TOT-SEC-C	DPR-TOT-CS-C
- Commodity	DPR-TOT-PRI-E	DPR-TOT-SEC-E	DPR-TOT-CS-E
Average Net Salvage			
- Demand	DISTPLT-PRI-D	DISTPLT-SEC-D	DISTPLT-CS-D
- Customer	DISTPLT-PRI-C	DISTPLT-SEC-C	DISTPLT-CS-C
- Commodity	DISTPLT-PRI-E	DISTPLT-SEC-E	DISTPLT-CS-E
Income			
Amortization of Fed Income Tax Credit			
- Demand	RB-PRI-D	RB-SEC-D	RB-CS-D
- Customer	RB-PRI-C	RB-SEC-C	RB-CS-C
- Commodity	RB-PRI-E	RB-SEC-E	RB-CS-E
Tax Reform Amortization			
- Demand	RB-PRI-D	RB-SEC-D	RB-CS-D
- Customer	RB-PRI-C	RB-SEC-C	RB-CS-C
- Commodity	RB-PRI-E	RB-SEC-E	RB-CS-E
Investment Tax Credit			
- Demand	RB-PRI-D	RB-SEC-D	RB-CS-D
- Customer	RB-PRI-C	RB-SEC-C	RB-CS-C
- Commodity	RB-PRI-E	RB-SEC-E	RB-CS-E

Jersey Central Power & Light - First Energy Corp. Summary of Classification Factors	Primary	Secondary	Customer Service
UTILITY PLANT			
Intangible Plant			
(301) Organizational Costs	AE-ALL	AE-ALL	AE-ALL
(302) Franchises & Consents	AE-ALL	AE-ALL	AE-ALL
(303) Misc. Intangible Plant	AE-ALL	AE-ALL	AE-ALL
Distribution Plant			
(360) Land and Land Rights	AE-PRI	AE-SEC	
(361) Structures and Improvements	AE-PRI	AE-SEC	
(362) Station Equipment	AE-PRI	AE-SEC	
(364) Poles, Towers & Fixtures	AE-PRI	AE-SEC	
(365) Overhead Conductors & Devices	AE-PRI	AE-SEC	
(366) Underground Conduit	AE-PRI	AE-SEC	
(367) Underground Conductors & Device	AE-PRI	AE-SEC	
(368) Line Transformers		AE-SEC	
(369) Services		SRVC	
(370) Meters			MTR
(371) Installation on Customers' Premises			DEM
(373) Street Lighting & Signal Systems			DEM
(374) Asset Retirement Costs	AE-PRI		
(375) Charging Stations			
General Plant			
(389) Land and Land Rights	AE-ALL	AE-ALL	AE-ALL
(390) Structures and Improvements	AE-ALL	AE-ALL	AE-ALL
(391) Office Furniture & Equipment	AE-ALL	AE-ALL	AE-ALL
(392) Transportation Equipment	AE-ALL	AE-ALL	AE-ALL
(393) Stores Equipment	AE-ALL	AE-ALL	AE-ALL
(394) Tools, Shop & Garage Equipment	AE-ALL	AE-ALL	AE-ALL
(395) Laboratory Equipment	AE-ALL	AE-ALL	AE-ALL
(396) Power Operated Equipment	AE-ALL	AE-ALL	AE-ALL
(397) Communication Equipment	AE-ALL	AE-ALL	AE-ALL
(398) Misc. Equipment	AE-ALL	AE-ALL	AE-ALL
(399) Other Tangible Property	AE-ALL	AE-ALL	AE-ALL
(SRVCO-PIS) Service Company PIS	AE-ALL	AE-ALL	AE-ALL
Additions to Utility Plant			
Construction Work in Progress			
ACCUMULATED DEPRECIATION			
Accumulated Depreciation			
(108-303) Misc Intangible Plant	AE-ALL	AE-ALL	AE-ALL
(108-360) Land & Land Rights	AE-PRI	AE-SEC	
(108-361) Struct & Impmnts	AE-PRI	AE-SEC	
(108-362) Station Equip	AE-PRI	AE-SEC	
(108-364) Poles, Towers & Fixt	AE-PRI	AE-SEC	
(108-365) OH Cond & Dev	AE-PRI	AE-SEC	
(108-366) UG Conduit	AE-PRI	AE-SEC	
(108-367) UG Cond & Dev	AE-PRI	AE-SEC	
(108-368) Line Transformers		AE-SEC	
(108-369) Services		SRVC	
(108-370) Meters			MTR
(108-371) Install on Cust Premise			DEM
(108-373) St Lt & Signal Sys			DEM
(108-374) Asset Ret Costs	AE-PRI		
(108-389) Land & Land Rights	AE-ALL	AE-ALL	AE-ALL
(108-390) Struct & Impmnts -	AE-ALL	AE-ALL	AE-ALL

Jersey Central Power & Light - First Energy Corp. Summary of Classification Factors	Primary	Secondary	Customer Service
(108-391) Office Furn & Equip	AE-ALL	AE-ALL	AE-ALL
(108-392) Transportation Equip	AE-ALL	AE-ALL	AE-ALL
(108-393) Stores Equip	AE-ALL	AE-ALL	AE-ALL
(108-394) Tools, Shop & Garage Equip	AE-ALL	AE-ALL	AE-ALL
(108-395) Laboratory Equip	AE-ALL	AE-ALL	AE-ALL
(108-396) Power Operated Equip	AE-ALL	AE-ALL	AE-ALL
(108-397) Communication Equip	AE-ALL	AE-ALL	AE-ALL
(108-398) MISC Equip	AE-ALL	AE-ALL	AE-ALL
(108-399) Other Tangible Property	AE-ALL	AE-ALL	AE-ALL
Service Company PIS	AE-ALL	AE-ALL	AE-ALL
OTHER RATE BASE ITEMS			
Other Rate Base Items			
Materials and Supplies	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
Cash Working Capital	CWC-PRI	CWC-SEC	CWC-CS
ADIT	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
Net /Loss on Reacq Debt	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
DTA for AMT	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
Net Operating Reserves	PAY-PRI	PAY-SEC	PAY-CS
NOL	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
CTA	TOTPLT-PRI	TOTPLT-SEC	TOTPLT-CS
Regulatory Asset A&G Capitalization	AE-PRI-GTA&G	AE-PRI-GTA&G	AE-PRI-GTA&G
Customer Deposits	CUS	CUS	CUS
Customer Advances	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
Customer Refunds	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
OPERATIONS & MAINTENANCE EXPENSES			
Distribution Expenses			
Operations Expenses			
(580) Operation Supervision & Engineering	AE-PRI	AE-SEC	
(581) Load Dispatching	AE-PRI		
(582) Station Expenses	AE-PRI	AE-SEC	
(583) Overhead line expenses	AE-PRI	AE-SEC	
(584) Underground line expenses	AE-PRI	AE-SEC	
(585) Street lighting and signal system expenses			
(586) Meter expenses			MTR
(587) Customer installations expenses			
(588) Miscellaneous distribution expenses	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
(589) Rents	AE-PRI	AE-SEC	
Maintenance Expense			
(590) Maintenance Supervision and Engineering	AE-PRI	AE-SEC	
(591) Maintenance of Structures	AE-PRI	AE-SEC	
(592) Maintenance of Station Equipment	AE-PRI	AE-SEC	
(593) Maintenance of Overhead Lines	AE-PRI	AE-SEC	
(594) Maintenance of underground lines	AE-PRI	AE-SEC	
(595) Maintenance of line transformers		DEM	
(596) Maintenance of street lighting and signal systems			DEM
(597) Maintenance of meters			MTR
(598) Maintenance of miscellaneous distribution p	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
Customer Account Expense			
(901) Supervision			CUS
(902) Meter reading expenses			CUS
(903) Customer records and collection expenses			CUS
(904) Uncollectible accounts			COM
(905) Miscellaneous customer accounts expenses			CUS

Jersey Central Power & Light - First Energy Corp. Summary of Classification Factors	Primary	Secondary	Customer Service
Customer Service Expenses			
(907) Customer Service Supervision			CUS
(908) Customer Assistance			CUS
(909) Informational and instructional advertising			CUS
(910) Miscellaneous customer service and informational			CUS
Sales Expenses			
(911) Sales Exp			AE-PRI
Administrative & General Expense			
(920) Administrative and general salaries	AE-PRI-GTA&G	AE-PRI-GTA&G	AE-PRI-GTA&G
(921) Office supplies and expenses	AE-PRI-GTA&G	AE-PRI-GTA&G	AE-PRI-GTA&G
(922) Administrative expenses transferred—Credit	AE-PRI-GTA&G	AE-PRI-GTA&G	AE-PRI-GTA&G
(923) Outside services employed	AE-PRI-GTA&G	AE-PRI-GTA&G	AE-PRI-GTA&G
(926) Employee pensions and benefits	AE-PRI-GTA&G	AE-PRI-GTA&G	AE-PRI-GTA&G
(426) Pension / OPEB Non-Service Cost	AE-PRI-GTA&G	AE-PRI-GTA&G	AE-PRI-GTA&G
(924) Property insurance	AE-PRI-GTA&G	AE-PRI-GTA&G	AE-PRI-GTA&G
(925) Injuries and damages	AE-PRI-GTA&G	AE-PRI-GTA&G	AE-PRI-GTA&G
(935) Maintenance of general plant	AE-PRI-GTA&G	AE-PRI-GTA&G	AE-PRI-GTA&G
(929) Duplicate charges—Credit	AE-PRI-GTA&G	AE-PRI-GTA&G	AE-PRI-GTA&G
(928) Regulatory commission expenses	AE-PRI-GTA&G	AE-PRI-GTA&G	AE-PRI-GTA&G
(930.1) Gen Advertising Exp	AE-PRI-GTA&G	AE-PRI-GTA&G	AE-PRI-GTA&G
(930.2) Misc Gen Exp	AE-PRI-GTA&G	AE-PRI-GTA&G	AE-PRI-GTA&G
(931) Rents	AE-PRI-GTA&G	AE-PRI-GTA&G	AE-PRI-GTA&G
(932) Institutional Ad - Newspaper			
(933) Transportation expenses			
DEPRECIATION EXPENSE			
Depreciation Expense			
(403-360) Land & Land Rights	AE-PRI	AE-SEC	
(403-361) Struct & Impmnts	AE-PRI	AE-SEC	
(403-362) Station Equip	AE-PRI	AE-SEC	
(403-364) Poles, Towers & Fixt	AE-PRI	AE-SEC	
(403-365) OH Cond & Dev	AE-PRI	AE-SEC	
(403-366) UG Conduit	AE-PRI	AE-SEC	
(403-367) UG Cond & Dev	AE-PRI	AE-SEC	
(403-368) Line Transformers		AE-SEC	
(403-369) Services		SRVC	
(403-370) Meters			MTR
(403-371) Install on Cust Premise			DEM
(403-373) St Lt & Signal Sys			DEM
(403-374) Asset Ret Costs	AE-PRI		
(403-389) Land & Land Rights	AE-ALL	AE-ALL	AE-ALL
(403-390) Struct & Impmnts -	AE-ALL	AE-ALL	AE-ALL
(403-391) Office Furn & Equip	AE-ALL	AE-ALL	AE-ALL
(403-392) Transportation Equip	AE-ALL	AE-ALL	AE-ALL
(403-393) Stores Equip	AE-ALL	AE-ALL	AE-ALL
(403-394) Tools, Shop & Garage Equip	AE-ALL	AE-ALL	AE-ALL
(403-395) Laboratory Equip	AE-ALL	AE-ALL	AE-ALL
(403-396) Power Operated Equip	AE-ALL	AE-ALL	AE-ALL
(403-397) Communication Equip	AE-ALL	AE-ALL	AE-ALL
(403-398) MISC Equip	AE-ALL	AE-ALL	AE-ALL
Amortization, Accretion, Regulatory Debits and Credits			
Amort - Ltd Term Elec Prpty	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
Accretion Expense	AE-ALL	AE-ALL	AE-ALL
Regulatory Debits	AE-ALL	AE-ALL	AE-ALL
Regulatory Credits	AE-ALL	AE-ALL	AE-ALL

Jersey Central Power & Light - First Energy Corp. Summary of Classification Factors	Primary	Secondary	Customer Service
TAXES			
Taxes Other than Income			
(408) Payroll Taxes	PAY-PRI	PAY-SEC	PAY-CS
(408) Property Taxes	RB-PRI	RB-SEC	RB-CS
Income Taxes			
Federal & State Income Taxes			
Income Tax Derivation			
Tax Reform Amortization	RB-PRI	RB-SEC	RB-CS
Investment Tax Credit	RB-PRI	RB-SEC	RB-CS
ADJUSTMENTS			
O&M			
Int on Cust Deposits	CUS	CUS	CUS
Annualize Payroll Increase	PAY-PRI	PAY-SEC	PAY-CS
Svngs Pln Match on Payroll Inc	PAY-PRI	PAY-SEC	PAY-CS
Reclass Amortization of Net Loss on Reacquired D	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS
BPU & RPA Assessments	DIST-REV	DIST-REV	DIST-REV
Rate Case Exp	AE-ALL	AE-ALL	AE-ALL
Pension Smoothing	PAY-PRI	PAY-SEC	PAY-CS
OPEB Smoothing	PAY-PRI	PAY-SEC	PAY-CS
Normalize Vegetation Management Expense	OHPLT-PRI	OHPLT-SEC	OHPLT-CS
ServCo Depr @ JCP&L Rates	AE-ALL	AE-ALL	AE-ALL
SERP/EDCP	PAY-PRI	PAY-SEC	PAY-CS
BGS Administrative Labor included in BGS Deferral	AE-ALL	AE-ALL	AE-ALL
Low Income O&M	AE-ALL	AE-ALL	AE-ALL
Advertising removal	AE-PRI-GTA&G		
Contract Labor/Fuel Costs	AE-PRI-GTA&G		
-	AE-PRI-GTA&G		
Rate Base			
AMI			MTR
Delayed Recognition Pension & OPEB	PAY-PRI	PAY-SEC	PAY-CS
Depreciation			
Annualize Deprec Exp	DPR-TOT-PRI	DPR-TOT-SEC	DPR-TOT-CS
Average Net Salvage	DISTPLT-PRI	DISTPLT-SEC	DISTPLT-CS

Jersey Central Power & Light - First Energy Corp. Summary of Allocators	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
External Allocators									
External Allocators									
ALL451	100.00%	79.94%	0.56%	18.39%	0.01%	0.06%	1.04%		0.00%
LATEPAY	100.00%	0.05%	0.00%	80.41%	3.43%	9.69%	2.69%		3.72%
ALL901	100.00%	79.26%	1.41%	18.52%	0.23%	0.21%	0.12%		0.25%
ALL905	100.00%	79.26%	1.41%	18.52%	0.23%	0.21%	0.12%		0.25%
CUST-ALL	100.00%	87.18%	1.23%	11.25%	0.02%	0.05%	0.01%		0.25%
CUST-PRI	100.00%	87.19%	1.23%	11.26%	0.02%	0.05%	0.00%		0.25%
CUST-SEC	100.00%	87.24%	1.23%	11.26%	0.02%	0.00%	0.00%		0.25%
CUST-DEP	100.00%	87.40%	1.24%	11.28%	0.02%	0.05%	0.01%		0.00%
CUST-GTA&G	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%		0.00%
CUST-LTG	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		100.00%
CUST-MTR	100.00%	76.34%	1.03%	9.59%	0.21%	6.48%	6.29%		0.00%
CUST-SVCS	100.00%	87.46%	1.24%	11.29%	0.02%	0.00%	0.00%		0.00%
DMD-MTR	100.00%	45.48%	4.84%	49.23%	0.45%	0.00%	0.00%		0.00%
DMD-ALL	100.00%	60.87%	0.80%	27.92%	1.31%	3.76%	4.23%		0.59%
DMD-PRI	100.00%	63.91%	0.83%	29.31%	1.37%	3.95%	0.00%		0.62%
DMD-SEC	100.00%	66.54%	0.87%	30.52%	1.43%	0.00%	0.00%		0.64%
DMD-LTG	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		100.00%
DIST-REV-DMD	100.00%	0.00%	0.00%	64.62%	5.10%	12.57%	9.34%		8.19%
DIST-REV-CUST	100.00%	71.32%	2.18%	24.49%	0.21%	0.80%	0.99%		0.00%
DIST-REV-NRG	100.00%	74.27%	1.37%	20.29%	0.51%	1.30%	0.99%		1.27%
NRG-ALL	100.00%	47.22%	0.98%	32.55%	2.21%	7.58%	7.94%		0.56%
NRG-PRI	100.00%	51.83%	1.08%	35.73%	2.43%	8.32%	0.00%		0.62%
NRG-SEC	100.00%	56.53%	1.17%	38.97%	2.65%	0.00%	0.00%		0.67%
REV-ALL	100.00%	54.42%	1.08%	32.33%	1.69%	4.24%	3.19%		3.00%

Jersey Central Power & Light - First Energy Corp. Summary of Allocators	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
Internal Allocators									
DISTPLT-PRI-D	100.00%	63.91%	0.83%	29.31%	1.37%	3.95%	0.00%		0.62%
DISTPLT-PRI-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		0.00%
DISTPLT-PRI-E	100.00%	51.83%	1.08%	35.73%	2.43%	8.32%	0.00%		0.62%
DISTPLT-SEC-D	100.00%	66.54%	0.87%	30.52%	1.43%	0.00%	0.00%		0.64%
DISTPLT-SEC-C	100.00%	87.46%	1.24%	11.29%	0.02%	0.00%	0.00%		0.00%
DISTPLT-SEC-E	100.00%	56.53%	1.17%	38.97%	2.65%	0.00%	0.00%		0.67%
DISTPLT-CS-D	100.00%	4.33%	0.46%	4.69%	0.04%	0.00%	0.00%		90.48%
DISTPLT-CS-C	100.00%	76.34%	1.03%	9.59%	0.21%	6.48%	6.29%		0.00%
DISTPLT-CS-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		0.00%
RB-PRI-D	100.00%	63.63%	0.83%	29.19%	1.36%	3.94%	0.39%		0.61%
RB-PRI-C	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%		0.00%
RB-PRI-E	100.00%	51.39%	1.07%	35.43%	2.41%	8.25%	0.76%		0.61%
RB-SEC-D	100.00%	66.21%	0.86%	30.37%	1.42%	0.26%	0.21%		0.64%
RB-SEC-C	100.00%	87.43%	1.24%	11.29%	0.02%	0.00%	0.03%		0.00%
RB-SEC-E	100.00%	55.92%	1.16%	38.56%	2.62%	0.58%	0.44%		0.67%
RB-CS-D	100.00%	22.29%	0.75%	13.27%	0.42%	1.08%	1.18%		60.87%
RB-CS-C	100.00%	73.92%	0.98%	9.22%	0.25%	7.86%	7.64%		0.05%
RB-CS-E	100.00%	47.34%	0.98%	32.64%	2.22%	7.60%	7.74%		0.57%
PAY-PRI-D	100.00%	63.91%	0.83%	29.31%	1.37%	3.95%	0.00%		0.62%
PAY-PRI-C	100.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%		0.00%
PAY-PRI-E	100.00%	51.83%	1.08%	35.73%	2.43%	8.32%	0.00%		0.62%
PAY-SEC-D	100.00%	65.78%	0.86%	30.17%	1.41%	1.15%	0.00%		0.64%
PAY-SEC-C	100.00%	84.79%	1.20%	10.95%	0.02%	0.00%	3.05%		0.00%
PAY-SEC-E	100.00%	55.10%	1.14%	37.99%	2.58%	2.52%	0.00%		0.66%
PAY-CS-D	100.00%	42.14%	0.88%	21.54%	0.86%	2.39%	0.00%		32.18%
PAY-CS-C	100.00%	85.51%	1.20%	11.00%	0.05%	1.00%	1.02%		0.21%
PAY-CS-E	100.00%	51.74%	1.07%	35.67%	2.42%	8.31%	0.14%		0.62%
TOTPLT-PRI-D	100.00%	63.62%	0.83%	29.18%	1.36%	3.93%	0.41%		0.61%
TOTPLT-PRI-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		0.00%
TOTPLT-PRI-E	100.00%	51.36%	1.07%	35.41%	2.40%	8.25%	0.80%		0.61%
TOTPLT-SEC-D	100.00%	66.08%	0.86%	30.31%	1.42%	0.31%	0.34%		0.64%
TOTPLT-SEC-C	100.00%	87.46%	1.24%	11.29%	0.02%	0.00%	0.00%		0.00%
TOTPLT-SEC-E	100.00%	55.70%	1.16%	38.40%	2.61%	0.68%	0.71%		0.66%

Jersey Central Power & Light - First Energy Corp. Summary of Allocators	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
TOTPLT-CS-D	100.00%	14.09%	0.52%	8.70%	0.26%	0.65%	0.73%		74.96%
TOTPLT-CS-C	100.00%	76.34%	1.03%	9.59%	0.21%	6.48%	6.29%		0.00%
TOTPLT-CS-E	100.00%	47.22%	0.98%	32.55%	2.21%	7.58%	7.94%		0.56%
DPR-TOT-PRI-D	100.00%	63.62%	0.83%	29.18%	1.36%	3.93%	0.41%		0.61%
DPR-TOT-PRI-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		0.00%
DPR-TOT-PRI-E	100.00%	51.36%	1.07%	35.41%	2.40%	8.25%	0.81%		0.61%
DPR-TOT-SEC-D	100.00%	65.91%	0.86%	30.23%	1.41%	0.42%	0.47%		0.64%
DPR-TOT-SEC-C	100.00%	87.46%	1.24%	11.29%	0.02%	0.00%	0.00%		0.00%
DPR-TOT-SEC-E	100.00%	55.39%	1.15%	38.18%	2.59%	0.93%	0.98%		0.66%
DPR-TOT-CS-D	100.00%	9.69%	0.71%	8.34%	0.14%	0.21%	0.24%		80.64%
DPR-TOT-CS-C	100.00%	76.34%	1.03%	9.59%	0.21%	6.48%	6.29%		0.00%
DPR-TOT-CS-E	100.00%	47.22%	0.98%	32.55%	2.21%	7.58%	7.94%		0.56%
OHPLT-PRI-D	100.00%	63.91%	0.83%	29.31%	1.37%	3.95%	0.00%		0.62%
OHPLT-PRI-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		0.00%
OHPLT-PRI-E	100.00%	51.83%	1.08%	35.73%	2.43%	8.32%	0.00%		0.62%
OHPLT-SEC-D	100.00%	66.54%	0.87%	30.52%	1.43%	0.00%	0.00%		0.64%
OHPLT-SEC-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		0.00%
OHPLT-SEC-E	100.00%	56.53%	1.17%	38.97%	2.65%	0.00%	0.00%		0.67%
OHPLT-CS-D	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		0.00%
OHPLT-CS-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		0.00%
OHPLT-CS-E	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		0.00%
CWC-PRI-D	100.00%	63.91%	0.83%	29.31%	1.37%	3.95%	0.00%		0.62%
CWC-PRI-C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		0.00%
CWC-PRI-E	100.00%	51.83%	1.08%	35.73%	2.43%	8.32%	0.00%		0.62%
CWC-SEC-D	100.00%	66.54%	0.87%	30.52%	1.43%	0.00%	0.00%		0.64%
CWC-SEC-C	100.00%	87.46%	1.24%	11.29%	0.02%	0.00%	0.00%		0.00%
CWC-SEC-E	100.00%	56.53%	1.17%	38.97%	2.65%	0.00%	0.00%		0.67%
CWC-CS-D	100.00%	8.95%	0.95%	9.69%	0.09%	0.00%	0.00%		80.32%
CWC-CS-C	100.00%	85.57%	1.20%	11.01%	0.05%	1.01%	0.95%		0.21%
CWC-CS-E	100.00%	47.22%	0.98%	32.55%	2.21%	7.58%	7.94%		0.56%

Jersey Central Power & Light - First Energy Corp. Summary of Classifiers Classifier Description	Classifier Code	Total	- Demand	- Customer	- Commodity
External Classifiers					
Customer Factor	CUS	100.00%	0.00%	100.00%	0.00%
Demand Factor	DEM	100.00%	100.00%	0.00%	0.00%
Commodity Factor	COM	100.00%	0.00%	0.00%	100.00%
Avg/Excess All	AE-ALL	100.00%	51.78%	0.00%	48.22%
Avg/Excess Primary	AE-PRI	100.00%	53.02%	0.00%	46.98%
Avg/Exc Secondary	AE-SEC	100.00%	54.44%	0.00%	45.56%
Avg/Exc for GT A&G	AE-PRI-GTA&G	100.00%	52.91%	0.20%	46.89%
Distribution Revs	DIST-REV	100.00%	26.41%	8.05%	65.54%
Meters (Alternative Proposal)	MTR	100.00%	15.33%	84.67%	0.00%
Services (Alternative Proposal)	SRVC	100.00%	0.15%	99.85%	0.00%
Meters (Complied)		100.00%	44.50%	55.50%	0.00%
Services (Complied)		100.00%	50.00%	50.00%	0.00%
Meters (Alternative Proposal)		100.00%	15.33%	84.67%	0.00%
Services (Alternative Proposal)		100.00%	0.15%	99.85%	0.00%
Internal Classifiers					
Distribution Plant Primary	DISTPLT-PRI	100.00%	53.02%	0.00%	46.98%
Distribution Plant Secondary	DISTPLT-SEC	100.00%	46.08%	15.38%	38.54%
Distribution Plant Customer	DISTPLT-CS	100.00%	65.55%	34.45%	0.00%
Rate Base Primary	RB-PRI	100.00%	52.90%	0.00%	47.10%
Rate Base Secondary	RB-SEC	100.00%	47.82%	11.91%	40.27%
Rate Base Customer	RB-CS	100.00%	57.00%	27.84%	15.16%
Payroll Primary	PAY-PRI	100.00%	52.99%	0.05%	46.96%
Payroll Secondary	PAY-SEC	100.00%	53.07%	1.88%	45.05%
Payroll Customer	PAY-CS	100.00%	22.48%	65.27%	12.25%
Total Plant Primary	TOTPLT-PRI	100.00%	52.90%	0.00%	47.10%
Total Plant Secondary	TOTPLT-SEC	100.00%	46.49%	14.26%	39.25%
Total Plant Customer	TOTPLT-CS	100.00%	62.67%	27.25%	10.08%
Total Depreciation Primary	DPR-TOT-PRI	100.00%	52.89%	0.00%	47.11%
Total Depreciation Secondary	DPR-TOT-SEC	100.00%	48.48%	10.45%	41.07%
Total Depreciation Customer	DPR-TOT-CS	100.00%	55.21%	41.88%	2.91%
OH Plant Primary	OHPLT-PRI	100.00%	53.02%	0.00%	46.98%
OH Plant Secondary	OHPLT-SEC	100.00%	54.44%	0.00%	45.56%
OH Plant Customer	OHPLT-CS	0.00%	0.00%	0.00%	0.00%
Cash Working Capital Primary	CWC-PRI	100.00%	53.02%	0.00%	46.98%
Cash Working Capital Secondary	CWC-SEC	100.00%	53.14%	2.57%	44.29%
Cash Working Capital Customer	CWC-CS	100.00%	11.98%	87.73%	0.30%

Jersey Central Power & Light - First Energy Corp. Functional Factors	Code	Total	Primary	Secondary	Customer Service
EXTERNAL FUNCTIONAL FACTORS					
Total System	CUSTSERVICE	100.0%	0.0%	0.0%	100.0%
Account 360 Land and Land Rights	ACC360	100.0%	50.0%	50.0%	0.0%
Account 361 Structures and Improvements	ACC361	100.0%	50.0%	50.0%	0.0%
Account 362 Station Equipment	ACC362	100.0%	50.0%	50.0%	0.0%
Account 364 Poles, Towers & Fixtures	ACC364	100.0%	50.0%	50.0%	0.0%
Account 365 Overhead Conductors & Devices	ACC365	100.0%	50.0%	50.0%	0.0%
Account 366 Underground Conduit	ACC366	100.0%	90.0%	10.0%	0.0%
Account 367 Underground Conductors & Device	ACC367	100.0%	50.0%	50.0%	0.0%
580,590-591 Segmentation	S3-DISTO&M	100.0%	41.0%	59.0%	0.0%
Primary Distribution Only	PRIMARY	100.0%	100.0%	0.0%	0.0%
Secondary Distribution Only	SECONDARY	100.0%	0.0%	100.0%	0.0%
INTERNAL FUNCTIONAL FACTORS					
Total Distribution Plant Factor	DISTPLT	100.0%	33.7%	57.3%	9.0%
Total Utility Plant Factor	TOTPLT	100.0%	33.8%	55.9%	10.3%
Total General Plant Factor	GENPLT	100.0%	35.2%	36.0%	28.8%
Rate Base	RB	100.0%	35.1%	54.0%	11.0%
Dist. Exp excl. 587, 588, 598 Factor	DISTEXP	100.0%	45.3%	45.2%	9.5%
Total Operating Expenses excl. A&G Factor	OPEXP	100.0%	35.2%	35.2%	29.6%
Total Depreciation	TOTDEPR	100.0%	32.8%	52.8%	14.4%
Payroll Factor	PAYROLL	100.0%	35.2%	36.0%	28.8%
Payroll Factor (excl. A&G Expenses)	PAYROLLxAG	100.0%	35.2%	35.2%	29.6%
Overhead Plant (364, 365) Factor	OHPLT	100.0%	50.0%	50.0%	0.0%
INTERNAL FUNCTIONAL FACTORS DERIVATION					
Total Overhead Plant (364, 365)		2,064,639,186	1,032,319,593	1,032,319,593	-
Overhead Plant (364, 365) Factor	OHPLT	100.0%	50.0%	50.0%	0.0%
Total Distribution Plant		5,484,712,711	1,848,954,704	3,143,000,214	492,757,793
Total Distribution Plant Factor	DISTPLT	100.0%	33.7%	57.3%	9.0%
Total General Plant		255,260,286	89,806,497	91,908,263	73,545,526
Total General Plant Factor	GENPLT	100.0%	35.2%	36.0%	28.8%
Total Utility Plant		6,062,034,052	2,049,386,718	3,389,710,401	622,936,932
Total Utility Plant Factor	TOTPLT	100.0%	33.8%	55.9%	10.3%
Rate Base		2,987,495,271	1,047,606,020	1,612,375,756	327,513,495
Rate Base Factor	RB	100.0%	35.1%	54.0%	11.0%
Dist. Exp excl. 587, 588, 598		127,345,869	57,654,585	57,605,739	12,085,545
Dist. Exp excl. 587, 588, 598 Factor	DISTEXP	100.0%	45.3%	45.2%	9.5%
Total Operating Expenses excl. A&G		196,457,805	69,226,727	69,168,077	58,063,002
Total Operating Expenses excl. A&G Factor	OPEXP	100.0%	35.2%	35.2%	29.6%

Jersey Central Power & Light - First Energy Corp. Proposed Revenue Calculations	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
Distribution Revenues	$ 642,676,612	$ 349,755,697	$ 6,912,701	$ 207,791,273	$ 10,889,186	$ 27,242,693	$ 20,523,970		$ 19,253,942
Other Operating Revenues	12,445,306	6,167,765	89,288	4,961,917	238,373	727,039	103,174		157,405
Total Operating Revenues	**$ 655,121,918**	**$ 355,923,462**	**$ 7,001,989**	**$ 212,753,190**	**$ 11,127,559**	**$ 27,969,732**	**$ 20,627,144**		**$ 19,411,347**
Total O&M Expenses	$ 314,440,573	$ 198,134,578	$ 3,176,128	$ 88,783,489	$ 4,737,000	$ 10,650,683	$ 996,033		$ 7,923,579
Depreciation & Amortization	235,967,143	135,078,068	2,231,409	68,493,875	3,814,702	8,220,653	5,477,278		12,057,416
Total Taxes Other Than Income	8,917,602	5,457,634	88,589	2,601,324	142,001	260,852	49,276		314,224
Total Expenses	**$ 559,325,317**	**$ 338,670,280**	**$ 5,496,126**	**$ 159,878,688**	**$ 8,693,703**	**$ 19,132,187**	**$ 6,522,587**		**$ 20,295,219**
Income Before Taxes	**$ 95,796,600**	**$ 17,253,182**	**$ 1,505,863**	**$ 52,874,502**	**$ 2,433,856**	**$ 8,837,545**	**$ 14,104,557**		**$ (883,872)**
State Income Taxes	$ 2,708,787	$ (1,970,645)	$ 77,687	$ 2,993,028	$ 121,022	$ 634,625	$ 1,222,919		$ (336,153)
Federal Income Taxes	(999,034)	(8,206,994)	98,921	4,339,344	145,055	1,163,989	2,543,585		(1,006,728)
Total Income Taxes	**$ 1,709,753**	**$ (10,177,639)**	**$ 176,608**	**$ 7,332,372**	**$ 266,076**	**$ 1,798,613**	**$ 3,766,503**		**$ (1,342,882)**
Net Operating Income	**$ 94,086,848**	**$ 27,430,821**	**$ 1,329,255**	**$ 45,542,130**	**$ 2,167,779**	**$ 7,038,931**	**$ 10,338,054**		**$ 459,010**
Rate Base	**$ 2,987,495,271**	**$ 1,780,213,130**	**$ 29,223,805**	**$ 892,108,172**	**$ 49,527,326**	**$ 81,221,085**	**$ 23,489,892**		**$ 129,649,572**
Rate of Return	3.15%	1.54%	4.55%	5.11%	4.38%	8.67%	44.01%		0.35%
Existing Unitized Rate of Return		**0.49**	**1.44**	**1.62**	**1.39**	**2.75**	**13.97**		**0.11**
Rate Increase with Equal Rates of Return									
Required Rate of Return	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%	7.60%		7.60%
Required Net Operating Income	$ 227,049,641	$ 135,296,198	$ 2,221,009	$ 67,800,221	$ 3,764,077	$ 6,172,802	$ 1,785,232		$ 9,853,367
Change in Net Operating Income	$ 132,962,793	$ 107,865,377	$ 891,754	$ 22,258,091	$ 1,596,297	$ (866,129)	$ (8,552,822)		$ 9,394,358
Change in Distribution Revenue	$ 184,953,113	$ 150,042,255	$ 1,240,443	$ 30,961,318	$ 2,220,472	$ (1,204,798)	$ (11,897,096)		$ 13,067,684
Rate Increase Using Current Unitized ROR									
Current Unitized ROR	1.00	0.49	1.44	1.62	1.39	2.75	13.97		0.11
Required Rate of Return	7.60%	3.72%	10.98%	12.32%	10.56%	20.91%	106.21%		0.85%
Required Net Income	$ 227,049,641	$ 66,195,841	$ 3,207,748	$ 109,901,910	$ 5,231,268	$ 16,986,294	$ 24,947,710		$ 1,107,678
Change in Net Operating Income	$ 132,962,793	$ 38,765,020	$ 1,878,493	$ 64,359,780	$ 3,063,489	$ 9,947,363	$ 14,609,657		$ 648,669
Change in Distribution Revenue	$ 184,953,113	$ 53,922,688	$ 2,613,010	$ 89,525,358	$ 4,261,356	$ 13,836,921	$ 20,322,237		$ 902,307
Rate Change as Requested									
Change in Distribution Revenue	$ 184,953,113	**$ 100,654,674**	**$ 1,989,376**	**$ 61,957,464**	**$ 3,246,846**	**$ 8,122,998**	**$ 6,119,666**		**$ 2,770,504**
Requested Distribution Revenue	$ 827,629,725	$ 450,410,371	$ 8,902,078	$ 269,748,737	$ 14,136,032	$ 35,365,691	$ 26,643,636		$ 22,024,446
Requested Distribution Revenue Inc/(Dec)	28.78%	28.78%	28.78%	29.82%	29.82%	29.82%	29.82%		14.39%
Requested Net Operating Income	$227,049,641	$99,791,466	$2,759,418	$90,083,351	$4,501,937	$12,878,555	$14,737,482		$2,450,725
Requested Rate of Return	**7.60%**	**5.61%**	**9.44%**	**10.10%**	**9.09%**	**15.86%**	**62.74%**		**1.89%**
Requested Unitized ROR	1.00	0.74	1.24	1.33	1.20	2.09	8.26		0.25

Jersey Central Power & Light - First Energy Corp. Revenue Requirements by Cost Classification (Proposed Rates)	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
Demand									
Rate Base	1,511,873,505	904,729,591	12,671,470	420,675,060	19,297,201	25,814,803	5,982,640		121,963,581
Required Return on Rate Base	7.60%	5.61%	9.44%	10.10%	9.09%	15.86%	62.74%		1.89%
Required Net Income	$ 106,242,180	$ 50,715,440	$ 1,196,486	$ 42,478,951	$ 1,754,078	$ 4,093,240	$ 3,753,489		$ 2,305,439
Total Operating Expenses	139,783,369	86,002,630	1,188,149	40,023,425	1,847,732	3,527,102	114,443		7,067,920
Depreciation & Amortization	120,591,256	69,599,004	984,722	32,427,953	1,483,275	2,640,694	1,768,583		11,468,515
Total Other Taxes	4,272,218	2,590,826	36,063	1,203,173	55,288	84,293	10,489		290,790
Total Expenses	$ 264,646,842	$ 158,192,460	$ 2,208,934	$ 73,654,551	$ 3,386,294	$ 6,252,088	$ 1,893,516		$ 18,827,226
Interest Expense	33,248,094	19,896,198	278,662	9,251,200	424,371	567,702	131,566		2,682,140
Income Taxes	28,541,713	12,050,757	358,882	12,992,517	519,934	1,378,535	1,416,223		(147,295)
Income Tax Amortization	(4,752,127)	(2,843,750)	(39,829)	(1,322,268)	(60,655)	(81,141)	(18,805)		(383,356)
Revenue Requirement (Demand)	$ 394,678,608	$ 218,114,907	$ 3,724,473	$ 127,803,751	$ 5,599,651	$ 11,642,721	$ 7,044,423		$ 20,602,013
Less: Other Revenues (Demand)	$ 8,352,095	$ 3,942,566	$ 43,460	$ 3,569,762	$ 148,236	$ 419,518	$ 98,542		$ 129,668
Base Revenue Requirement (Demand)	**$ 386,326,513**	**$ 214,172,340**	**$ 3,681,013**	**$ 124,233,990**	**$ 5,451,415**	**$ 11,223,203**	**$ 6,945,881**		**$ 20,472,345**
Customer									
Rate Base	283,270,613	235,325,314	3,270,043	30,087,631	262,498	7,163,868	7,042,301		43,041
Required Return on Rate Base	7.60%	5.61%	9.44%	10.10%	9.09%	15.86%	62.74%		1.89%
Required Net Income	$ 22,111,597	$ 13,191,375	$ 308,769	$ 3,038,191	$ 23,861	$ 1,135,915	$ 4,418,317		$ 814
Total Operating Expenses	59,274,482	50,620,540	712,637	6,522,984	26,160	569,875	697,341		119,140
Depreciation & Amortization	19,717,933	16,153,879	223,265	2,059,566	22,375	635,456	616,665		-
Total Other Taxes	1,219,140	1,030,731	14,431	132,302	761	18,947	20,258		1,512
Total Expenses	$ 80,211,555	$ 67,805,150	$ 950,332	$ 8,714,852	$ 49,296	$ 1,224,278	$ 1,334,265		$ 120,653
Interest Expense	6,229,495	5,175,114	71,913	661,667	5,773	157,543	154,869		947
Income Taxes	6,210,125	3,134,470	92,614	929,254	7,073	382,557	1,667,068		(52)
Income Tax Amortization	(890,377)	(739,676)	(10,278)	(94,572)	(825)	(22,518)	(22,135)		(135)
Revenue Requirement (Customer)	$ 107,642,900	$ 83,391,319	$ 1,341,438	$ 12,587,725	$ 79,404	$ 2,720,233	$ 7,397,514		$ 121,279
Less: Other Revenues (Customer)	$ 51,371	$ 36,640	$ 1,118	$ 12,581	$ 106	$ 412	$ 510		$ -
Base Revenue Requirement (Customer)	**$ 107,591,529**	**$ 83,354,679**	**$ 1,340,320**	**$ 12,575,144**	**$ 79,298**	**$ 2,719,821**	**$ 7,397,004**		**$ 121,279**

Jersey Central Power & Light - First Energy Corp. Revenue Requirements by Cost Classification (Proposed Rates)	Total Company	Residential Service RS	Residential Time of Day RT	General Service GS	General Time of Day GST	General Service Pri GP	General Service Trans GT	[redacted]	Lighting LTG
Energy									
Rate Base	1,192,351,152	640,158,225	13,282,293	441,345,482	29,967,626	48,242,415	10,464,951		7,642,950
Required Return on Rate Base	7.60%	5.61%	9.44%	10.10%	9.09%	15.86%	62.74%		1.89%
Required Net Income	$ 98,695,864	$ 35,884,652	$ 1,254,162	$ 44,566,210	$ 2,723,999	$ 7,649,400	$ 6,565,676		$ 144,472
Total Operating Expenses	115,382,722	61,511,408	1,275,342	42,237,081	2,863,108	6,553,706	184,249		736,518
Depreciation & Amortization	95,657,954	49,325,186	1,023,421	34,006,355	2,309,052	4,944,503	3,092,029		588,901
Total Other Taxes	3,426,244	1,836,076	38,096	1,265,849	85,952	157,612	18,529		21,921
Total Expenses	$ 214,466,920	$ 112,672,670	$ 2,336,860	$ 77,509,285	$ 5,258,112	$ 11,655,820	$ 3,294,807		$ 1,347,340
Interest Expense	26,221,376	14,077,924	292,095	9,705,770	659,028	1,060,914	230,138		168,079
Income Taxes	28,338,543	8,526,737	376,182	13,630,922	807,433	2,576,191	2,477,284		(9,230)
Income Tax Amortization	(3,747,803)	(2,012,148)	(41,749)	(1,387,239)	(94,194)	(151,636)	(32,893)		(24,023)
Revenue Requirement (Energy)	$ 337,753,523	$ 155,071,910	$ 3,925,455	$ 134,319,178	$ 8,695,350	$ 21,729,775	$ 12,304,874		$ 1,458,559
Less: Other Revenues (Energy)	$ 4,041,839	$ 2,188,558	$ 44,710	$ 1,379,574	$ 90,030	$ 307,109	$ 4,122		$ 27,737
Base Revenue Requirement (Energy)	**$ 333,711,684**	**$ 152,883,352**	**$ 3,880,745**	**$ 132,939,603**	**$ 8,605,320**	**$ 21,422,667**	**$ 12,300,752**		**$ 1,430,822**

scottmadden
MANAGEMENT CONSULTANTS

Resume and Testimony Listing of:
Timothy S. Lyons
Partner

Summary of Qualifications

Tim Lyons is a partner with ScottMadden with more than 30 years of experience in the energy industry. Tim has held senior positions at several gas utilities and energy consulting firms. His experience includes rates and regulatory support, sales and marketing, customer service, and strategy development.

Prior to joining ScottMadden, Tim served as Vice President of Sales and Marketing for Vermont Gas. He has also served as Vice President of Marketing and Regulatory Affairs for Providence Gas Company, Director of Rates at Boston Gas Company, and Project Director at Quantec, LLC, an energy consulting firm.

Tim has sponsored testimony and evidence before 22 state regulatory commissions and 2 Canadian regulatory boards. Tim holds a bachelor's degree from St. Anselm College, a master's degree in Economics from The Pennsylvania State University, and a master's degree in Business Administration from Babson College.

Areas of Specialization

Regulation and Rates
Retail Energy
Utilities
Natural Gas

Capabilities

Regulatory Strategy and Rate Case Support
Strategic and Business Planning
Capital Project Planning
Process Improvements

Articles and Speeches

- "Country Strong: Vermont Gas shares its comprehensive effort to expand natural gas service into rural communities." ***American Gas Association***, June 2011 (with Don Gilbert).
- "Talking Safety With Vermont Gas." ***American Gas Association***, February 2009 (with Dave Attig).
- "Consumers Say 'Act Now' To Stabilize Prices." ***Power & Gas Marketing***, September/ October 2001 (with Jim DeMetro and Gerry Yurkevicz).
- "Rate Reclassification: Who Buys What and When." ***Public Utilities Fortnightly***, October 15, 1991 (with John Martin).

Sponsor	Date	Docket No.	Subject
Regulatory Commission of Alaska			
Cook Inlet Natural Gas Storage Alaska, LLC	7/21	Docket No. U-21-058	Sponsored testimony supporting the lead-lag study/cash working capital requirement for a general rate case proceeding.
ENSTAR Natural Gas Company	06/16	Docket No. U-16-066	Adopted and sponsored testimony supporting a lead-lag study for a general rate case proceeding.
Arizona Public Service Commission			
Southwest Gas Corporation	12/21	Docket No. G-01551A-21-0368	Sponsored testimony supporting class cost of service, rate design and bill impact analysis for a general rate case proceeding.
Arkansas Public Service Commission			
Liberty Utilities (Pine Bluff Water)	10/18	Docket No. 18-027-U	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding.
California Public Utilities Commission			
Liberty Utilities (CalPeco Electric)	5/21	Docket No. A 21-05-017	Sponsored testimony supporting the lead-lag study/cash working capital, marginal cost study, rate design and bill impact analysis for a general rate case proceeding.
Southwest Gas Corporation (Southern California, Northern California and South Lake Tahoe jurisdictions)	8/19	Docket No. A.19-08-015	Sponsored testimony on behalf of three separate rate jurisdictions supporting revenue requirements, lead-lag/ cash working capital, and class cost of service, rate design and bill impact analysis for a general rate case proceeding.
Connecticut Public Utilities Regulatory Authority			
Yankee Gas Company	07/14	Docket No. 13-06-02	Sponsored report and testimony supporting the review and evaluation of gas expansion policies, procedures and analysis.
Illinois Commerce Commission			
Liberty Utilities (Midstates Natural Gas)	07/16	Docket No. 16-0401	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new commercial classes and a decoupling mechanism.
Iowa Utilities Board			
Liberty Utilities (Midstates Natural Gas)	07/16	Docket No. RPU-2016-0003	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new commercial classes.
Kansas Corporation Commission			
The Empire District Electric Company	12/18	Docket No. 19-EPDE-223-RTS	Sponsored testimony supporting cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.
Maine Public Utilities Commission			
Maine Water Company	03/21	Docket No. 2021-00053	Sponsored testimony supporting a proposed rate smoothing mechanism.
Northern Utilities, Inc. d/b/a Unitil	06/19	Docket No. 2019-00092	Sponsored testimony supporting a proposed capital investment cost recovery mechanism.
Northern Utilities, Inc. d/b/a Unitil	06/15	Docket No. 2015-00146	Sponsored testimony supporting the proposed gas expansion program, including a zone area surcharge.

Sponsor	Date	Docket No.	Subject
Maryland Public Service Commission			
Sandpiper Energy, a Chesapeake Utilities company	12/15	Case No. 9410	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new residential and commercial classes.
Massachusetts Department of Public Utilities			
Berkshire Gas Company, Eversource Energy, Liberty Utilities, National Grid, and Unitil	03/22	Docket No. DPU 20-80	Sponsored report that summarizes research, findings and recommendations for regulatory mechanisms, methodologies, and policies that support Massachusetts's achievement of its net zero climate goal by 2050. The regulatory designs were informed by the results of quantitative and qualitative analysis of decarbonization pathways to achieve the Commonwealth's climate goals.
Liberty Utilities (New England Gas Company)	08/20	Docket No. DPU 20-92	Sponsored the Long-Range Forecast and Supply Plan filing for the five-year forecast period 2020/2021 through 2024/2025.
Eversource Energy, National Grid, and Unitil	02/20	Docket No. DPU 19-55	Sponsored report that summarizes research and evaluation of funding approaches for infrastructure modifications that interconnect Distributed Generation (DG) projects.
Liberty Utilities (New England Gas Company)	07/18	Docket No. DPU 18-68	Sponsored the Long-Range Forecast and Supply Plan filing for the five-year forecast period 2018/2019 through 2022/2023.
Liberty Utilities (New England Gas Company)	07/16	Docket No. DPU 16-109	Sponsored the Long-Range Forecast and Supply Plan filing for the five-year forecast period 2016/2017 through 2020/2021.
Boston Gas	10/93	Docket No. DPU 92-230	Sponsored testimony describing the Company's position regarding rate treatment of vehicular natural gas investments and expenses.
Boston Gas	03/90	Docket No. DPU 90-55	Sponsored testimony supporting the weather and other cost of service adjustments, rate design and customer bill impact studies for a general rate case proceeding.
Boston Gas	03/88	Docket No. DPU 88-67-II	Sponsored testimony supporting the rate reclassification of commercial and industrial customers for a rate design proceeding.
Michigan Public Service Commission			
Lansing Board of Water & Light and Michigan State University	04/20	Docket No. U-20650	Sponsored testimony evaluating Consumer Energy's cost of service and rate design proposals.
Lansing Board of Water & Light and Michigan State University	04/19	Docket No. U-20322	Sponsored testimony evaluating Consumer Energy's cost of service and rate design proposals.
Midland Cogeneration Ventures, LLC	09/18	Docket No. U-18010	Sponsored testimony evaluating Consumer Energy's cost of service and rate design proposals.
Minnesota Public Utilities Commission			
Northern States Power Company (XcelEnergy)	10/21	Docket No. E002/GR-21-630	Sponsored testimony supporting a Return on Equity (ROE)adjustment mechanism that would allow the Company to symmetrically adjust its ROE to reflect significant changesin financial market conditions.

Sponsor	Date	Docket No.	Subject
Missouri Public Service Commission			
The Empire District Gas Company	08/21	Docket No. GR-2021-0320	Sponsored testimony supporting the cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.
The Empire District Electric Company	05/21	Docket No. ER-2021-0312	Sponsored testimony supporting the cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.
Spire Missouri, Inc.	12/20	Docket No. GR-2021-0108	Sponsored testimony supporting class cost of service, rate design, and lead-lag study proposals for a general rate case proceeding. The testimony also included support for a proposed revenue adjustment mechanism.
The Empire District Electric Company	08/19	Docket No. ER-2019-0374	Sponsored testimony supporting the cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding. The testimony also included proposals for a weather normalization mechanism.
Liberty Utilities (Midstates Natural Gas)	09/17	Docket No. GR-2018-0013	Sponsored testimony supporting the cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding. The testimony also included proposals for a revenue decoupling/ weather normalization mechanism as well as tracker accounts for certain O&M expenses and capital costs.
Missouri Gas Energy	04/17	Docket No. GR-2017-0216	Sponsored testimony supporting the cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding. The testimony included support for a decoupling mechanism.
Laclede Gas Company	04/17	Docket No. GR-2017-0215	Sponsored testimony supporting the cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding. The testimony included support for a decoupling mechanism.
Nevada Public Utilities Commission			
Southwest Gas Corporation	09/21	Docket No. 21-09001	Sponsored testimony supporting the class cost of service,rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
Southwest Gas Corporation	02/20	Docket No. 20-02023	Sponsored testimony supporting the class cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
New Hampshire Public Utilities Commission			
Unitil (Northern Utilities, Inc.)	8/21	Docket No. DG 21-104	Sponsored testimony supporting a revenue decoupling mechanism.
Unitil Energy Systems, Inc.	4/21	Docket No. DE 21-030	Sponsored testimony supporting a revenue decoupling mechanism.
Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities	11/17	Docket No. DG 17-198	Sponsored testimony supporting a levelized cost analysis for approval of firm supply and transportation agreements.
Liberty Utilities d/b/a Granite State Electric Company	04/16	Docket No. DE 16-383	Adopted testimony and sponsored Lead/Lag study for a general rate case proceeding.
New Jersey Board of Public Utilities			
South Jersey Gas Company	04/22	Docket No. GR22040253	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Elizabethtown Gas Company	12/21	Docket No. GR21121254	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.

Sponsor	Date	Docket No.	Subject
South Jersey Gas Company	03/20	Docket No. GR20030243	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Elizabethtown Gas Company	04/19	Docket No. GR19040486	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Pivotal Utility Holdings, Inc. d/b/a Elizabethtown Gas Company	08/16	Docket No. GR16090826	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Corporation Commission of Oklahoma			
The Empire District Electric Company	02/21	Cause No. PUD 202100163	Sponsored testimony supporting the cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
The Empire District Electric Company	03/19	Cause No. PUD 201800133	Sponsored testimony supporting the cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
The Empire District Electric Company	04/17	Cause No. PUD 201600468	Adopted direct testimony and sponsored rebuttal testimony supporting the revenue requirements for a general rate case proceeding. The testimony included proposals for alternative ratemaking mechanisms.
Rhode Island Public Utilities Commission			
Providence Gas Company	08/01 09/00 08/96	Docket No. 1673	Sponsored testimony supporting the changes in cost of gas adjustment factor related to projected under-recovery of gas costs; Filed testimony and witness for pilot hedging program to mitigate price risks to customers; Filed testimony and witness for changes in cost of gas adjustment factor related to extension of rate plan.
Providence Gas Company	08/00	Docket No. 2581	Sponsored testimony supporting the extension of a rate plan that began in 1997 and included certain modifications, including a weather normalization clause.
Providence Gas Company	03/00	Docket No. 3100	Sponsored testimony supporting the de-tariff and deregulation of appliance repair service, enabling the Company to have needed pricing flexibility.
Providence Gas Company	06/97	Docket No. 2581	Sponsored testimony supporting a rate plan that fixed all billing rates for three-year period; included funding for critical infrastructure investments in accelerated replacement of mains and services, digitized records system, and economic development projects.
Providence Gas Company	04/97	Docket No. 2552	Sponsored testimony supporting the rate design, customer bill impact studies and retail access tariffs for commercial and industrial customers, including redesign of cost of gas adjustment clause, for a rate design proceeding.
Providence Gas Company	02/96	Docket No. 2374	Sponsored testimony supporting the rate design, customer bill impact studies and retail access tariffs for largest commercial and industrial customers for a rate design proceeding.

Sponsor	Date	Docket No.	Subject
Providence Gas Company	01/96	Docket No. 2076	Sponsored testimony supporting the rate reclassification of customers into new rate classes, rate design (including introduction of demand charges), and customer bill impact studies for a rate design proceeding.
Providence Gas Company	11/92	Docket No. 2025	Sponsored testimony supporting the Integrated Resource Plan filing, including a performance-based incentive mechanism.
Railroad Commission of Texas			
Texas Gas Service Company – West Texas, North Texas, Borger/ Skellytown Service Areas	06/22	CASE No. 9896	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – Central Texas and Gulf Coast Service Areas	12/19	GUD No. 10928	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
CenterPoint Energy – Beaumont/ East Texas Division	11/19	GUD No. 10920	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – Borger/ Skellytown Service Area	08/18	GUD No. 10766	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – North Texas Service Area	06/18	GUD No. 10739	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
CenterPoint Energy – South Texas Division	11/17	GUD No. 10669	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – Rio Grande Valley Service Area	06/17	GUD No. 10656	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Atmos Pipeline – Texas	01/17	GUD No. 10580	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
CenterPoint Energy – Texas Gulf Division	11/16	GUD No. 10567	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Public Utility Commission of Texas			
CenterPoint Energy Houston Electric, LLC	04/19	Docket No. 49421	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Vermont Public Utilities Commission			
Vermont Gas Systems	12/12	Docket No. 7970	Sponsored testimony describing the market served by $90 million natural gas expansion project to Addison County, VT. Also described the terms and economic benefits of a special contract with International Paper.
Vermont Gas Systems	02/11	Docket No. 7712	Sponsored testimony supporting the market evaluation and analysis for a system expansion and reliability regulatory fund.
Virginia State Corporation Commission			
American Electric Power - Appalachian Power Company	3/20	Case No. PUR-2020-00015	Sponsored testimony supporting the Lead/Lag study for the 2020 triennial review of base rates, terms, and conditions.
Nova Scotia Utility and Review Board			
Nova Scotia Power	01/22	Matter No. M10431	Sponsored evidence supporting the cash working capital requirement and lead/Lag study for a general rate case proceeding.

Sponsor	Date	Docket No.	Subject
Ontario Energy Board			
Ontario Energy Association	01/21	Docket No. EB-2020-0133	Sponsored evidence regarding policies and ratemaking treatment related to COVID-19 costs in U.S. and Canadian regulatory jurisdictions. The evidence was used to support Ontario Energy Association's response to Staff's proposals

EXHIBIT JC-9

BEFORE THE
NEW JERSEY BOARD OF PUBLIC UTILITIES

In the Matter of the Verified Petition of Jersey Central Power & Light Company for Review and Approval of Increases in, and Other Adjustments to, Its Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith

Direct Testimony

of

Yongmei Peng

Re: Tariff Revisions and Design of the Proposed Distribution Rates

I. INTRODUCTION AND BACKGROUND

Q. Please state your name and business address.

A. My name is Yongmei Peng and my business address is 300 Madison Avenue, Morristown, NJ 07962.

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

A. I am employed by FirstEnergy Service Company as an Analyst V – Rates & Regulatory Affairs, New Jersey.

Jersey Central Power & Light Company ("JCP&L" or the "Company") is an operating company subsidiary of FirstEnergy Corp., and an affiliate of FirstEnergy Service Company ("FESC"). In my current position at FESC, I am responsible for developing retail distribution rates for JCP&L, as well as rates for recovery of basic generation service and transmission costs. I also provide analytical support for all regulatory filings and for the implementation of all rate changes to the JCP&L Tariff for Service (the "Tariff").

Q. Please briefly describe your educational and professional background.

A. In my current role, I am responsible for: (1) all analysis and design of JCP&L's retail rates related to the recovery of costs for distribution, basic generation, and transmission services, (2) customer impact analysis for all regulatory petitions, (3) tariff changes, updates, and associated compliance filings with the Board, and (4) rates implementation, interpretation, and application for JCP&L. I have held this position since May 2005.

Prior to my current position, I was employed by JCP&L from May 1995 through April 2005 as a Business Analyst in the Company's Energy Efficiency Group working on New Jersey Clean Energy Programs from 1997 through April 2005, and, prior to 1997, on Demand Side Management ("DSM") Programs. My responsibilities included maintaining

various measurement and meter information databases, implementing the statewide Measurement and Verification Protocol and evaluating energy and revenue impacts of all conservation programs.

From September 1993 through April 1995, I was employed by Honeywell DMC Services, LLC to work for JCP&L as a database administrator of JCP&L's proprietary commercial and industrial DSM program tracking system. I was also accountable for all measurement data tracking and reporting for the residential DSM programs.

I graduated from Stevens Institute of Technology in 1993 with a Master of Science degree in Management Information Systems.

Q. Have you previously testified in proceedings before the New Jersey Board of Public Utilities ("Board" or "BPU")?

A. Yes. In my current position, I have previously provided written testimony that was filed with the Board. More specifically, I was the witness on the subjects of Rate Design/Tariff Issues, Proof of Revenues, and Customer Impacts in *I/M/O the Verified Petition of Jersey Central Power & Light Company For Review and Approval of Increases in, and Other Adjustments to, Its Rates and Charges for Electric Services, and for Approval of Other Proposed Tariff Revisions in Connection Therewith* ("2020 Base Rate Filing") at BPU Docket No. ER20020146. Additionally, I was the witness on the subjects of Proof of Revenues and Customer Impacts in *I/M/O the Verified Petition of Jersey Central Power & Light Company For Review and Approval of Increases in, and Other Adjustments to, Its Rates and Charges for Electric Services, and for Approval of Other Proposed Tariff Revisions in Connection Therewith* ("2016 Base Rate Filing") at BPU Docket No. ER16041383.

Q. Please describe the purpose of your direct testimony.

A. The purpose of my testimony is two-fold. First, I will explain certain modifications that the Company is proposing to its Tariff. For purposes of clarity, I should explain that the Company's current BPU No. 13 Electric - Tariff for Service is referenced in my testimony as the "current tariff". The terms and conditions of the current tariff took effect on December 1, 2020 with rates effective on November 1, 2021. After the conclusion of this proceeding, a new tariff will be prepared, which will be entitled "Tariff for Service, BPU No. 14 Electric" and is referred to herein as the "proposed tariff." The Company's proposed tariff revisions are depicted as modifications to the current tariff in Schedule YP-1. The meaning of generic references to the "tariff" only (where "current" or "proposed" are not specified) can be determined from the context. Second, I will discuss the interclass and intraclass rate design of the distribution rates to produce revenues equal to the Company's proposed revenue requirement. As part of my discussion of rate design, I also will address customer impacts.

Q. Please summarize your testimony.

A. My testimony will describe the modifications the Company is proposing to Part I (General Information), Part II (Standard Terms and Conditions) and Part III (Service Classifications and Riders) of the Tariff for Service.

In Part I, the Company is proposing modification to subpart G – Municipalities Served.

For Part II – Standard Terms and Conditions, the Company is proposing modification to Section 3.01 per N.J.A.C. 14:3-7.8(b). Secondly, the Company is revising several subsections under Section 12 – Net Metering Installations and Section 13 –

Community Solar Energy Pilot Program. Finally, the Company is also proposing to update Appendix A – Unit Costs of Underground Construction.

With respect to Part III, in addition to proposing rate changes that update all service classifications, the Company is proposing to increase the Field Collection Charge and decrease the Reconnection Charge for customers under Service Classifications RS – Residential Service ("RS"), RT – Residential Time-of Day Service ("RT"), RGT – Residential Geothermal & Heat Pump Service ("RGT") , GS – General Service Secondary ("GS") and GST – General Service Secondary Time-of-Day ("GST"). Also, the Company is proposing to update Rider QFS – Cogeneration and Small Power Production Service to recognize an exemption received from the Federal Energy Regulatory Commission ("FERC") with respect to the Company's mandatory purchase obligations from qualifying facilities ("QFs") of a certain size under the Public Utility Regulatory Policies Act of 1978 ("PURPA").

My testimony will also discuss the Company's proposed distribution rate design, provide the proof of revenues supporting the results of the Company's rate design process, and demonstrate that the total requested revenue requirement from the Company's Cost of Service Study ("COSS") is properly accounted for. Finally, my testimony will present customer impacts resulting from the Company's proposed distribution rate changes.

Q. Please describe the attachments to your testimony.

A. The following schedules are attached to my testimony:

(i) Schedule YP-1 contains the current and proposed tariffs. For convenience, Parts I, II and III of the current tariff are being provided in their entirety. Parts I, II and III of the proposed tariff are also provided and incorporate all of the Company's

proposed changes with the tariff sheets renumbered to preliminarily conform to the way they will appear in Tariff for Service BPU No. 14 Electric, when it is filed at the conclusion of this proceeding.

(ii) Schedule YP-2 provides a summary of JCP&L's distribution revenue requirement and the proposed increase by rate class as derived from the Company's COSS.

(iii) Schedule YP-3 provides a summary proof comparing JCP&L's COSS-derived distribution revenue requirements to the Company's proposed distribution revenues.

(iv) Schedule YP-4 contains JCP&L's proof of revenues by tariff rate class for all Company distribution tariff rate components.

(v) Schedule YP-5 provides the Company's customer impact analysis by tariff rate class.

II. PROPOSED TARIFF CHANGES

Q. Please describe the changes that are proposed for Parts I and II of the current tariff and the reasons for such changes.

A. For Part I – General Information, subpart G – Municipalities Served: The Company is correcting the spelling of Southhampton Twp. to Southampton Twp. in BURLINGTON COUNTY and Wallpack Twp. to Walpack Twp. in SUSSEX COUNTY.

For Part II - Standard Terms and Conditions:

1. Section 3 – Billings, Payments, Credit Deposits & Metering:

   a. Subsection 3.01 Measurement of Electricity Consumption: The Company is proposing to add an additional exception consistent with the Board's regulations at N.J.A.C. 14:3-7.8(b): "(ii) the electric service registered on

such meter was delivered outside the tenant-customer's premises without the tenant-customer's permission (N.J.A.C. 14:3-7.8(b))" to the general rule that the meter registration is conclusive as measuring the quantity of service received by the Customer.

2. Sections 12 – Net Metering Installations:

   a. Subsection 12.03 Limitations and Qualifications for Aggregated Net Metering (N.J.S.A. 48:3-87e(4)): The Company is proposing an additional reference to "N.J.A.C. 14:8-7". For part (b) Billing for Aggregated Net Metering of this Subsection, the Company is correcting the reference from "Section 12.06" to "Section 12.07."

3. Section 13 – Community Solar Energy Pilot Program: The Company is proposing to add a reference link to the Company's website for additional details about JCP&L's subscription process in Subsection 13.03 entitled "Subscription Requirements."

4. Appendix A – Unit Costs of Underground Construction: The direct testimony of Mr. Dennis M. Pavagadhi (Exhibit JC-05) discusses, among other things, the details of the proposed changes to Appendix A.

Q. Please describe the changes that are proposed for the Part III – Service Classifications and Riders of the current tariff and the reasons for such changes.

A. The Company is proposing the following modifications to the service classifications and riders set forth in Part III of the current tariff:

1. <u>Field Collection Charge</u> – The current Field Collection Charge of $25 was approved by the Board in the 2012 Base Rate Case (BPU Docket No. ER12111052) and took

effect on April 1, 2015. For this proceeding, the Company has updated the cost analysis on all activities to collect its costs and, therefore, is proposing an increase to the Field Collection Charge from $25 to $35 for each collection visit for customers under Service Classifications RS, RT, RGT, GS and GST. The reason for this proposed increase is increases in wages and average time spent in field visits, business office planning and scheduling, and handling call center inquiries. Please see Table 1, which provides the result of the cost analysis and serves as the basis upon which the Company has proposed this increase.

Table 1 - Field Collection Charge

Field Visit - Labor		
Wage per Hour - Field Collector (bargaining)	Average Time in Minutes Per field visit (includes drive time)	Cost Per Field Visit
$36.73	30	$18.37
Business Office - Planning, Scheduling & Field Inquiries		
Wage per hour - Customer Service Rep - Level 3 (bargaining)	Average Time in Minutes Per Field Inquiry/re-disconnection	Cost per inquiry
$34.65	5.5	$3.18
Customer Care Center - Credit Inquiries		
Average wage per hour - Customer Service Assoicate	Average Time in Minutes Per Inquiry	Cost per inquiry
$18.99	5.5	$1.74
Supervision Expense (non-bargaining)		$1.18
TOTAL LABOR COSTS		**$24.47**
Field Reconnection-Transportation		
Average Company Vehicle Cost per mile	Average mileage per field visit	Cost Per Field Visit
$0.96	5	$4.80
Overhead (labor related) Expense		
$2.92	Overheads at 45.03% non-bargaining	$1.32
$21.55	Overheads at 38.47% bargaining	$8.29
$24.47	**Total:**	**$9.61**
TOTAL COST-BASED CHARGE		**$38.88**
	Current charge	$25.00
	Proposed Charge	**$35.00**

2. Reconnection Charge – The current Reconnection Charge of $45 was approved by the Board in 2012 Base Rate Case (BPU Docket No. ER12111052) and took effect

on April 1, 2015. Based on updated cost analysis for this current proceeding, while wages for field reconnection, business office and call centers are increasing, time spent and distance traveled for reconnection are decreasing due to scheduling optimization. In addition, an anti-device lock, used only in cases of tampering, is substituted with a much cheaper plastic seal for disconnection. Thus, the Company is proposing to decrease the Reconnection Charge from $45 to $35 for customers under Service Classifications of RS, RT, RGT, GS and GST. Please see Table 2, which provides the result of the cost analysis and serves as the basis upon which the Company proposes a decrease.

Table 2 - Reconnection Charge

Field Reconnection - Labor		
Average wage per Hour - Field Collector (bargaining)	Average Time in Minutes Per Reconnection (includes drive time)	Cost Per Reconnection
$36.73	20	$12.24
Business Office - Dispatching & Field Inquiries		
Average wage per hour - Customer Service Rep - Level 3 (bargaining)	Average Time in Minutes Per Field Inquiry/dispatching	Cost per Inquiry
$34.65	7	$4.04
Customer Care Center -Negotiation & starting reconnection process		
Average wage per hour - Customer Service Assoicate	Average Time in Minutes Per Inquiry	Cost per Inquiry
$18.99	5.5	$1.74
Supervision Expense (non-bargaining)		$1.18
TOTAL LABOR COSTS		**$19.20**
Field Reconnection-Transportation		
Average Company Vehicle Cost per mile	Average miles per reconnection	Cost per reconnection
$0.96	5	$4.80
Supplies - Seals		
Seal Cost	Seals per reconnection process	Cost per reconnection
$0.33	2	$0.66
Overhead (labor related) Expense		
$2.92	Overheads at 45.03% non-bargaining	$1.32
$16.28	Overheads at 38.47% bargaining	$6.26
$19.20	**Total:**	**$13.04**
TOTAL COST-BASED CHARGE		**$37.70**
	Cost-based Charge	$37.70
	Current charge	$45.00
	Proposed Charge	**$35.00**

3. Service Classification SVL – Sodium Vapor Street Lighting Service:

The Company is proposing to sunset the Sodium Vapor Street Lighting Service due to a lack of availability and the cost of replacement equipment. Please refer to the direct testimony of Mr. Mark A. Mader (Exhibit JC-02) for additional discussion regarding this proposed change.

4. Service Classification LED – LED Street Lighting Service:

The Company is proposing to provide optional LED connected street lighting service (*i.e.*, smart streetlights) to its customers on an individual basis by special contract. Please refer to direct testimony of Mr. Mark A. Mader (Exhibit JC-2) for additional discussion regarding this proposed change.

5. Rider QFS – Cogeneration and Small Power Production Service:

In 2021, believing that certain QFs have sufficient market power and can offer directly into the PJM Interconnection, LLC ("PJM") market, FESC, acting on behalf of the FirstEnergy's utility companies, including JCP&L, sought and received an exemption from FERC (Docket No. QM22-4-000, dated December 17, 2021) with respect to JCP&L's obligations under PURPA to purchase from QFs that are greater than 5 MW for small power production facilities and 20 MW for cogeneration facilities within PJM. As set forth in the proposed tariff, JCP&L proposes to clarify Rider QFS as it pertains to the exemption authorized by FERC.

III. DESIGN OF THE COMPANY'S PROPOSED DISTRIBUTION RATES

Q. Please describe the fundamental goal applied in designing the proposed distribution rates in this proceeding.

A. Cost causation is the overriding principle that guides the rate design; specifically, rate structure should reflect the underlying cost structure with rates at a level sufficient to permit the Company to recover its revenue requirement. Electricity rates should also reflect the costs of service to appropriately convey the underlying costs to customers in an understandable manner that ensures the efficient use of resources and promotes greater customer satisfaction.

Q. Please explain the general process of JCP&L's rate design.

A. Four ratemaking steps are incorporated in designing JCP&L's rates:

1. Revenue Requirement – First, the revenue requirement is developed based on Company operating expenses, taxes, depreciation expense and return on rate base. In her direct testimony (Exhibit JC-03), Ms. Carol A. Pittavino presents the distribution system revenue requirement for JCP&L based on a test year from July 1, 2022 to June 30, 2023;
2. COSS – In this step, as detailed in Mr. Tim Lyon's testimony (Exhibit JC-08), JCP&L's distribution revenue requirement is allocated to various rate classes based on cost causation principles;
3. Interclass Revenue Moderation – Next, the impacts some rate classes would experience if rates were designed to collect their entire COSS-allocated revenue requirement are reviewed and considered for moderation consistent with the principles of gradualism; and
4. Intraclass Rate Design – The final step establishes the individual rates that are ultimately used to bill customers. Such rates are designed to collect the revenue

requirement, as moderated (consistent with the principles of gradualism), from customers on a class-by-class basis.

Q. What do you mean by interclass revenue requirement moderation?

A. The primary objective of this step is to moderate the impact that would result from matching allocation of costs among rate classes based solely on the costs caused by each rate class, as determined by the COSS. This is accomplished through adjustments that balance the application of cost causation principles against other concerns and interests important to sound rate design, including reducing significant rate class cross-subsidies and preventing undue customer impact.

Q. Please explain how interclass revenue requirement moderation is implemented.

A. First, the COSS presents the unitized rates of return ("UROR") for each rate class. The UROR of a rate class is the class rate of return divided by the Company's overall average rate of return.

A class UROR greater than 1.0 indicates that the rate class revenue requirement exceeds its cost of service. A class UROR less than 1.0 indicates that the rate class revenue requirement is less than its cost of service. URORs are used as a guide to measure the progress proposed changes in rates will achieve in moving all rate classes toward a UROR of 1.0 or "unity," which is generally accepted as a desirable goal in rate design.

It is also generally recognized, however, that a very rapid movement toward unity can produce undesirable customer rate impacts. The Board has long held that progress toward unity should be tempered with gradualism to mitigate the impact of rate changes on customers.

Q. What is gradualism?

A. Gradualism is a precept of utility ratemaking that refers to the process of moving to unity over time (*i.e.*, over the course of multiple base rate cases). Gradualism is a consistent consideration in establishing rates for all rate classes. If the movement toward unity would result in subjecting one or more rate classes to an unreasonable customer impact in a particular base rate case, then the principle of gradualism would call for subordinating the goal of achieving unity to the goal of moderating customer impact, even though doing so would cause some classes to generate revenues in excess of their particular COSS-determined class revenue requirement. Where gradualism is an appropriate consideration for a particular rate class, the movement toward unity for that rate class may be done incrementally and spread over time to reduce the risk of rate shock.

Q. What do you mean by intraclass rate design?

A. The COSS provides classified costs (*e.g.*, customer-related or demand-related) and allocates them to each rate class, which facilitates the development of a series of specific corresponding individual rate elements (*i.e.*, customer, demand and energy charges). However, consideration of customer impact, revenue stability, ease of application and understanding, as well as other practical concerns may temper the extent to which these individual rate elements (*i.e.*, customer, demand, and energy charges) are used to reflect the respective costs of service for each cost classification. For example, there are no demand charges for customer classes that do not have demand metering and, therefore, for those customers, both demand and energy costs are recovered with a per-kWh charge.

Once the amount of classified revenue each rate element should produce has been determined based on the COSS, charges for each rate element must be established based

on the applicable billing determinants (*i.e.*, the calculation of anticipated billing demand and energy consumed) so that the rates will produce the target level of revenue.

My general approach to the intraclass rate design step is guided by the following principles:

(i) Individual rates should reflect the associated unit cost of service, so that proposed revenues, derived with rates applied with billing determinants, should move towards full cost basis (*i.e.*, unity), as provided by the COSS;

(ii) The rates by class should increase on a percentage basis to meet the Company's overall rate increase in a measured way with equitable recovery from amongst other classes for any shortfall within each rate class;

(iii) The proposed change in individual rates should ensure reasonable customer impacts.

Q. Please explain the results of the COSS in this filing as it relates to interclass rate design.

A. As mentioned above, the COSS is explained and discussed in the direct testimony of Mr. Tim Lyons (Exhibit JC-8).

Schedule YP-2 summarizes the distribution revenue requirement changes and classified revenue requirements by rate class that have been excerpted from the COSS.

As indicated in Schedule YP-2, the overall proposed increase on the base distribution revenue requirement is $184.95 million, or a 28.8% increase.

While no class will experience a decrease, Service classifications RS and RT (including RGT) will increase by the same percentage (28.8%) as the Company's overall distribution increase. The Service Classification GS, GST, GP – General Service Primary

and GT – General Service Transmission (including special provision d) will increase uniformly by the same percentage (29.8%), consisting of the percentage of the Company's overall distribution increase plus a percentage to proportionally offset the shortfall created by the Lighting class increase, which is 14.4%, or half the percentage of the Company's overall distribution increase.

The proposed revenue requirement changes move all rate classes closer to an UROR of 1, while balancing the overall customer impact as provided in Schedule YP-5.

Q. Please describe the rate structure resulting from the rate design used to establish the rates set forth in the current tariff.

A. The rates set forth in the Company's current tariff (Part III) were approved by the BPU in the Company's 2020 Base Rate Filing proceeding and reflect the Board's decisions regarding rate structure and rate design made in that case. While the Company proposes changes to various rates, the changes reflected in the Company's proposed rates do not change the underlying rate structure and principles applied in rate design, as approved in the 2020 Base Rate Filing.

Consistent with the changes in class revenue requirements set forth in Schedule YP-2, the Company is proposing to increase the rates for each Service Classification as follows:

Residential Customers: For customers served under Service Classifications RS, the Company is proposing to increase the monthly customer charges and the monthly supplemental charges for water heating toward full recovery of the classified customer revenue requirement from COSS. While the COSS study justifies the customer cost to be $6.89 ($7.35 including sales and use tax ("SUT"),

the Company is proposing $5.25 ($5.60 including SUT), an increase of $2.20 ($2.35 including SUT) to recover 76% of the cost. Currently, the average customer charge among other New Jersey EDCs is $5.65, including SUT. The proposed distribution charges, which are expressed on a per-kWh basis, were calculated by increasing the current charges by an equal percentage, such that the sum of (a) the revenue that would be produced by such proposed distribution charges and (b) the revenue that would be produced by the proposed customer charges equals (c) the target revenue.

For customers served under Service Classifications RT and RGT, the Company proposes to increase both the customer charge and distribution charges uniformly at the overall class increase.

Commercial and Industrial Customers. For customers served under Service Classification GS, the Company proposes to increase the customer charge, demand charge (which is expressed on per kW basis), and the distribution charge (which is expressed on a per kWh basis) by the same percentage (29.8%) as the overall class level increase.

For customers served under Service Classifications GST, GP and GT, the Company proposes to increase the customer charge and demand charge to recover the overall class level revenue increase. The distribution charge would be increased at a certain percentage so that the sum of the resulting (a) distribution revenue, (b) demand revenue and (c) customer charges proposed would equal (d) the target class level revenue requirement. To avoid unreasonable customer impacts resulting from the gradual movement of distribution charges into the customer and demand charge, it is necessary to temper the customer and demand charge increases as follows: the

customer charge will be increased by the same percentage as the overall class level increase; and the demand charge will be increased by an additional 7.5% on average above the overall class level increase. This equates to an approximate 4.5% revenue increase recovered through the distribution charge.

Lighting Customers. For customers served under Service Classifications OL (Outdoor Lighting Service), SVL (Sodium Vapor Street Lighting Service), MVL (Mercury Vapor Street Lighting – Restricted), ISL (Incandescent Street Lighting – Restricted) and LED (LED Street Lighting Service), all distribution charges (including fixture, miscellaneous and kWh charges) under current rates are proposed for increase by an equal percentage (*i.e.*, Lighting total percent increase in distribution revenue) to produce the target level of revenues for these tariff service classifications.

Q. Is the Company proposing any additional interclass and intraclass rate design adjustments?

A. The Company does not plan to propose additional adjustments. However, the Company recognizes that, over the course of any rate proceeding, other parties may propose adjustments to the interclass or intraclass determinations and proposals that differ from those originally made by the Company. Any such proposals would necessarily impact other aspects of the rate structure resulting from the rate design, or the rate design itself. Therefore, the Company reserves the right to respond, if, and as, necessary, to any such proposed modifications to identify other changes that might be required to accommodate any such proposals.

Q. Did you perform a proof of revenues analysis?

A. Yes, I did. Schedule YP-3 demonstrates, in summary form, the accounting for the total requested revenue requirement based upon the COSS. Schedule YP-4 sets forth: (1) the normalized billing determinants (*i.e.*, expected billing demand and energy consumption) in the test year used to develop all proposed distribution rates; (2) the test year revenue based on present rates; (3) the test year revenue based on proposed rates; and (4) the percentage increase resulting from the proposed rates.

Q. Please discuss the customer impact of the proposed changes in distribution rates.

A. The results are contained in Schedule YP-5. In performing this analysis, the first step was to identify all rate components that would be included in all customers' bills, as of March 1, 2023. The rate components include: distribution charges (including customer charges), societal benefits charges, non-utility generation charges, the RGGI recovery charge, the Zero Emission Certificate Recovery Charge, Tax Act Adjustment and JCP&L Lost Revenue Adjustment Mechanism Charge as set forth in the current tariff. Additionally, customers that do not select an alternate generation supplier will have Basic Generation Service ("BGS") charges (including transmission charges) as a component on their bills.

The customer impact analysis model incorporates all rate components by tariff rate class. In performing the customer impact analysis, total revenues billed for the 12 months prior to March 1, 2023 were compared to the total revenues that would be produced by the distribution tariff rates proposed in this proceeding to become effective January 1, 2024, yielding the results of the proposed changes in both total revenue dollars and in percentages by tariff rate class. Because the SUT is included in customer bills, the customer impact analysis also includes SUT to show the results from the customers' perspective.

Q. Does this conclude your direct testimony?

A. Yes, it does.

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU NO. 13 ELECTRIC ORIGINAL TITLE SHEET

TARIFF for SERVICE

Part I

General Information

Part II

Standard Terms and Conditions

Issued: October 30, 2020 Effective: December 1, 2020

Filed pursuant to Order of Board of Public Utilities
Docket Nos. ER20020146 and PUC 04343-2020N dated October 28, 2020

Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 13 ELECTRIC - PART I Original Sheet No. 1

PART I
GENERAL INFORMATION
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JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 13 ELECTRIC - PART I Original Sheet No. 2

General Information

A - Service Tariff: This tariff for Service ("Tariff") of Jersey Central Power & Light Company, ("Company"), is filed with the Board of Public Utilities of New Jersey ("BPU") pursuant to NJAC 14:3-1.3. The Standard Terms and Conditions set forth in Part II of this Tariff state the conditions under which Service is rendered, and govern the Company's provision of Full Service, Delivery Service and/or other Services to the extent applicable. The Service Classifications and Riders contained in Part III of this Tariff state the basis for computing the charges to Customers for Service. Except where specifically modified by written contract, all applicable provisions of this Tariff constitute, or are a part of, each service contract, express or implied, and both the Customer and the Company shall be bound thereby.

B - Revision of Tariff: The Company may at any time, and in any manner permitted by law and the applicable rules and regulations of the BPU, supplement, terminate, change, or modify this Tariff or any part thereof.

C - Exchange of Information: The Company will, at the Customer's request, explain the provisions of its Tariff and inform the Customer as to the conditions under which Service can be obtained from the Company's system. It is the responsibility of the Customer or his agent, before making his initial electrical installation or planning material changes in an existing installation, to obtain from the Company information regarding the characteristics of available Service, its designation of the point of attachment of the service connection and meter location, and such other information as may be necessary to assure that the Customer's installation will be compatible with the facilities and Service the Company will supply.

D - Statements by Agents: No representative of the Company has authority to modify any provision contained in this Tariff or bind the Company by any promise or representation contrary thereto.

E - Agreements and Contracts: Standard agreements to provide Service shall be in accordance with Parts II and III of this Tariff. As a condition for establishing, continuing, or resuming the provision of Service in a situation where the Company incurs or will incur greater than normal investment cost or operating expense in order to meet the Customer's special or unusual Service requirements, or to protect the Company's system from undue disturbance of voltage regulation or other adverse effects, and in order to avoid undue discrimination, the Company may require an agreement for a longer term than specified in the applicable Service Classification, may require a contribution in aid of construction and may establish such minimum charges and facilities charges as may be equitable under the circumstances.

General Information

F – Definitions: The following terms are herein defined for general reference to assist in their application in Parts II and III of this Tariff.

(1) Alternative Electric Supplier: Any person, corporation or other entity, other than the Company, that has applied for and received an electric power supplier license from the BPU.

(2) Applicant: Any person, corporation or other entity that (a) desires to receive from the Company electric generation or any other Service provided for in this Tariff, (b) complies completely with all Company requirements for obtaining electric generation or any other Service provided for in this Tariff, (c) has filed and is awaiting Company approval of its application for Service, and (d) is not yet actually receiving from the Company any Service provided for in this Tariff. An Applicant shall become a Customer for purposes of this Tariff only after it actually starts receiving the applicable Service from the Company under this Tariff.

(3) Beneficiary: The person, corporation or the entity financially benefiting from the service.

(4) Billing Month: Generally, that calendar month in which the majority of the Company's meters are read for the purpose of establishing the electric service usage of Customers for their prior 26 to 35 day period.

(5) Connected Load: The sum of the input ratings of all electric-using devices located on the Customer's premises and which are or can be, by the insertion of a fuse, closing of a switch, or any similar method, connected simultaneously to the Company's Service. Although the manufacturer's nameplate rating may be used to determine the input rating of any particular device, the Company may instead determine the input rating of any device by test.

(6) Contract Capacity: That electrical capacity which the Customer specifies is needed to supply the Customer's requirements for Service and which the Company agrees to furnish through either Full Service or Delivery Service.

(7) Contract Location: Each metering point shall be considered a contract location and shall be metered and billed under a separate service contract. In cases where unmetered service is provided, the Point of Delivery shall be considered a contract location.

(8) Customer: Any person, partnership, association, corporation, or agency of municipal, county, state, or federal government receiving any Service rendered by the Company under this Tariff at a Contract Location. The term "Customer" shall also include Applicant when, in the Company's opinion, the specific provision of this Tariff was intended to be so inclusive. Any customer receiving Delivery Service shall simultaneously be a customer of an Alternative Electric Supplier.

(9) Delivery Service: The provision of electric distribution and other services by the Company to Customers under this Tariff who purchase their electric generation service from Alternative Electric Suppliers.

General Information

(10) End User: A person who receives, uses or consumes service. An end user may or may not be a customer as defined herein.

(11) Full Service: The provision of electric distribution and other services by the Company to Customers under this Tariff who purchase their electric generation service from the Company.

(12) Line Extension: This term applies to those overhead or underground facilities for the distribution or transmission of electrical energy to serve new Customers or the enlarged load of existing Customers which are constructed by the Company as a specific project (a) on a public highway and/or (b) on a right-of-way over private or public land to serve one or more Customers. Such an extension may be an addition to and/or upgrade of existing facilities or a new installation of facilities. A line extension originates at the pole or point at which it is connected to the existing facilities or where such upgraded facilities are required and it extends to and includes (a) the most remote pole or point from which a "Service Drop" or "Underground Service Connection" is installed, or (b) to the point at which a "Service Lateral" originates.

(13) Point of Delivery: The point at which the Customer receives Service and from which point inward, with respect to the premises served, the Customer assumes responsibility and liability for the presence or use of electricity in the Customer's installation.

(14) Residence: A structure or portion of a structure intended for use as sleeping quarters by a person or persons, and containing cooking and sanitary facilities.

Auxiliary Residential Purposes: Electric loads used on the premises in conjunction with the operation, use, and maintenance of an individual Residence. Such loads may include yard lighting, swimming pool pumps and heaters, saunas, driveway heaters, household workshops, yard maintenance equipment, and garages or outbuildings when used in conjunction with the operation, use, or maintenance of the Residence.

Multiple Residential Structure: A structure containing more than one Residence and having no direct access between them except from the outside or a common hall.

Group Residential Structure: A structure containing a Residence and five or more sleeping quarters intended for rental purposes, and not qualifying as a Multiple Residential Structure.

Individual Residential Structure: A structure containing a Residence and not qualifying as a Multiple Residential Structure or a Group Residential Structure.

Incidental Non-Residential Purposes: Non-Residential loads totaling 10 kW or less and which are less than 30% of the Residential and/or Auxiliary Residential connected load it is metered with.

Non-Residential Purposes: Electric loads which do not qualify under "residential purposes" or "auxiliary residential purposes." Such loads shall include but are not limited to, ceramic kilns, electric welders, greenhouses, and loads used for farming, business, professional, avocation, or animal housing purposes.

General Information

(15) Service: The term "Service" (generally upper case), as used in this Tariff, references any electricity, or access to electricity, that is provided by the Company pursuant to this Tariff, or anything related to the provision of electricity, or access to electricity, provided or rendered by the Company pursuant to this Tariff. Note that the word "service" (generally lower case) is also used from time to time in this Tariff to reference services rendered by entities other than the Company (such as Alternative Electric Suppliers). The distinction between the Company's Services and other entities' services is apparent from the context, and the use of upper and lower case is intended to aid the reader in taking note of the distinction.

(16) Service Connection: The conductors and equipment for delivering Service from the Company's supply system to the service entrance on the customer's premises. If overhead, such Service Connection, also known as a "Service Drop," terminates at a fixture or fixtures installed on the Customer's building or structure at a location designated by the Company which will provide the required clearance of the Service Drop conductors with respect to intervening objects or surfaces. An underground Service Connection is the equivalent of the overhead Service Connection and terminates either at the Customer's over-current protective device on the inside of the first foundation wall adjacent to the street on which the Company's mains are situated or at the meter base installed as part of the “Service Entrance”. If the Company's primary or transmission delivery system is directly connected to the Customer's facilities, such as through transformation or circuit breaking facilities which constitute the service connection, the Point of Delivery shall be the point of connection between the Customer's facilities and the Company's facilities, which is usually identified in a written contract that provides for such direct connection. In other instances, the Point of Delivery is as specified in the definition of "Service Entrance."

(17) Service Drop: A Company-owned overhead Service Connection.

(18) Service Entrance or Entrance Facilities: In general, the conductors or accessory equipment by which electricity is carried from the Service Connection to the supply side of the devices protecting the Customer's circuits. If the Service Entrance is owned by the Customer, it is referred to as "Customer's Entrance Facilities" and the Point of Delivery is the junction of the Service Connection conductors with the Service Entrance. If the Service Entrance is owned by the Company, it is referred to as "Company's Service Entrance" and the Point of Delivery is at the supply side of the devices protecting the Customer's circuits. The metering devices are not included as part of the Service Entrance**.**

(19) Service Lateral: The electrical facilities constituting a branch from the Company's system, installed on private property to serve a single Customer. A Service Lateral may be either overhead or underground. If overhead, the Service Lateral originates at the pole or point at which connection is made to the existing system or line extension and extends to the pole or other aerial support where the Service Drop originates. When a secondary underground Service Lateral is owned, installed, and maintained by the Customer, it shall consist of the specified conduit and cable between its connection with the Company's system and the premises where the Service is to be used. A non-secondary overhead or underground Service Lateral may provide a circuit connection to Company-owned or Customer-owned transformers set in a vault or on a pad on the Customer's premises.

General Information

(20) Standby Service: Service that the Customer may receive or may request that the Company furnish in the event of a breakdown, shutdown, failure, or other impairment of a generator on the Customer's premises, from which the Customer normally receives all or a portion of his energy requirements.

(21) Summary Billing: A Service whereby the Company will add together the charges for multiple Full Service accounts maintained by one Customer and provide the Customer with a single bill.

(22) Tampering: Tampering shall mean connecting or causing to be connected by wire or any other device with the wires, cables or conductors of the Company, or connecting, disconnecting or shunting the meters, cables, conductors or other equipment of the Company, without the Company's permission. (See Part II, Sections 5.03, 6.04, 6.05, 6.06, 6.07, 6.08 and 7.03) (See N.J.S.A. 2C:20-8)

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 13 ELECTRIC - PART I Original Sheet No. 7

General Information

G - Municipalities Served: The following list designates those municipalities in which the Company serves the public through its distribution facilities.

BURLINGTON COUNTY

Chesterfield Twp.
New Hanover Twp.
North Hanover Twp.
Pemberton Boro
Pemberton Twp.
Southhampton Twp.
Springfield Twp.
Woodland Twp.
Wrightstown Boro

ESSEX COUNTY
Livingston Twp.
Maplewood Twp.
Millburn Twp.

HUNTERDON COUNTY
Alexandria Twp.
Bethlehem Twp.
Bloomsbury Boro
Califon Boro
Clinton, Town of
Clinton Twp.
Delaware Twp.
East Amwell Twp.
Flemington Boro
Franklin Twp.
Frenchtown Boro
Glen Gardner Boro
Hampton Boro
High Bridge Boro
Holland Twp.
Kingwood Twp.
Lambertville, City of
Lebanon Boro
Lebanon Twp.
Milford Boro
Raritan Twp.
Readington Twp.
Stockton Boro
Tewksbury Twp.
Union Twp.
West Amwell Twp.

MERCER COUNTY
East Windsor Twp.
Hightstown Boro
Hopewell Twp.
Washington Twp.
West Windsor Twp.

MIDDLESEX COUNTY
Cranbury Twp.
East Brunswick Twp.
Helmetta Boro
Jamesburg Boro
Monroe Twp.
Old Bridge Twp.
Sayreville Boro
South Amboy, City of
South Brunswick Twp.
Spotswood Boro

MONMOUTH COUNTY
Aberdeen Twp.
Allenhurst Boro
Asbury Park, City of
Atlantic Highlands Boro
Avon-by-the Sea Boro
Belmar Boro
Bradley Beach Boro
Brielle Boro
Colts Neck Twp.
Deal Boro
Eatontown Boro
Englishtown Boro
Fair Haven Boro
Farmingdale Boro
Freehold Boro
Freehold Twp.
Hazlet Twp.
Highlands Boro
Holmdel Twp.
Howell Twp.
Interlaken Boro
Keansburg Boro
Keyport Boro

MONMOUTH COUNTY (Continued)
Lake Como Boro
Little Silver Boro
Loch Arbour, Village of
Long Branch, City of
Manalapan Twp.
Manasquan Boro
Marlboro Twp.
Matawan Boro
Middletown Twp.
Millstone Twp.
Monmouth Beach Boro
Neptune City Boro
Neptune Twp.
Oceanport Boro
Ocean Twp.
Red Bank Boro
Roosevelt Boro
Rumson Boro
Sea Bright Boro
Sea Girt Boro
Shrewsbury Boro
Shrewsbury Twp.
Spring Lake Boro
Spring Lake Heights Boro
Tinton Falls Boro
Union Beach Boro
Upper Freehold Twp.
Wall Twp.
West Long Branch Boro

MORRIS COUNTY
Boonton, Town of
Boonton Twp.
Butler Boro
Chatham Boro
Chatham Twp.
Chester Boro
Chester Twp.
Denville Twp.
Dover, Town of
East Hanover Twp.

General Information

MORRIS COUNTY (Continued)
Florham Park Boro
Hanover Twp.
Harding Twp.
Jefferson Twp.
Kinnelon Boro
Lincoln Park Boro
Long Hill Twp.
Madison Boro
Mendham Boro
Mendham Twp.
Mine Hill Twp.
Montville Twp.
Morris Twp.
Morristown, Town of
Morris Plans Boro
Mountain Lakes Boro
Mt. Arlington Boro
Mt. Olive Twp.
Netcong Boro
Parsippany-Troy Hills Twp.
Pequannock Twp.
Randolph Twp.
Riverdale Boro
Rockaway Boro
Rockaway Twp
Roxbury Twp.
Victory Gardens Boro
Washington Twp.
Wharton Boro

OCEAN COUNTY
Barnegat Twp.
Bay Head Boro
Beachwood Boro
Berkeley Twp.
Brick Twp.
Dover Twp.
Island Heights Boro
Jackson Twp.
Lacey Twp.
Lakehurst Boro
Lakewood Twp.
Lavallette Boro
Manchester Twp.

OCEAN COUNTY (Continued)
Mantoloking Boro
Ocean Twp.
Ocean Gate Boro
Pine Beach Boro
Plumsted Twp.
Point Pleasant Boro
Point Pleasant Beach Boro
Seaside Heights Boro
Seaside Park Boro
South Toms River

PASSAIC COUNTY
Bloomingdale Boro
Pompton Lakes Boro
Ringwood Boro
Wanaque Boro
Wayne Twp.
West Milford Twp.

SOMERSET COUNTY
Bedminster Twp.
Bernards Twp.
Bernardsville Boro
Branchburg Twp.
Bridgewater Twp.
Far Hills Boro
Green Brook Twp.
Hillsborough Twp.
Peapack-Gladstone Boro
Warren Twp.
Watchung Boro

SUSSEX COUNTY
Andover Boro
Andover Twp.
Branchville Boro
Byram Twp.
Frankford Twp.
Franklin Boro
Fredon Twp.
Green Twp.
Hamburg Boro
Hampton Twp.
Hardyston Twp.

SUSSEX COUNTY (Continued)
Hopatcong Boro
Lafayette Twp.
Montague Twp.
Newton, Town of
Ogdensburg Boro
Sandyston Twp.
Sparta Twp.
Stanhope Boro
Stillwater Twp.
Sussex Boro
Vernon Twp.
Wallpack Twp.
Wantage Twp.

UNION COUNTY
Berkeley Heights Twp.
Mountainside Boro
New Providence Boro
Springfield Twp.
Summit, City of

WARREN COUNTY
Allamuchy Twp.
Alpha Boro
Belvidere, Town of
Blairstown Twp.
Franklin Twp.
Frelinghuysen Twp.
Greenwich Twp.
Hackettstown, Town of
Hardwick Twp.
Harmony Twp.
Hope Twp.
Independence Twp.
Knowlton Twp.
Liberty Twp.
Lopatcong Twp.
Mansfield Twp.
Oxford Twp.
Phillipsburg, Town of
Pohatcong Twp.
Washington Boro
Washington Twp.
White Twp

JERSEY CENTRAL POWER & LIGHT COMPANY

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General Information

H – Customer Contact Information:

Emergency / Power Outage Reporting	1-888-544-4877
General Customer Service	1-800-662-3115
Payment Options	1-800-962-0383
Telecommunications Relay Service (TRS) for the Hearing Impaired	711

Morristown General Office
300 Madison Avenue, Morristown, NJ 07962-1911 — 1-973-401-8200

Customer Billing Questions or Complaints
JCP&L 76 S. Main Street, A-RPC, Akron, OH 44308-1890

Website:
http://www.firstenergycorp.com

Northern Region Business Offices:

Morristown	300 Madison Avenue, Morristown, NJ 07962
Hopatcong	175 Center Street, Landing, NJ 07850
Phillipsburg	400 Lincoln Street, Phillipsburg, NJ 08865

Central Region Business Offices:

Allenhurst	300 Main Street, Allenhurst, NJ 07711
Toms River	25 Adafre Avenue, Toms River, NJ 08753
Old Bridge	1345 Englishtown Road, Old Bridge, NJ 08857

ALL TELEPHONE INQUIRIES PLEASE USE CUSTOMER CONTACT INFORMATION ABOVE

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 13 ELECTRIC - PART II Original Sheet No. 1

PART II
STANDARD TERMS AND CONDITIONS
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Filed pursuant to Order of Board of Public Utilities
Docket Nos. ER20020146 and PUC 04343-2020N dated October 28, 2020

Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

PART II
STANDARD TERMS AND CONDITIONS
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JERSEY CENTRAL POWER & LIGHT COMPANY

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PART II
STANDARD TERMS AND CONDITIONS
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JERSEY CENTRAL POWER & LIGHT COMPANY

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PART II
STANDARD TERMS AND CONDITIONS – TABLE OF CONTENTS

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 13 ELECTRIC - PART II Original Sheet No. 5

Section 1 - Service Availability

NOTE: Unless specifically stated otherwise, Part II of the Company's Tariff (Standard Terms and Conditions) generally describes the responsibilities of and obligations between Customers and the Company. Specific standards governing the relationship between Customers and the Alternative Electric Supplier and between the Alternative Electric Supplier and the Company have been set forth by the BPU and are noted with references to such BPU Order(s) where applicable to the Company's Tariff.

1.01 Characteristics of Service: The standard electrical supply service provided by the Company is alternating current with a nominal frequency of 60 hertz. Not all types of service listed below are available at all locations, and service voltages other than secondary may be specified by the Company under special conditions such as may relate to the location, size, or type of load. The Company may specify the voltage, phase, and minimum and maximum load that it will supply at any particular voltage. The Company will furnish transformation facilities for secondary service up to a maximum of 300 KVA pole-mounted or 2500 KVA pad-mounted per contract location. Contract locations requiring in excess of these limits may, at the Company's discretion, be provided untransformed service, in which case the customer shall install, own, operate, and maintain the necessary transformation and associated facilities, except metering, in accordance with Company service requirements. Subject to the foregoing limitations, the types of service available with their nominal voltages are:

Secondary Service:

Single-phase	2 wire	120 volts
Single-phase	3 wire	120/240 volts
Single-phase	3 wire	120/208Y volts
Three-phase	4 wire	120/240 volts
Three-phase	4 wire	120/208Y volts
Three-phase	4 wire	277/480Y volts

Primary Service:

Single-phase	2 wire	2400 volts
Single-phase	2 wire	4800 volts
Three-phase	3 wire	2400 volts
Three-phase	4 wire	2400/4160Y volts
Three-phase	3 wire	4800 volts
Single-phase	2 wire	7200 volts
Three-phase	4 wire	7200/12470Y volts
Three-phase	4 wire	7620/13200Y volts
Three-phase	3 wire	13200 volts
Three-phase	4 wire	19900/34500Y volts

Transmission Service:

Three-phase	3 wire	34500 volts
Three-phase	3 wire	115000 volts
Three-phase	3 wire	230000 volts

The Company must always be consulted regarding the type of Service to be supplied.

Section 1 - Service Availability

1.02 Single Point of Delivery: The Company will designate the Point of Delivery and meter location. Service under a particular Service Classification will be supplied to each building or contract location through only one set of Service Connection conductors and metering equipment, except where the Service Classification may require otherwise or where, for economy, engineering, or operating considerations or by reason of applicable codes or governmental regulations, the installation of more than one Service Connection is necessary. Such duplicate or auxiliary delivery sources shall be furnished by separate contract under the applicable Service Classification and special provision. Service so delivered shall be used only at the premises where the Service is connected.

1.03 Compliance with Service Classification: Service provided by the Company shall not be used for purposes other than those recognized within the applicable Service Classification or pursuant to any special provisions under which the Customer is being served. When the use of Service is not in compliance with the terms of any such special provisions or Service Classification, the Customer shall be transferred to and billed under the applicable schedule of charges or disconnected from Service as provided for in this Tariff. (Also see 4.07 and 7.03)

1.04 Residential Purposes: Electric loads required for the operation and use of an individual residence. Such loads may include that for lighting, cooking, appliance operation and water pumping as well as space and water heating. Also see Part I, Section F, Definition (14) for definitions of residence and residential structures.

1.05 Resale of Service: Customers shall not resell Service for profit. Customers who distribute electric energy from their Point of Delivery to other occupants of the premises may install metering at their own expense to determine the energy usage and amount owed to the Customer for energy usage at those sub-locations. Where the use of the premises is basically residential, such meters of sub-locations will be permitted only for those buildings constructed prior to January 1, 1978, which are co-operative or condominium residential apartment buildings, or are publicly financed or government-owned. A reasonable administrative charge may be made by the customer to the other occupants for determining and billing them for their energy usage.

For multiple occupancy residential buildings constructed after January 1, 1978, separate metering owned and installed by the Company is required for each dwelling unit as provided in the New Jersey Uniform Construction Code.

1.06 Unusual Conditions: The Company, at its sole discretion, may discontinue or refuse to provide Service to loads which might adversely affect the normal operation of facilities of the Company or its customers. Service to such loads may be provided where the customer, at its own expense, has installed corrective equipment in accordance with general or individual non-discriminatory requirements and specifications of the Company. The Company may also discontinue or refuse to supply service to loads so installed or connected that an unbalance greater than 10% exists between the phases of the customer's service. Customers should contact the Company prior to purchasing or connecting motors or other equipment to determine the maximum allowable inrush current and/or to determine the suitability of the equipment to the Company's system. (Also see Section 4.05)

Section 1 - Service Availability

1.07 Curtailable Load Limitation: The curtailable load of all customers provided for under this Tariff shall not exceed 2.5% of the Company's annual peak load in the preceding calendar year.

1.08 Multiple Services for Transmission Customers: Service will be supplied to several delivery points at the same or different voltages as mutually agreed, providing that such delivery points are connected together by interconnecting lines and transformation facilities which are either owned, operated, and maintained by the Customer, or owned, operated, and maintained wholly or in part by the Company, upon payment to the Company of a monthly charge of 1.5% of the original cost of such facilities as are provided by the Company. Such interconnection by mutual agreement may be operated either normally closed or open, and in either case shall be changed only by or at the direction of the Company for emergency and maintenance purposes. Where such interconnection is available, each separate delivery point will be individually metered, and billing shall be based on the sum of the highest coincident demands and the sum of the kilowatt-hours registered at the individual metering points after correcting for transformation losses. Such meter registrations are not measured at transmission voltage.

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Section 2 - Service Applications, Agreements & Contracts

2.01 Application and Connection: All Applicants seeking to receive any type of Service from the Company under this Tariff shall contact the Company and specifically request the type and nature of Service. An Applicant for any Service under this Tariff may be required to sign an application or contract for Service. However, the Company may, in its sole discretion, accept an oral application from an Applicant. Applicants for Service shall supply to the Company all information deemed necessary by the Company from time to time to provide such Service including, but not limited to, connected electrical load, types of electrical equipment, and the mode of operation of the electrical equipment.

Upon the receipt of Service, the Applicant shall become a Customer of the Company. At any time, the Customer shall inform the Company in advance of any proposed additions to (or decreases in) the Customer's Connected Load.

Whenever Service is initiated to any Customer in any particular location or resumed after discontinuance at the request of the Customer, a Service Charge shall be made as specified in Part III of the Tariff.

If a Delivery Service Customer, for whatever reason, receives electric supply from the Company, that Customer will be considered a Full Service Customer beginning with the date on which such electric supply is furnished to the Customer by the Company.

2.02 Forms and Information: The Company will, upon request, explain the provisions of its Tariff and the conditions under which Service can be obtained. It is the responsibility of any Applicant for new or modified Service to obtain from the Company information regarding the characteristics of available Service, the Point of Delivery of Service, its designation of the point of Service Connection and meter location, and such other information as may be necessary to assure that the Customer's installation will be compatible with the facilities and Service the Company will provide before making the initial electrical installation or planning material changes in an existing installation. The Company will furnish such application and contract forms as may be appropriate. The Applicant shall supply all of the information called for by such forms.

2.03 Selection of Service Classification: The Company will assist in the selection of the Customer’s applicable Service Classification. In furnishing such assistance, the Company assumes no responsibility whatsoever. If for any reason the Customer fails to make a selection, the Company will assign a Service Classification based upon facts at hand at the time Service is furnished. A Customer may, upon written notice to the Company, elect to change and to receive Service under any other applicable Service Classification or special provision. The Company will bill the Customer under the Service Classification so selected for Service delivered from the date of the next scheduled meter reading, but the Company may refuse to permit any further change in selection of Service Classification or special provision during the next twelve months, except as may be permissible under Section 1.03.

Section 2 - Service Applications, Agreements & Contracts

2.04 Modification or Rejection of Application: The Company may place limitations on the amount and character of Service it will provide, or may refuse to provide Service to new Customers or to any additional load of existing Customers, if it is not able to obtain, install, operate, or maintain the necessary equipment and facilities to provide such Service. The Company, after proper notice, may refuse to initiate Service or may discontinue Service to an Applicant, or to a Customer who is a member of the household or is a business associate, or landlord, of a former Customer then indebted to the Company for Services provided by the Company at any location, if the Company has reason to believe that substantially the same household or business will or does occupy the premises to be or being served and that the purpose of the present or earlier application is or was to circumvent payment of such indebtedness. However, if the household or business is not the same, the Company can only transfer the outstanding balance of amounts owed to the Company for Services provided by the Company to the former Customer of record for Service rendered at the prior location.

2.05 Contract by Use of Service: Receipt and use of Service provided by the Company shall render the recipient a Customer of the Company. If such Service is provided and accepted, or used in the absence of a written agreement for Service approved by the Company, such recipient shall be deemed to have entered into an agreement with the Company, the furnishing, receipt, and use of such Service shall be subject to the provisions of this Tariff and such Customer shall be charged for such Service in accordance with the applicable Service Classification.

2.06 Term of Contract: The term of contract is stated in the applicable Service Classification or in a written agreement. Customers shall give notice of intention to terminate Service to a responsible agent of the Company in accordance with the requirements of any applicable Service Classification or written agreement and, in any event, reasonably in advance of intended Service termination or change in Customer identity. Termination of Service on notice from the Customer, or for any other reason permitted by this Tariff prior to the completion of a contract for Service, shall not relieve the Customer from payment of the charges for the unexpired portion of the term and the same shall be due and payable immediately.

2.07 Unauthorized Use: Unauthorized connection to the Company's facilities, or the use of Service (either metered or unmetered) without Company authorization may be terminated by the Company without notice. The use of Service without notice to the Company shall render the End User or Beneficiary liable for any amount due for Service provided to the premises since the last reading of the meter as shown by the Company's records or for unmetered Service used since the last billing.

2.08 Statements by Agents: No representative of the Company has authority to modify any provision contained in this Tariff or bind the Company by any promise or representation contrary thereto, and the Company shall not be bound thereby.

2.09 Special Agreements: As a condition for establishing, continuing, or resuming the provision of Service in a situation where the Company incurs or will incur greater than normal investment cost or operating expense in order to meet the Customer's special or unusual Service requirements or to protect the Company's system from undue disturbance of voltage regulation or other adverse effects and in order to avoid undue discrimination, the Company may require an agreement for a longer term than specified in the applicable Service Classification, may require a contribution in aid of construction, and may establish such minimum charges and facilities charges as may be equitable under the circumstances. (Also see Section 4.05)

Section 3 - Billings, Payments, Credit Deposits & Metering

3.01 Measurement of Electricity Consumption: The Service provided to the Customer will be measured separately for each Point of Delivery by metering. Bills will be based upon the registration of such metering equipment except as may be otherwise provided in this Tariff. Such registration shall be conclusive as measuring the quantity of Service received by the Customer except when the metering equipment fails to register or is determined to be registering outside the limits of accuracy prescribed by the BPU. In some instances the Company may, at its sole discretion, allow for unmetered Service. (Also see Sections 3.15 and 3.16)

3.02 Separate Billing for Each Installation: Service provided through each meter shall be billed separately in accordance with this Tariff. Conjunctive billing, which is the combination of the quantities of energy, demand, or other billing elements of two or more meters or Services into respective single quantities for the purpose of billing as if the bill were for a single meter or Service, will not be permitted except where more than one meter has been installed for Company operating reasons. (Also see Sections 1.02 and 3.15)

3.03 Meter Reading and Billing Period: Unless otherwise specified, the charges for Service are stated on a monthly basis. Meters are read on a regular schedule, as nearly as practicable every 30 days. The term "month" as used in this Tariff, generally means the period between any two consecutive regularly scheduled meter readings. The term "billing period" usually refers to the interval of time elapsing between two consecutive meter readings, but it may mean other time intervals, either actual or estimated, taken or made for the purpose of computing the amount due to the Company from the Customer. Bills to Customers will normally be rendered monthly, but the Company may, in its sole discretion, read meters and render bills generally, or to limited groups of Customers, on other than a monthly basis for either experimental purposes or as a regular procedure, after giving reasonable notice to the affected Customers and to the BPU. In such event the monthly charges stated in the applicable service classification shall be prorated to conform to the new billing period. (See NJAC 14:3-7.4)

3.04 Prorating of Monthly Charges: All bills for periods other than 26 to 35 days inclusive will be computed by prorating the monthly charges provided in the applicable service classifications on the basis of the relationship between the number of days in the billing period and 30 days.

3.05 Estimated Bills: Where the Company has not obtained a reading of the meter it may submit a bill for the minimum charge, or estimate the amount of Service provided and submit an estimated bill. Such bill is subject to adjustment on the basis of the actual Service provided as established by the next actual meter reading, or for any unusual circumstances known to have affected the amount of Service provided.

The Company reserves the right to discontinue Service when a meter reading has not been obtained for eight months or more and after written notice is sent to the customer per NJAC 14:3-7.2. The Company will use all reasonable means to obtain a meter reading before discontinuing Service. (Also see Section 7.03 and NJAC 14:3-3A.1)

Section 3 - Billings, Payments, Credit Deposits & Metering

3.06 Billing Adjustments: An adjustment of charges due to the Company for Services provided by the Company will be made if a meter is found to be registering as fast; more than two percent. The adjustment will be made corresponding to the percentage error as found in the meter covering the entire period which the meter registered inaccurately, provided such a period can be determined. If such period cannot be determined, a correction shall be applied to ½ of the total amount of billing affected since the most recent prior meter test. No adjustment shall be made for a period greater than the time during which the customer has received service through the meter in question. Billing adjustments will be in accordance with N.J.A.C. 14:3-4.6 and shall not be for a period of more than six years prior to the time the reason for the adjustment became known to the Company.

3.07 Billing of Charges in Tariff: Unless otherwise designated, the charges set forth in this Tariff shall apply to Service rendered on and after the effective date specified in the applicable Service Classification.

3.08 Payment of Bills: Bills for Service provided by the Company are payable when rendered and are due within fifteen days of the mailing date of the bill or as otherwise prescribed by regulation NJAC 14:3-3A.3. They can be paid at any business office of the Company, to any duly authorized collector or collection agency, by mail, or by electronic funds transfer. If a bill is not paid by the date indicated on the bill, the Company, on not less than ten days written notice, may discontinue service to the Customer after 27 days following rendition of the bill or as otherwise prescribed by regulation. (See NJAC 14:3-3A.3)

Whenever a residential Customer advises the Company that the Customer wishes to discuss a deferred payment agreement because of a present inability to pay a total outstanding bill and/or a security deposit, the Company will make a good faith effort to provide the Customer with a reasonable deferred payment agreement. Either prior to or after the discontinuance of service for non-payment, a residential Customer may be required to pay a down payment of not more than 25% of the total outstanding bill due at the time of the agreement. Deferred payment agreements which extend more than two months must be in writing. The Company is not required to offer or enter into more than one deferred payment agreement in a 12-month period, but the Company may, in its sole discretion, elect to offer more than one such agreement in the same 12-month period. If the Customer defaults on any of the terms of the agreements, the Company may discontinue service after providing the Customer with a notice of discontinuance. (See NJAC 14:3-7.7)

A Customer's failure to receive a bill shall not relieve the Customer of any of the Customer's obligations hereunder.

Where a non-residential Customer requests a deferred payment agreement, the agreement shall be limited to a period of no more than three months, and the Customer may be required to make a partial payment at the time of entering into the deferred payment agreement. The amount of the partial payment shall be no more than one half of the amount past due and owing at that time. The existence of a deferred payment agreement does not relieve the Customer of applicable monthly late payment charges. (See Section 3.19)

3.09 Guarantee of Payment: Where the credit of an Applicant for Service is impaired or not established, or where the credit of a Customer has become impaired, a money deposit or other guarantee satisfactory to the Company may be required as security for the payment of bills for Service before the Company will commence or continue Service. If a residential Customer's Service has been terminated for non-payment of bills, the Company may not condition restoration of Service on payment of a deposit unless said deposit had been included as a charge on prior bills, or prior notice to the Customer had been given. (See NJAC 14:3-3.4)

Section 3 - Billings, Payments, Credit Deposits & Metering

3.10 Amount of Credit Deposit: The deposit from the Customer shall be not less than twice the estimated or actual bill for a single billing period at the applicable rate. In the case of a Customer taking Service for less than 30 days, a credit deposit may be required in an amount equal to the estimated bill for such temporary period. The Company will issue a receipt to each Customer making a deposit. (See NJAC 14:3-3.4)

3.11 Interest on Credit Deposit: All money deposits under Section 3.09 shall bear simple interest payable at the rate and in the manner specified under NJAC 14:3-3.5(d). Deposits shall cease to bear interest upon termination of Service.

3.12 Return of Credit Deposit: Upon termination of Service and payment in full of all unpaid bills for Service, the Company will return the deposit plus accrued interest, or will deduct from the deposit and interest all amounts due and return the difference, if any, to the depositor. The Company shall have a reasonable time in which to read meters and to ascertain that the obligations of the Customer have been fully performed before being required to return any deposit. The credit deposit is not a floating credit available to be used by the Customer for the payment of interim bills for service, but the Company may apply the deposit and any accrued interest against any unpaid bills and require the Customer, as a condition on continuing Service, to restore the deposit to an amount, determined in accordance with the principles set forth in Sections 3.09 and 3.10, sufficient to secure the payment of future bills. Residential customer accounts will be reviewed at least once every year and non-residential Customer accounts at least once every two years. Should such review indicate that the Customer has established satisfactory credit with the Company, the credit deposit plus accrued interest, if any, will be returned to the depositor. Such return of a credit deposit shall not serve to waive the Company's right to re-establish the credit deposit as required herein above. The Company may require surrender of the receipt issued when the deposit was made, or in lieu thereof, proof of identity before returning the deposit or any part thereof. (See NJAC 14:3-3.5)

3.13 Final Bill: A customer intending to discontinue Service shall give the Company reasonable notice thereof and arrange for the reading of the meter. Where the Customer is discontinuing all Service, the reading shall be regarded as a final reading and the Company will read the meter within forty-eight hours of receipt of such notice unless a holiday or a weekend intervenes or the Customer desires otherwise. If, because of conditions occasioned by the Customer, or by reason of compliance with the Customer's request, the final reading of the meter must be obtained outside of regular business hours, the Customer will be subject to the service charges specified in the applicable Service Classification within this Tariff.

Whether or not the Customer gives notice of discontinuance, the Customer shall be liable for Service delivered to the premises until the final reading of the meter can be obtained by the Company. Where the Customer is discontinuing all Service, the bill for Service rendered until the final meter reading, plus all other charges due and any applicable minimum charge for the unexpired term of a contract, is due and payable immediately upon presentation. Where the Service in question is unmetered, a final bill shall be rendered upon discontinuance of Service.

Section 3 - Billings, Payments, Credit Deposits & Metering

3.14 Taxes on Contributions in Aid of Construction and Customer Advances or Deposits: Any contribution in aid of construction ("CIAC"), customer advance or deposit, or other like amount received from Customers which shall constitute taxable income as defined by the Internal Revenue Service may be increased to include a payment equal to the applicable current taxes incurred by the Company as a result of receiving such monies, less the net present value of future tax benefits related to the tax depreciation guideline-life applicable to the property constructed with such monies, which for transmission or distribution items shall be taken to be 20 years. The discount rate to be used for such present value calculation will be the Company's last allowed overall rate of return.

3.15 Unmetered Service: Where the Customer's equipment is of such a character and its operation is so conducted that the Customer's use of service at the Point of Delivery is substantially invariable over the period Service is supplied, thus permitting accurate determination of billing quantities by calculation based on the electrical characteristics of such equipment, the Company may omit the installation of metering equipment and, with the consent of the Customer, use the respective quantities, so determined, for billing purposes under the applicable Service Classification. The Customer shall not make any change whatever in the equipment or mode of operation thereof, Service to which is billed in the foregoing manner, without first obtaining the Company's consent in writing. If the Customer changes equipment or mode of operation, any Service to such changed equipment or operation shall be deemed unauthorized use and shall be subject to discontinuance as provided elsewhere in this Tariff.

3.16 Non-measurable Loads: Customers with equipment which creates unusual fluctuations, which cannot be measured by standard metering facilities, shall have the maximum 15-minute demand, monthly KWH, and reactive component calculated for such equipment, and added to any such measured quantities for the customer's remaining load for billing purposes under the applicable Service Classification.

3.17 Equal Payment Plan for Individual Residential Dwelling Units: The Company may, upon request by a residential Full Service Customer, determine a payment plan of twelve equal monthly payments for the Customer. Monthly payments required under this plan may be revised by the Company one time during the payment plan period as rate changes or special conditions warrant. If actual charges are more or less than the estimated amounts, billing adjustments necessary to provide for the payment of the actual charges due for Service rendered under this plan shall be made in the twelfth month of the plan, or in the event the Equal Payment Plan is terminated, on the next bill. The Company may terminate this plan at any time as to any Customer if any monthly bill rendered to such Customer under this plan is unpaid when the next monthly bill is rendered. (See NJAC 14:3-7.5)

3.18 Returned Payment Charge: A charge of $15 will be assessed against a Customer's account when a check or an electronic payment or other form of funds transfer, which has been issued to the Company, is returned by the bank as uncollectible, or otherwise dishonored by the bank from which the funds were drawn.

Section 3 - Billings, Payments, Credit Deposits & Metering

3.19 Monthly Late Payment Charge: Upon the non-receipt of payment for services provided by the Company or an Alternative Electric Supplier by a Customer receiving Service under Service Classifications GS, GST, GP, GT, SVL, MVL, ISL, LED and Rider CEP and receiving a bill for such service rendered by the Company, as opposed to a consolidated bill rendered by an Alternative Electric Supplier, except for government entities, a Late Payment Charge at the rate of 1.5% per monthly billing period shall be applied. This charge will be applied to all amounts previously billed, including any unpaid late payment charge amounts applied to previous bills, which are not received by the Company when the next regular bill is calculated. The amount of the Late Payment Charge to be added to the unpaid balance shall be determined by multiplying the unpaid balance by the monthly Late Payment Charge rate of 1.5%. (See NJAC 14:3-7.1)

3.20 Delinquent Charge: For Customers receiving Service under Service Classifications RS, RT, RGT, GS and GST, a field collection charge will be applied for each collection visit made by the Company to the Customer's premises, except Customers who qualify for protection under the standards set forth in the NJAC 14:3-3A.5 as detailed in the Stipulation of Final Settlement (Docket No. ER95120633).

3.21 Summary Billing: Upon a Customer's request and the Company's approval, a Customer with multiple Full Service accounts may receive Summary Billing, in which the billing information for the multiple accounts is reported on a single statement, for the convenience of the Customer. Summary Billing shall not be permitted for any delinquent accounts, and shall be permitted only in those cases where meter reading dates and due dates of the multiple accounts allow for Summary Billing without adversely affecting the timely payment of bills and where summary billing does not have an adverse financial impact on the Company. The Company may, in its sole discretion, discontinue Summary Billing, or charge Customers an additional amount for Summary Billing to offset any actual or potential adverse financial impact on the Company. A single due date for accounts that are billed in summary shall be established by the Company and provided to the Customer. Summary Billing shall not commence unless and until the Customer agrees to the due date established for such Summary Billing.

3.22 Special Billing: The Company shall consider all requests from Customers to deviate from the Company's standard billing practices and procedures, including those described in this Tariff. The Company may, in its sole discretion, agree to provide special billing to a Customer, subject to, a payment by the Customer of all costs associated with the Company providing such special billing.

3.23 Metering: The Company shall maintain, install and operate meters and related equipment as necessary to measure and record the Customer's consumption and usage of all services provided under this Tariff. The Company may, in its sole discretion, install such meters and related equipment (including, but not limited to, telemetering equipment) it deems reasonable and appropriate to provide service to Customers under this Tariff. The Company may, in its sole and exclusive discretion, install such special metering as may be requested by a Customer, subject to the Customer paying all of the Company's material, labor, overheads and administrative and general expenses relating to such facilities.

The Company shall conduct inspections and tests of its meters in accordance with prudent electric practices and as otherwise prescribed by the BPU.

Section 3 - Billings, Payments, Credit Deposits & Metering

3.23 Metering: (Continued)

If requested by the Customer, the Company may, in its sole discretion, elect to provide kilowatt-hour pulses and/or time pulses from the Company's metering equipment. All costs for providing the meter pulses shall be paid by the Customer. If a Customer's consumption of kilowatts and/or kilowatt-hours increases as a result of interruptions or deficiencies in the supply of pulses for any reason, the Company shall not be responsible or liable, for damages or otherwise, for resulting increases in the Customer's bill.

If requested by a Customer, the Company may, in its sole discretion, elect to provide metering to a service location other than what is presently installed or otherwise proposed to be installed by the Company at that location. All costs for special metering facilities provided by the Company, including, but not limited to, all material, labor, overheads and administrative and general expenses, shall be billed to and paid by the Customer.

3.24 Advanced Metering Opt-Out

Any Full Service Customer or Delivery Service Customer who declines to have an AMI meter installed when notified, requests the transmitter of an AMI meter be disabled or requests an AMI meter be removed for a digital non-AMI meter, will be classified as having opted-out of AMI metering and shall be subject to the following terms:

1.) Monthly Meter Reading – A monthly fee of $15.00 shall apply to any customer who: refuses to allow the Company to install an AMI meter; requests that the transmitter of an AMI meter be disabled; or requests that an AMI meter be removed.

2.) Meter Replacements – Customers shall be charged a one-time fee of $44.46 for the replacement of an AMI meter with a non-AMI meter. The replacement meter will be manually read. This fee will also apply to any customer who elects to participate in AMI metering after requesting the removal of such meter.

3.) Access to Premises – Customers who Opt-out of AMI metering must provide reasonable access for meter reading and meter maintenance that free of safety hazard to customers, the public or the utility personnel or facilities If the customer fails to provide access for two months in a twelve-month period, then the customer will be required to: (a) relocate their metering equipment to an external location, at the customer's expense; or (b) permit the Company to reinstall an AMI meter or enable the AMI meter transmitter feature.

Customers who are taking service under a time differentiated rate, billed with time dependent rates or are involved in net metered generation will not have the option to opt out of having a smart meter.

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Section 4 - Supply and Use of Service

4.01 Continuity of Service: The Company will use reasonable diligence to maintain a regular and uninterrupted provision of Service, but should the Service be interrupted, curtailed, suspended, or discontinued by the Company for any of the reasons set forth in Section 7 of these Standard Terms and Conditions, or should the Service be interrupted, curtailed, deficient, defective, or fail by reason of any natural disaster, accident, act of a third party, strike, legal process, governmental interference or by reason of compliance in good faith with any governmental order or directive, notwithstanding that such order or directive subsequently may be held to be invalid, or other causes whatsoever beyond its control, the Company shall not be liable for any loss or damage, direct or consequential, resulting from any such suspension, discontinuance, interruption, curtailment, deficiency, defect, or failure. The Company will not be responsible for any damage or injury arising from the presence or the use of Service provided to the Customer by the Company after it passes from the Company's facilities to the Point of Delivery, unless such damage or injury is caused by the sole negligence or willful misconduct of the Company. Any damage or injury arising from occurrences or circumstances beyond the Company's reasonable control, or from its conformance with standard electric industry system design or operation practices, shall be conclusively deemed not to result from the negligence of the Company. Due to the sensitive nature of computers and other electric and electronically controlled equipment, Customers, especially three-phase Customers, are advised to and should provide protection against such variations in power and voltage supply.

4.02 Temporary Service: Service for a temporary or short term period will be provided and billed under the applicable Service Classification when the Company's available installed facilities are of adequate capacity to render such Service, provided the Customer pays in advance the estimated net cost of installing and removing all facilities provided to furnish such Service. If the total period of temporary Service is less than one month, the total billing for such period shall not be less than the stated monthly minimum of the applicable Service Classification. At the option of the Company, bills for temporary Service may be prorated and rendered at periodic intervals of less than one month and are due and payable upon presentation. The Company's specifications for the Customer's installation are available from the Company upon request.

4.03 Transformation Facilities for Transmission Customers: Where, for the mutual convenience of the Company and Customer, the transformation equipment at a delivery point is utilized by both parties, the Company will provide such facility at a monthly charge of 1.5% of the prorated cost. The prorated cost shall be (1) the product of (a) the highest 15-minute demand (rounded to the next highest 100 KW) established by the Customer on such commonly-used transformation facility since Service was originally established, and (b) the Company's book cost of such commonly-used transformer substation less those items of equipment devoted solely to uses other than supplying the Customer, (2) divided by the maximum capability of the transformation equipment when operating under load conditions. In the event that the transformer bank's maximum capability is altered, either by changes in the transformers, the transformer cooling equipment, or in the characteristics of the Customer's load, item (2) above shall be redetermined to reflect the changed conditions.

Section 4 - Supply and Use of Service

4.04 Emergency Curtailment of Service: The Company may curtail or discontinue the provision of Service to any Customer, upon reasonable notice if possible, in the event it becomes necessary to do so in case of emergencies or in compliance with an order or directive of Federal, State, or municipal authorities. The Company may interrupt Service to any Customer or Customers in an emergency threatening the integrity of its system or to aid in the restoration of Service if, in its sole judgment, such action will alleviate the emergency condition and enable it to continue or restore Service consistent with the public welfare. (Also see Sections 4.01 and 7.02) In the event of an actual or threatened restriction of fuel supplies available to its system or the systems to which it is directly or indirectly connected, the Company may curtail or interrupt Service or reduce voltage to any Customer or Customers if, in its sole judgment, such action will prevent or alleviate the emergency condition. (See NJAC 14:3-3A.1)

4.05 Special Company Facilities: At the Customer's request, or as required, subject to approval by the Company, the Company will furnish and install on its system, special, substitute, or additional facilities to meet the Customer's special or additional requirements or to protect the Company's system from disturbance of standard voltage regulation that otherwise would be caused by the operation of customer's equipment. When the Company furnishes facilities not normally supplied or when the estimated or actual cost of such special substitute or additional facilities exceeds the estimated cost of the standard facilities that normally would be supplied by the Company without special charge, either (a) the Customer shall pay in a manner to be agreed upon a facilities charge annually amounting to 18% of such additional cost, or (b) by mutual agreement the Customer may pay an amount equivalent to such additional cost, plus applicable taxes. However, alternative (a) shall not be available unless the facilities are such as are commonly and usually transferred from place to place for use in the Company's system or are reasonably capable of reuse. The Customer may also be subject to other monthly or special charges in order to meet their special needs.

4.06 Single Source of Energy Supply: No Customer may maintain or operate any source of electric energy on his premises or at his contract location in a manner whereby such source may become interconnected with the Company's facilities without the prior written approval of the Company. Such prior approval may be conditioned, among other things, on the installation and operation by the Customer at the Customer's cost and expense of such switches and/or protective devices as the Company may deem necessary to prevent injury to persons or damage to property of either the customer or the Company. Such approved interconnection may be maintained only at the appropriate rates and charges as provided in this Tariff.

4.07 Changes in Customer's Installation: The Customer, prior to making any material increase or decrease in Connected Load, demand, or other conditions of use of Service or change of purpose, arrangement, or characteristics of electrical equipment, shall notify the Company of such intention so that the Company may determine if any changes in its distribution facilities or in the Point of Delivery will be required in order that safe, adequate, and proper Service may be supplied to the Customer under the proposed changed conditions. Prior to starting any work, the Customer or his agent shall submit for the Company's approval sufficient copies as required of the plans of such proposed installations, together with a list of the principal apparatus to be used. The Company will advise the Customer if any feature of the proposed changed conditions would be incompatible with such Service. (Also see Section 5.06) Such proposed changes in the Customer's Service conditions shall not be made effective until they have been approved by the Company.

Section 4 - Supply and Use of Service

4.08 Customer's Liability to Company: Failure of the Customer to give prior notice of changes in conditions as described in Section 4.07 shall render the Customer responsible and liable for any personal injury and any property damage caused by the changed conditions, including damage to the Company's property and injury to its employees. In those cases where the Customer's bill is based on the connected load, failure to give notice of changes therein will not relieve the Customer from liability for payment of proper charges for Service based upon such changed conditions from the date such change first occurred, nor entitle the Customer to a refund or adjustment if the charges billed exceed the amount that would normally be applicable under the changed conditions.

4.09 Request for Relocation of, or Work on, Company Facilities: When the Company is requested to relocate or work on its facilities and such relocation or work is for the purpose of enabling the Customer to work on or maintain his electrical facilities or building, or perform work or construction safely in the vicinity of Company equipment, the Customer shall pay to the Company, in advance of any relocation or work by the Company, the estimated cost to be incurred by the Company in performing such relocation or work. For work of a routine nature frequently performed within the Company's service area, the Company may specify a flat fee based upon the average costs of performing such work. (Also see Sections 6.04, 6.06, and 6.08)

4.10 Liability for Supply or Use of Electric Service: The Company will not be responsible for the use, care, condition, quality or handling of the Service delivered to the Customer after same passes beyond the point at which the Company's service facilities connect to the Customer's wires and facilities. The Customer shall hold the Company harmless from any claims, suits or liability arising, accruing, or resulting from the supply to, or use of Service by, the Customer.

4.11 Relocation of Meters or Service Equipment: Where meter locations are changed from indoor to outdoor, the Company may permit feeding back from the new meter location to the original Service Entrance. When an existing Service Entrance is to be changed, the old Service shall remain active and properly metered until the old Service is disconnected and the new Service is reconnected. When it is impractical to comply with this requirement, the Company must be contacted and arrangements made to accomplish the changeover. Metered and unmetered conductors will not be permitted in the same conduit or raceway, except in special cases where Company approval has been obtained.

4.12 Liability for Acts of Alternative Electric Suppliers: The Company shall have no liability or responsibility whatsoever to the Customer for any agreement, act or omission of, or in any way related to, the Customer's Alternative Electric Supplier.

Section 5 - Customer's Installation

5.01 General Requirements: The Customer's installation must conform to the Company's specifications and all requirements of municipal and State authorities and regulations set forth in the National Electric Code in effect at the time of such installation. The Company will, however, install and maintain facilities on the Customer's premises at the Customer's cost when the Company determines such installation and maintenance to be necessary or more convenient for the delivery of Service and there is mutual agreement as to the installation and maintenance cost. Where for engineering or operating reasons it is necessary or desirable to install a substation, transformers, capacitors, control, protective or other equipment on the Customer's premises in order to supply the Service required by the Customer, the Customer shall provide a suitable place and housing for such facilities. The Company's specifications for the Customer's installation are available from the Company upon request.

5.02 Service Entrance: The Customer's Service Entrance facilities shall extend from the Point of Delivery specified by the Company to an approved entrance switch cabinet located on the Customer's premises. With the exception of metering equipment and related facilities furnished by the Company, all of the facilities necessary to conduct electricity from the Point of Delivery to the Customer's circuits shall be installed, owned, and maintained by the Customer. The Customer must provide and install an approved service head and assure all fittings used in the Service Entrance provide a water-tight connection. At least three feet of wire must be left for the connection to the Service Drop on all services. (Specifications for service installations will be furnished by the Company upon request.)

5.03 Inspection and Acceptance: The Company may refuse to connect with any Customer's installation or to make additions or alterations to the Company's Service Connection when such installation is not in accordance with the National Electrical Code, or with the Company's requirements, or where a certificate approving such installations has not been issued by an electrical inspection authority certified by the New Jersey Department of Community Affairs for the area in which the installation is located, or by a City or County Inspection Authority having exclusive authority to make electrical inspection in such area. (See NJAC 14:3-8.3(g) and (h))

5.04 Special Customer Facilities: The Customer shall furnish at his own expense any special facilities necessary to meet his particular requirements for Service at other than the standard conditions specified under the provisions of the applicable Service Classification. (Also see Section 5.05)

5.05 Regulation of Power Factor: The Company shall have the right to require the Customer to maintain a power factor in the range of 87% to 100% coincident with the Customer's maximum on-peak monthly demand and to provide, at its sole expense, any corrective equipment necessary in order to do so. The Company may inspect the Customer's installed equipment and/or place instruments on the premises of the Customer in order to determine compliance with this requirement, as deemed appropriate by the Company. The installation by the Company of corrective devices necessary for compliance with this provision, shall, as deemed appropriate by the Company, be billed to the Customer under the provisions of Section 4.05. The Company is under no obligation to serve, or to continue to serve, a Customer who does not maintain a power factor acceptable to the Company. (Also see Sections 5.01 and 5.04)

Section 5 - Customer's Installation

5.06 Change in Point of Delivery: In the event that the Company shall be required by any governmental authority to relocate its distribution facilities or to place any portion of them underground, the Customer shall at its own expense make such changes in its Service Entrance and/or in its underground Service Connection as may be necessary in order to conform to the new Point of Delivery specified by the Company. Any change requested by the Customer in the location of the existing Point of Delivery, if approved by the Company, will be at the expense of the Customer.

5.07 Liability for Customer's Installation: The Company will not be liable for damages to or injuries sustained by the Customer or others, or by the equipment or property of Customer or others, by reason of the condition, character, or operation of the Customer's wiring or equipment, or the wiring or equipment of others.

5.08 Meter Sockets and Current Transformer Cabinets: Upon the Company's designation of a Point of Delivery at which its Service line will terminate, the Customer shall provide, at its sole cost and expense, a place suitable to the Company for the installation of metering and all other electric facilities needed for the provision of electric energy by the Company or an Alternative Electric Supplier. It shall be the Customer's responsibility to furnish, install, and maintain self-contained meter sockets and current transformer cabinets in accordance with Company specifications which are available upon request.

5.09 Restricted Off-Peak Water Heater Specifications: Service supplied under Service Classification RS - Residential Service, Special Provision (a), or Service Classification GS - General Service Secondary, Special Provision (d), must conform to the following requirements as well as any other applicable conditions of Service:

(a) The minimum capacity of the water heater should not be less than 50 gallons.
(b) Should the water heater have two non-inductive heating elements, each shall be controlled by its own thermostat and both shall be electrically interlocked to prevent simultaneous operation, with the upper heating element located to heat the top one-quarter of the tank volume and the lower element located to heat the entire tank.
(c) The upper heating element may be wired to operate during the on-peak as well as off-peak periods, whereas the lower element, or single element (in a one-element water heater), may operate only during the off-peak periods.
(d) The wattage of each heating element shall not be in excess of 30 watts per gallon of tank volume, rounded to the nearest 500 watts.
(e) Service to water heaters will be supplied at single-phase 208 or 240 volts, depending on the voltage available. For the supply of equipment with one tank or a combination of tanks in excess of 250 gallons or in excess of 7500 watts, the Company must be consulted for installation specifications.

Section 5 - Customer's Installation

5.10 Restricted Controlled Water Heating Specifications: Service supplied under Service Classification RS - Residential Service, Special Provision (b), or under Service Classification GS - General Service Secondary, Special Provision (e), must conform to the following requirements as well as any other applicable conditions of Service:

(a) The water heater shall have two non-inductive heating elements, each controlled by its own thermostat and electrically interlocked to prevent simultaneous operation.
(b) The upper heating element shall be located to heat the top one-quarter of the tank volume and the lower element located to heat the entire tank.
(c) The wattage of each element shall not be in excess of 35 watts per gallon of tank volume rounded to the nearest 500 watts for water heater of 40 gallons or more.
(d) Thirty-gallon water heaters may contain either one or two heating elements, with an element size not to exceed 1500 watts.

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Section 6 - Company's Equipment on Customer's Premises

6.01 Ownership, Maintenance and Removal: The Company shall furnish, install and maintain the meters, related equipment and facilities necessary for Service unless otherwise stated. All facilities and equipment supplied by the Company shall remain exclusively its property. The Company may remove such facilities and equipment from the premises of the Customer after termination of Service.

6.02 Customer's Responsibility: Under certain circumstances, it may be necessary for the Company to install equipment on the Customer's premises. This equipment may be placed in vaults, manholes, hand-holes, outdoor substations on concrete pads, etc. These Customer-owned facilities must be constructed in accordance with all applicable codes and to the Company's specifications. Prior to starting work, the Customer or his agent shall submit for the Company's approval plans of such proposed installations, together with a list of the principal apparatus to be used. The Customer shall be responsible for the protection and safe-keeping of the facilities and equipment of the Company while on the Customer's premises and shall not permit access thereto except by duly authorized governmental officials and representatives of the Company. The Customer should notify the Company immediately if any question arises as to the authority or credentials of any person claiming to be a governmental official or a Company representative. Any malfunction or defect in the Company's equipment observed by the Customer should be reported to the Company immediately. (See Section 6.04)

6.03 Access to Customer's Premises: The Company shall have the right to construct, operate, modify, replace and/or maintain any and all facilities it deems necessary to render Service to the Customer and adjoining customers upon, over, across and/or under lands owned or controlled by the Customer. The Company shall have the right of reasonable access to all property furnished by the Company, at all reasonable times for the purpose of inspection of any premises incident to the rendering of service, reading meters, or inspecting, testing, or repairing its facilities used in connection with providing the Service, or for the removal of its property. The Company shall have the right to enter upon the lands owned or occupied by the Customer for the purpose of moving, removing, replacing, altering, accessing, servicing or maintaining any structures, fixtures, equipment, instruments, meters or other property owned by the Company, above or beneath such lands, and shall have the right to trim, cut, move, clear or destroy any trees, shrubs, plants or other growth on such lands as necessary to keep or prevent same from endangering or interfering with the Company's structures, fixtures, equipment, instruments, meters or other property, or with the providing of safe, adequate and reliable Service. The Customer shall obtain, or cause to be obtained, all permits needed by the Company for access to the Company's facilities. Access to the Company's facilities shall not be given except to authorized employees of the Company or duly authorized governmental officials. During an alleged diversion of Service, it is the Company's responsibility to obtain access to the Company’s equipment in accordance with NJAC 14:3-3.6 and 6.8. (See Section 7.03)

Section 6 - Company's Equipment on Customer's Premises

6.04 Tampering: In the event it is established that the Company's wires, meters, meter seals, switch boxes, or other equipment (including, but not limited to, revenue protection locks, meters and other devices) on the Customer's premises have been tampered with, the Customer shall be required to bear all of the costs incurred by the Company including, but not limited to, the following: (a) investigations, (b) inspections, (c) costs of prosecution including legal fees, and (d) installation of any protective equipment deemed necessary by the Company. Furthermore, where tampering with the Company's or Customer's facilities results in incorrect measurement of the Service, the Customer shall pay for such Service as the Company may estimate from available information to have been used on the premises but not registered by the Company's meter or meters. Tampering with the Company's facilities is punishable by fine and/or imprisonment under New Jersey law. (See NJAC 14:3-7.8)

6.05 Payment for Repairs or Loss: The Customer shall pay the Company for any damage to or any loss of Company's property located on the Customer's premises caused by the act or negligence of the Customer or his agents, servants, licensees or invitees or due to the Customer's failure to comply with the applicable provisions of this Tariff.

6.06 Service Disconnection and Meter Removal Authorized: A licensed electrician or an electrical contractor, upon notifying the Company, will be authorized to disconnect and permanently reconnect a single-phase secondary overhead service that is 200 amps or less. Disconnections or meter removals performed by persons other than authorized licensed electricians, authorized electrical contractors, or authorized Company personnel are prohibited and shall constitute tampering. (See Sections 6.07 and 6.08)

6.07 Reconnection of Service or Replacement of Meter: The Company shall have sole authority to reconnect a service or replace a meter. However, upon contacting the Company, a licensed electrician or electrical contractor may be authorized to reconnect a service or reinstall the meter upon completion of his work as provided in Section 6.06. (See Section 4.09)

6.08 Sealing of Meters and Devices: It is the practice of the Company to seal all meters. Service Entrance switches, wiring troughs, or cabinets connected ahead of meters or instrument transformers, will be sealed by the Company. When Service is introduced prior to the completion of the wiring, or where Service is discontinued, the Company or its designated agent may seal all Service equipment. No one except an authorized employee of the Company is permitted to remove a Company seal or padlock, except as provided in Section 6.06.

6.09 Power Disturbance Protection Service: The Company shall offer to provide the following to Customers which request power disturbance protection: (a) diagnostic services to identify the probable cause of electrical disturbance, (b) engineering analysis and design to develop a power conditioning solution, (c) electrical system modification and/or power conditioning equipment installation, and (d) maintenance of the power conditioning systems. Charges for such Service shall be not less than the actual cost to provide such Service. The Company shall not be liable for damage or injury arising from the improper use of power disturbance protection/conditioned power service, systems or equipment, or for any costs or damages attributable to injury or the loss of the Customer's business, production or facilities resulting from the failure of power disturbance protection/conditioned power service, systems or equipment.

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Section 7 - Suspension or Discontinuance of Service

7.01 Work on Company's Facilities: The Company may, upon reasonable notice when it can be reasonably given, suspend, curtail, or interrupt Service to a Customer for the purpose of making repairs, changes, or improvements to or in any of its facilities either on or off the Customer's premises.

7.02 Compliance with Governmental Orders: The Company may curtail, discontinue, or take appropriate action with respect to Service, either generally or as to a particular Customer, as may be required by compliance in good faith with any governmental order or directive, and shall not be subject to any liability, penalty, or payment, or be liable for direct or consequential damages by reason thereof, notwithstanding that such instruction, order or directive subsequently may be held to be invalid or in error. Verbal or written orders of police, fire, public health, or similar officers, acting in the performance of their duties, shall be deemed to come within the scope of this subsection. (See Sections 4.01 and 4.04)

7.03 Customer Acts or Omissions: The Company may, upon giving reasonable notice to the Customer when it can be reasonably given, suspend or discontinue Service and remove the Company's equipment from the Customer's premises for any of the following acts or omissions:

(a) Non-payment of any valid bill due from the Customer or the Customer's resident spouse for Service furnished by the Company at any present or previous location. However, non-payment for business Service shall not be a reason for discontinuance of residential Service, except in cases of diversion of Service. (See Section 3.08)
(b) Tampering with any of the Company's facilities. (See Section 6.04)
(c) Fraudulent representation or application in relation to the use of Service. (See Section 1.03)
(d) Moving from the premises, unless the Customer has requested the Company to continue Service at the Customer's expense. (See Section 2.06)
(e) Resale, transfer, or delivering any part of the Service supplied by the Company to others without the Company's permission. (See Section 1.05)
(f) Refusal or failure to make or increase an advance payment or credit deposit as provided for in this Tariff. (See Section 3.09)
(g) Refusal or failure to contract for Service when reasonably required by the Company to do so. (See Section 2)
(h) Connecting and operating equipment so as to produce disturbing effects on the Company's system or Service to other Customers. (See Section 1.06)
(i) Refusal or failure to comply with any provisions of this Tariff.
(j) Where, in the Company's opinion, the condition of the Customer's installation presents a hazard to life or property.
(k) Refusal or failure to correct any faulty or hazardous condition of the Customer's installation.
(l) Refusal of reasonable access to Customer's premises for necessary purposes in connection with rendering of Service, including meter installation, reading or testing, or the maintenance or removal of the Company's property.

Failure by the Company to exercise its rights shall not be deemed a waiver thereof. (See NJAC 14:3-3A.1)

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Section 7 - Suspension or Discontinuance of Service

7.04 Reconnection of Service: When Service has been discontinued by reason of any act or omission or default of the Customer, the Company will not restore service to the Customer's premises until the Customer has made proper application therefor and has rectified the condition or conditions that caused the discontinuance. It is further required that the Customer shall have paid all amounts due as provided in this Tariff including the Service Charge of the applicable Service Classification to reimburse the Company in part for the cost of special handling of the account and of the special costs associated with the disconnection and reconnection of Service.

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Section 8 - Service Connections

8.01 General: This Section governs situations in which the Company's distribution lines and facilities are of adequate capacity to serve the Customer's load and are located adjacent to the Customer's premises. In these situations, the connection between the Company's system and the Customer's installation shall be made by the Company and established in accordance with the provisions of this Section.

8.02 Overhead Service Connection: The Company will install, connect, and maintain at its own cost and expense not more than one Service Drop for each contract location. The Company shall not be required to install a Service Drop where its length would exceed the safe distance over which a single span of Service Drop conductors can be placed.

8.03 Underground Secondary Service Connection (other than a manhole duct system) to Serve an Individual Residential Customer/Applicant: (a) A residential Customer or Applicant electing an underground Service Connection instead of an overhead Service Connection can elect to install such connection at his/her own cost and expense in accordance with the Company's specifications for such construction. At the Customer's option, the Company will install and connect such underground Service Connection, upon the Customer making a non-refundable contribution, as described in (b) below. In either case, the Company will assume ownership and responsibility for maintenance, including replacement when appropriate, at the Company's expense, of the underground Service Connection upon connection to the Company's system (subject to receipt of requisite easements, rights of way or the like, at no cost to the Company). In addition, at the Customer's option, the Company will assume ownership and responsibility for maintenance, including replacement when appropriate, at the Company's expense, of all private residential underground Service Connections installed prior to the date of this tariff sheet (subject to receipt of requisite easements, rights of way or the like, at no cost to the Company). In connection with any Company work performed under this Section 8.03, whether on Company-owned or Customer-owned facilities, the Company must first be granted the right by the Customer to trim or remove vegetation and to remove structures or other obstructions that interfere with such work and the Company will not be responsible for the costs of repair, replacement or restoration thereof.

(b) The non-refundable contribution will be equal to the predetermined unit cost differential of furnishing such facilities underground instead of overhead. If the Customer provides the trench, the underground Service Connection charge will be credited accordingly.

Section 8 - Service Connections

8.04 Underground Distribution Service Connection to Serve a Non-Residential Customer: Where a non-residential Customer or Applicant elects such underground Service Connection instead of an overhead Service Connection, or where an overhead or secondary network system is not available, the Customer or Applicant, or the Company at the Customer or Applicant's discretion, must install such connection at the Customer or Applicant's own cost and expense in accordance with the Company's specifications for such construction. The Service Connection will be made by the Company, and shall be owned and maintained, and when necessary, relocated in accordance with the Company's specifications, by Customer at the Customer's own cost and expense.

8.05 Underground Distribution Service Connection (other than a manhole duct system) in Residential Subdivision: Where distribution circuits have been extended underground pursuant to Tariff Part II, Section 10, the Service Connection shall be installed underground as part of the entire electrical system for the development upon payment of the applicable charges computed in accordance with Appendix A of these Standard Terms and Conditions.

8.06 Conventional Underground Service Connection (Secondary Network System): If a Customer's or Applicant's facility is located in a designated network system, one conventional underground Service Connection to each contract location will be provided by the Company without cost to the Customer which shall terminate at a point not more than 30 feet distant from the curb, measured at right angles to the curb, nearest the point of connection to the Customer's facilities, provided, however, that the Company will not supply a Service Connection in whole or in part under or within a building except that portion extending through the building wall. When the required length of Service Connection exceeds the foregoing, the Customer shall have the option of terminating his facilities at either (1) a splice box acceptable to the Company installed, owned, and maintained by the Customer at a point within the distance limit described above, or (2) at the discretion of the Company, in the nearest available splice box or manhole provided in and as part of the Company's normal underground distribution system. All connections between the Customer's and Company's facilities shall be made by the Company.

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Section 9 - General Interconnect Requirements for On-Site Generation

9.01 The following requirements and standards for connection of generating facilities located on Customer's premises to the Company system shall be met to assure the integrity and safe operation of the Company system with no deterioration to the quality and reliability of service to other Customers. The operation of the generation facility should be done in a competent manner, such that the Company system as a whole is protected.

9.02 All small power producers or cogenerators shall make application to the Company for approval to interconnect their facilities with the Company system.

9.03 The Company shall require the following as part of the application:

(a) Plans and specifications of the proposed installation.
(b) Single line diagram and details of the proposed protection schemes.
(c) Instruction manuals for all protective components.
(d) Component specification and internal wiring diagrams of protective components if not provided in instruction manuals.
(e) Generator data required to analyze fault contributions and load current flows including, but not limited to, equivalent impedances and time constants.
(f) All protective equipment's ratings if not provided in instruction manuals.
(g) Evidence of insurance satisfactory to the Company.
(h) An agreement to indemnify and hold harmless the Company from any and all liability or claim thereof for damage to property, including property of the Company and injury or death to persons resulting from or caused by the presence, operation, maintenance or removal of such installation.

9.04 The Company shall within 30 days from the receipt of all required data from the Applicant either approve or reject in writing the application for connection to the Company system. Rejection of an application shall state with specificity the reasons for such rejection. Connection to the Company system will be permitted only upon obtaining the formal approval of the Company. The Company may require the execution of a formal application form and/or interconnection agreement by the customer.

9.05 The installation of the generation facilities must be in compliance with the requirements of the National Electrical Code and all applicable local, State and federal codes or regulations. The installation shall be undertaken and completed in a workmanlike manner, and shall meet or exceed industry acceptance standards of good practice. The provisions of the National Electrical Safety Code and the standards of the Institute of Electrical and Electronics Engineers, National Electrical Manufacturers Association and the American National Standards Institute shall be observed to the extent that they are applicable. Prior to connection, the Company must be provided with evidence that electrical inspection by an authorized inspection agency indicates that the above items were completed in a manner satisfactory to the Company.

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Section 9 - General Interconnect Requirements for On-Site Generation

9.06 The generation facility shall have the following characteristics:

(a) Interconnection voltage shall be compatible and consistent with the system to which the Company determines the generation facility is to be connected.
(b) The generation facility shall produce 60 Hertz sinusoidal output compatible with the Company system to which the facility is to be connected.
(c) The generation facility must provide and maintain automatic synchronization with the Company system to which it is to be connected.
(d) The break point between the generation facilities producing single-phase or three-phase output shall be in accordance with existing Company motor specifications or as otherwise specified by the Company.
(e) At no time shall the operation of the facility result in excessive harmonic distortion of the Company wave form. Total harmonic distortion greater than 5% shall be deemed excessive and shall result in disconnection of the facility from the Company system.
(f) The installation of power factor correction ("PFC") capacitors at the facility may be required under conditions to be determined by the Company when necessary to assure the quality and reliability of service to other Customers. The cost of PFC capacitors shall be borne by the Customer.
(g) The cost of supplying and installing 15-minute integrated generation output metering, and any other special facilities or devices occasioned by the generation facility which the Company may deem necessary on its system, such as telemetry and control equipment, shall be borne by the Customer.

9.07 The Customer shall provide automatic disconnecting devices with appropriate control devices which will isolate the facility from the Company system within a time period specified by the Company for, but not necessarily limited to, the following conditions:

(a) A fault on the Customer's equipment.
(b) A fault on the Company system.
(c) A de-energized Company line to which the customer is connected.
(d) An abnormal operating voltage or frequency.
(e) Failure of automatic synchronization with the Company system.
(f) Loss of a phase or improper phase sequence.
(g) Total harmonic content in excess of 5%.
(h) Abnormal power factor.

The devices shall be so designed and constructed to prevent reconnection of the facility to the Company system until the cause of disconnection is corrected.

9.08 The Company shall reserve the right to specify settings of all isolation devices which are part of the generation facility.

Section 9 - General Interconnect Requirements for On-Site Generation

9.09 The Company shall require initial inspection and testing as well as subsequent inspection and testing of the facility's isolation and fault protection systems at the Customer's expense on an annual basis. Maintenance of these systems must be performed and documented by the customer at specified intervals to the satisfaction of the Company. The Company shall reserve the right to disconnect the customer and/or the generation equipment from the Company system for failure to comply with these inspections, testing and maintenance requirements.

9.10 The Customer is solely responsible for providing adequate protection for the equipment located on the Customer's side of the interconnection system. This protection shall include, but not be limited to, negative phase sequence voltage on three-phase systems.

9.11 The Customer shall provide a Company-controlled disconnecting device providing a visible break on the Company side of the interconnection system. The Company shall require that this device accept a Company-provided padlock. The Company may also require manual operation of the device when required. The Company shall require this device to be labeled "Cogeneration Disconnection Switch" and located outside the facility such that 24-hour access is possible.

9.12 The Customer shall agree to grant access to the Company's authorized representative during any reasonable hours to install, inspect and maintain the Company's metering equipment.

9.13 The Customer must satisfy, and shall be subject to, all terms and conditions of the Company's Tariff for Service.

9.14 No wind generator, tower structure or device shall be installed at a location where, in the event of failure, it can fall in such a manner as to contact, land upon, or interfere with any Company lines or equipment.

9.15 The Customer shall maintain or cause to be maintained the generator and its associated structures, wiring and devices in a safe and proper operating condition so that the installation continues to meet all the requirements contained herein.

9.16 When and if any controversy arises as to the interpretation and application of these requirements and standards, the matter may be referred to the BPU for determination.

9.17 The Company reserves the right to modify or replace the Customer's service meter to prevent reverse registration from the customer's generation facility. Customers desiring to sell power to the Company should refer to Rider QFS - Cogeneration and Small Power Production Service.

Section 10 – Extension of Company Facilities (NJAC 14:3-8)

10.01 General Information: Where a line extension is necessary to provide Service to a Customer or Applicant or group of Customers, and where the request is for an extension of Company facilities to serve new customers, or where the request is for an expansion, upgrade, improvement, or other installation of plant and/or facilities by an Applicant, the procedures set forth in this Section 10 shall be utilized as a guide to determine the extent of any refundable deposit or non-refundable contribution, which may be required from the Customer or Applicant pursuant to NJAC 14:3-8. The Company shall not be precluded from entering into a mutually favorable agreement with the Customer or Applicant when it is deemed that a portion of the investment is for purposes of system improvement. This Section 10 does not apply to installation of special facilities or back-up systems which are not normally supplied by the Company. When such facilities or back-up systems are requested by the Customer, Section 4.05 shall be applicable.

For purposes of this Section 10, the following defined terms are exclusively for use in connection with this Section. Other definitions, as provided in Part I of the Company's Tariff for Service, may also be applicable to any Applicant under this Section and, where appropriate, should be used in conjunction with these terms.

The term "Applicant" means a person or an entity that requests Extension Service from the Company. An Applicant may or may not be the End User or Customer of the Company.

The term "Extension Service" refers to the construction or installation of electric distribution plant and/or facilities by the Company used to convey Service from existing or new plant and/or facilities (and includes the new plant and/or facilities themselves) to a structure or property for which the Applicant has requested Service in response to (i) an application for Extension Service from an Applicant to serve new customer(s) and/or (ii) an application for Extension Service requesting expansion, upgrade, improvement, or other installation of plant and/or facilities to serve existing customer(s). The Extension Service begins at existing plant and/or facilities and ends at the point of connection to or with the Service Connection, and includes the meter.

The term "Extension Cost" refers to the cost of construction and installation of the Extension Service based on the Company's "standard least cost design" criteria, using the Company's unitized or actual cost for materials and labor (both internal and external) employed in the design, construction, and/or installation of the Extension Service, including, but not limited to, Service Connection (subject to Section 8), metering-related costs, and including overheads directly attributable to the work, and the loading factors, such as those for mapping and design. Extension Costs may be apportioned based upon load depending on factors such as the Applicant's needs as compared to the Company's need to enhance or improve reliability, or the needs of other Applicant(s) who may be using the same facilities.

The term "refundable deposit" pertains to the non-interest bearing monies, which must be increased in accordance with Part II, Section 3.14 to provide for the associated income tax liability, that the Applicant must advance prior to the start of construction. The entire refundable deposit amount is subject to refund as set forth herein. Any portion of the refundable deposit remaining after the tenth year of service, as provided in this Section 10, is no longer subject to refund, and becomes the property of the Company. In no event shall more than the original refundable deposit be refunded.

Section 10 – Extension of Company Facilities (NJAC 14:3-8)

10.01 General Information: (Continued)

A “non-refundable contribution," which the Applicant must pay in full prior to construction, becomes the property of the Company and is not subject to refund. All non-refundable contributions must be increased in accordance with Part II, Section 3.14 to provide for the associated income tax liability.

The term "distribution revenues" utilized in this Section 10, as defined by the BPU, shall mean the total revenue, plus related sales and use tax, collected by a regulated entity from a Customer, minus basic generation service charges, plus sales and use tax on the basic generation service charges, and, unless included with basic generation service charges, transmission charges derived from Federal Energy Regulatory Commission (FERC) approved transmission charges, plus sales and use tax on the transmission charges, assessed in accordance with the Company’s Tariff for Service. This definition refers to the total amount of Delivery Service charges (which include Sales and Use Tax) from customer(s), as provided in the applicable rate schedule in Part III of the Company’s Tariff for Service.

The term "underground distribution" refers to buried distribution conductors with associated above-grade equipment.

The term "conventional underground" refers to a secondary network installed in a complete manhole and duct system with all equipment below grade level and is generally located in central sections of the more urban communities.

The term “standard least cost design” refers to the Company’s design criteria for an overhead extension of its facilities, which is based upon then-existing Company specifications as contained in the Company’s Construction Standards, Material Specifications, and Distribution Engineering Practices. These standards are developed in compliance with the current edition of the National Electrical Safety Code in order to provide reliable electric service in a cost-effective manner.

The term “alternate design” refers to an Applicant’s request for Extension Service in a particular manner that exceeds the Company’s “standard least cost design” criteria, including, but not limited to, underground requirements and the removal of existing facilities. An example of an “alternate design” requested by an Applicant would be the installation of a pad-mounted transformer adjacent to a parking lot behind a building, rather than at the front corner closest to the Company’s existing distribution circuit. The difference in cost between the “alternate design” and the “standard least cost design” shall, in all cases, be paid in full by the Applicant as a non-refundable contribution.

Section 10 – Extension of Company Facilities (NJAC 14:3-8)

10.02 Rights-of-Way: The Company shall not be required to extend or relocate its facilities for the purpose of rendering Extension Service to Applicants until rights-of-way or easements satisfactory to the Company have been obtained from government agencies and property owners to permit the installation, operation, and maintenance of the Company's lines and facilities. In connection with granting to, or obtaining for, the Company, without charge, such rights-of-way or easements as necessary for the Company's lines and facilities to be placed upon, over, across, or under property as necessary to provide the Extension Service, Applicants requiring Extension Service shall perform all initial vegetation clearance and trimming. The Company shall also be granted the right to trim or remove vegetation and to remove structures or other obstructions that might subsequently interfere with such lines and facilities, the right of access and entry without notice for Company agents and equipment necessary in the exercise of privileges under the grant, and the right to use and extend the Company's lines and facilities, and install additional lines and facilities, as deemed necessary by the Company in order to provide Service to other Customers. Any right-of-way or permit fees, either initial or recurring, or charges in connection with rights-of-way for providing Extension Service to an Applicant, shall be paid for by the Applicant.

10.03 Extension Service to the Boundary of a Subdivision (Residential and Non-Residential): Such an extension shall normally be provided overhead on public right-of-way and/or private property based upon the Company's standard least cost design criteria, but shall not be provided underground on public right-of-way unless required of, or approved by, the Company.

If the Applicant requests Extension Service that exceeds the Company's standard least cost design criteria, and the Company approves the request, the Applicant shall be required to make a non-refundable contribution equal to the additional cost of the alternate design.

The Company may require a refundable deposit of the Extension Cost, prior to construction, to be refunded as provided in Sections 10.04 or 10.05, as applicable.

Section 10 – Extension of Company Facilities (NJAC 14:3-8)

10.04 Extension Service within a Residential Subdivision: Such an extension shall not be provided overhead. It shall be provided underground based upon the Company's underground design criteria, on public right-of-way and/or private property. This Section is applicable only for new, predominantly residential areas where all the applicable provisions of the Standard Terms and Conditions of this Tariff and any applicable provisions of the New Jersey Administrative Code (NJAC) are complied with.

The Applicant shall make a non-refundable contribution for the construction cost differences between the overhead and the underground design in accordance with Appendix A of Part II of this Tariff.

If the Applicant has not obtained sale contracts for at least 20% of the total units, the Company may require a refundable deposit equal to the Extension Cost using the total unitized cost for the equivalent overhead construction.

Any refundable deposit received from the Applicant will be refunded as follows: One year after the first connection of a completed premise occupied by a bona fide owner or a responsible tenant who has entered into a contract with the Company for Service, the Company will refund a sum equal to ten times total actual distribution revenues from all such bona fide owner(s) or responsible tenant(s) during such contract year, up to (but not in excess of) the refundable deposit amount. Refunds in subsequent years, for up to nine additional years after the first year, will be equal to ten times the positive difference after subtracting: 1) the highest total actual distribution revenues that was used for calculating the refund in any previous year, from 2) the total actual distribution revenues from all such bona fide owners or responsible tenants during each such subsequent year, up to (but not in excess of) the remaining refundable deposit amount.

10.05 Extension Service to Serve Non-Residential Customers (including within Non-Residential Subdivisions), Multi-unit Residential Apartment Buildings, and Three-Phase Individual Residential Customers: Such an extension will be provided overhead based upon the Company's standard least cost design criteria, but may be provided underground as an alternate design, but shall not be provided underground on public right-of-way, unless required of, or approved by, the Company. When Extension Service is provided underground pursuant to this Section 10.05, the Applicant, or the Company at the Applicant's discretion (and at the Applicant's own cost and expense consistent with Section 10.01), shall provide all trenching and backfill in accordance with the Company's specifications.

If the Applicant requests Extension Service that exceeds the Company's standard least cost design criteria, and the Company approves the request, the Applicant shall be required to make a non-refundable contribution equal to the additional cost of the alternate design.

The Company may require a refundable deposit equal to the Extension Cost. The refundable deposit under this Section 10.05 shall be eligible for refund, up to (but not in excess of) the refundable deposit amount, as follows: At the end of the first year, the Company will refund from the refundable deposit an amount equal to ten times the total actual distribution revenues billed during that period. At the end of each subsequent year, for an additional nine years, a refund will be equal to ten times the positive difference after subtracting: 1) the highest total actual distribution revenues that was used for calculating the refund in any previous year, from 2) the total actual distribution revenues billed during each such subsequent year, up to (but not in excess of) the remaining refundable deposit amount.

Section 10 – Extension of Company Facilities (NJAC 14:3-8)

10.06 Extension Service to Serve a Single-Phase, Individual Residential Customer: Such an extension shall be provided overhead based upon the Company's standard least cost design criteria, and may be provided underground as an alternate design, but shall not be provided underground on a public right-of-way. When Extension Service is provided underground pursuant to this Section 10.06, the Applicant shall be required to provide all trenching and backfill in accordance with the Company's specifications.

The difference in cost between the alternate design and the Company's standard least cost design shall be paid in full by the Applicant as a non-refundable contribution.

When provided overhead on a public right-of-way, the Extension Service will be provided without charge or deposit requirement. When provided overhead on private property, the Extension Service will be provided without charge when the Extension Cost, based on the distance measured from the property line to the dwelling location, does not exceed ten times the estimated annual distribution revenues. A refundable deposit may be required from the Applicant for any Extension Cost in excess of ten times the estimated annual distribution revenues.

The refundable deposit under this Section 10.06 shall be eligible for refund, up to (but not in excess of) the refundable deposit amount, as follows: At the end of the first year, the Company will refund from the refundable deposit an amount equal to ten times the total actual distribution revenues billed during that period, less the estimated annual distribution revenues (used as the basis for the initial refundable deposit calculation). At the end of each subsequent year, for an additional nine years, a refund will be equal to ten times the positive difference after subtracting: 1) the highest total actual distribution revenues used for calculating the refund in any previous year, from 2) the total actual distribution revenues billed during each subsequent year, up to (but not in excess of) the remaining refundable deposit amount.

10.07 Extension Service within Conventional Underground Area: Such an extension for 600 volt systems necessary on public right-of-way shall be installed without charge or deposit requirement. Such extensions shall not be provided on private property or for other than 600 volt systems.

10.08 Extension Service Initiation: The Company shall not commence construction of the Extension Service until (a) it has received and accepted an application for service; (b) the Applicant has completely executed appropriate contracts for Service, including, but not limited to, Extension Service as set forth in this Section 10; (c) the Applicant has paid any and all associated Extension Costs or other charges, whether by way of a refundable deposit or a nonrefundable contribution as applicable; and (d) the Applicant requesting the Extension Service has furnished to the Company satisfactory rights-of-way over, across, through, in and/or on property that are acceptable to the Company and necessary for the construction, maintenance and operation of the Extension Service.

10.09 Grading Requirements: The Applicant shall perform or arrange and pay for all Company-directed rough grading in accordance with the Company's specifications for underground lines and facilities as said specifications shall be modified by the Company from time to time. The Company's specifications are available from the Company upon request.

10.10 Exceptions: No deviations from the Company's standard construction practices shall be permitted without the Company's approval. Any Company-approved deviations from said construction practices shall be at the Applicant's sole expense.

Section 11 – Third Party Supplier Standards

11.01 Tariff Governs: The Company's BPU-approved Third Party Supplier Agreement and Customer Account Services Master Service Agreement will be governed by reference to this Tariff for Service.

11.02 Uniform Agreement: The Company shall offer the same BPU-approved Third Party Supplier Agreement and Customer Account Services Master Service Agreement to all licensed entities that seek to serve as Alternative Electric Suppliers in the Company's service area by providing electric generation service to Customers located therein.

11.03 Procedure for Agreement Modification: Modifications of the Supplier Fees and Charges contained in the Company's Third Party Supplier Agreement shall be made in accordance with applicable BPU Orders, including the BPU Order dated August 17, 1999 (Docket No. EO97070460). Other modifications to the Company's Third Party Supplier Agreement must be approved by the BPU in accordance with the standards set forth in the aforementioned Order, as follows, or as otherwise directed by the BPU.

The Company shall file a written request for BPU approval of intended modifications (the "Request") with the Board. The date of filing shall be referenced herein as the "Filing Date." A copy of the filing shall simultaneously be provided, by regular mail, facsimile, hand delivery, or electronic means, to the Division of the Ratepayer Advocate, Public Service Electric and Gas, Conectiv, Rockland Electric, and to all BPU-licensed Alternative Electric Suppliers (using a list of addresses for the Alternative Electric Suppliers that shall be maintained by the BPU and made available to the Company). The mode(s) of transmission shall be selected to effectuate actual delivery of the copies within 48 hours of filing with the Board.

Should the Ratepayer Advocate or any BPU-licensed Alternative Electric Supplier wish to contest the Request, the contesting entity must file its reasons for contesting the Request, in writing, with the BPU and simultaneously serve copies thereof upon the Company and the Ratepayer Advocate. This must be done within 17 days of the Filing Date. Service upon the Company shall be made by way of the Company representative who filed the Request.

Within 45 days of the Filing Date, the BPU may issue a Suspension Order stating that the Request requires further study. Such determination would put the Request on hold, pending future action by the Board.

If the BPU does not take action on the Request within 45 days of the Filing Date, the Company may implement the intended modifications, although the BPU retains the authority to make a determination on the Request in the future.

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Section 12 – Net Metering Installations

12.01 General: For the purpose of this Section of the Tariff for Service a Customer-generator is an electricity customer such as an industrial, commercial or residential customer that generates electricity using Class 1 renewable resources as defined in NJAC 14:8-1.2 on the customer's side of the meter. Net metering, as defined in Section 12.02 below, provides for the billing or crediting, as applicable, of energy usage by measuring the difference between the amount of electricity delivered by the Company to a Customer-generator, as defined in Section 12.02 below, in a given Billing Month and the electricity delivered by a Customer-generator into the Company distribution system. The Company reserves the right to select and supply the type of meter(s) that will enable the net metering of electricity as described above.

The Customer generator shall be responsible for all interconnection costs as defined in NJAC 14:8-5.7 et seq., which shall be in addition to any other charges applicable to meet service requirements. For customers eligible for Net Metering the term usage as applied in Section 2.05 shall mean net usage as determined by Net Metering. It is the Customer-generator's responsibility to know all of the rules associated with the provision of net metering service.

12.02 Limitations and Qualifications for Net Metering: "Net metering" means a system of metering and billing for electricity in which the Company 1) credits a customer-generator at the full retail rate for each kilowatt-hour produced by a Class 1 renewable energy system installed on the customer-generator's side of the electric revenue meter, up to the total amount of electricity used by that customer-generator during an annualized period determined under NJAC 14:8-4.3 and 2) compensates the customer-generator at the end of the annualized period determined under NJAC 14:8-4.3 for any remaining credits, at a rate equal to the avoided cost of wholesale power. To qualify for Net Metering, a Customer-generator must generate Class 1 renewable energy as defined in NJAC 14:8-1.2. The Company will offer net metering to any customer that generates Class 1 renewable electricity on the customer's side of the meter provided that the generating capacity of the Customer-generator's facility does not exceed the amount of electricity supplied by the Company over an Annualized period (as defined in NJAC 14:8-4.3).

12.03 Limitations and Qualifications for Aggregated Net Metering (N.J.S.A. 48:3-87e(4)): To qualify for Aggregated Net Metering a customer must be: a state entity, school district, county, county agency, county authority, municipality, municipal agency, or municipal authority that has multiple facilities with metered accounts to be known collectively as the "Aggregated Meters." The Aggregated Meters must be: located within the Company's territory; served under the same rate schedule; all served by either Basic Generation Service or by the same Third Party Supplier; and located within the customer's territorial jurisdiction or, for a State entity, located within 5 miles of one another. One of the Aggregated Meters must operate a Class 1 solar electric power generation system using a net metered account as defined in Section 12.02, Limitations and Qualifications for Net Metering, except for the annualized electric generation capability limitation. The Qualified Customer-Generator must be located on property owned by the customer. The size of the Qualified Customer-Generator for Aggregated Net Metering is defined in Section 12.03.a, Customer-Generator Sizing Qualifications for Aggregated Net Metering.

a) **Customer-Generator Sizing Qualifications for Aggregated Net Metering:** The annualized electric generation capability of the customer's solar generating system, located at the net metered location cannot exceed the amount of electricity supplied by the electric power supplier or basic generation service provider to all of the Aggregated Meters over an annualized period. The Aggregated Meters used to determine the maximum annualized electric generation capability of the customer's solar generating system may not be used to determine the maximum annualized electric generation capability of other aggregated net metered facilities nor become a Qualified Customer-Generator as defined in Section 12.02, Limitations and Qualifications for Net Metering.

Section 12 – Net Metering Installations

12.03 Limitations and Qualifications for Aggregated Net Metering (N.J.S.A. 48:3-87e(4)): (Continued)

b) **Billing for Aggregated Net Metering**: The Qualified Customer-Generator will be billed as defined in Section 12.06, Net Metering Billing. However, Section 12.06, Net Metering Billing will not apply to the other Aggregated Meters and those meters will continue to be billed at the full retail rate pursuant to the applicable rate schedules.

c) **Incremental Costs Associated with Aggregated Net Metering:** All incremental costs incurred by the Company resulting from the implementation of Aggregated Net Metering shall be recovered from Aggregated Net Metering customers.

12.04 Limitations and Qualifications for Remote Net Metering (BPU Docket No. QO18070697, Order dated September 17, 2018):

The Clean Energy Act, P.L. 2018, Chapter 17, Section 6 required the BPU to establish an application and approval process to facilitate Remote Net Metering in which a public entity certified to act as a host customer with a solar electric energy project may allocate credits to other public entities within the same electric public utility service territory. To qualify for Remote Net Metering a customer must be a public entity, which is a State entity, school district, county, county agency, county authority, municipality, municipal agency, municipal authority or public university that has completed the BPU-approved application process and received BPU approval for certification as a participant eligible to receive Remote Net Metering credits. A host customer is a public entity that proposes to host a solar electric generation facility on its property. The entities designated to receive credits are considered to be receiving customers that are public entities located in the same electric distribution company ("EDC") territory as the host customer. Both the host customer and the receiving customer must be a customer of record of JCP&L, and there may be no more than 10 receiving customer accounts per host.

Eligible public entities must follow the established application and approval process to certify public entities to act as a host customer for Remote Net Metering, requiring submittal of the BPU-approved form of "Public Entity Certification Agreement" used by the host customers and receiving customers which shall be fully executed and provided to the Company, reviewed by the Staff of the BPU and approved by the BPU prior to the application of any Remote Net Metering credits. The Public Entity Certification Agreement is available on the New Jersey Clean Energy Program website as well as the Company's website in the section dedicated to information regarding net metering and interconnection processes. The standard form "Public Entity Certification Agreement" must be fully executed by the host customer and each receiving customer, be accompanied by the BPU-approved standard form of Interconnection Application (Part 1) as used for all net metered projects and be delivered to both BPU Staff and the Company. The Company and BPU Staff will review the Public Entity Certification Agreement for administrative completeness. Within 10 days, the Company will provide its input to BPU Staff, whereupon BPU Staff will issue a notice of its findings to the contact person listed on the form. Following the issuance of a notice of administrative completeness, the Company will have 20 business days to review the application for eligibility and feasibility, including the proposed system size and all account information and make a recommendation to BPU Staff to approve or deny. In the case of a recommendation of denial, the Company will provide to BPU Staff a description of the deficiencies and potential means to correct the deficiencies. BPU Staff will present the fully executed "Public Entity Certification Agreement" and Part 1 of the Interconnection application to the BPU with a recommendation for approval or denial.

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Section 12 – Net Metering Installations

Host Customer Solar Electric Generator Sizing for Remote Net Metering: The size of a host customer's solar electric generation facility shall be limited to the installed capacity that can produce electricity on an annual basis in an amount not to exceed the total average usage of the host customer's electric accounts with the Company. The host customer is not required to use more than one account for purposes of sizing the solar electric generation facility. However, the solar facility must be located on property containing at least one Company electric meter for the host customer. The host customer is required to identify which account(s) to use to calculate the total average usage for the previous 12 months of consumption in kWhs. The total quantity of annual, historic consumed kWh will be divided by (i) the number of accounts, if more than one account is used, and (ii) 1,200 annual kWh per kilowatt ("kWdc") to arrive at the maximum capacity for the solar electric generation facility in kWs.

Billing and Credits for Remote Net Metering: No more than 10 receiving accounts may be party to a Public Entity Certification Agreement and not less than 10% of the solar electric generating facility output may be allocated to an individual receiving account. The terms and conditions of the Public Entity Certification Agreement, including all designated receiving accounts and their associated percentage of output allocations, shall be fixed throughout the annualized period with the exception of a once per annum opportunity to reallocate upon BPU Staff's approval of a revision to a Public Entity Certification Agreement, which is re-executed with all parties' approval, including the Company. The host customer shall agree to the installation of a revenue grade production meter at its expense as specified by the Company, to record the solar generation at the host site. On a monthly basis, the Company shall use the metered kWh data produced by the solar electric generation facility on the host customer property to calculate the credits due to receiving customers. The monthly output will be allocated to receiving customers according to the percentage allotments indicated on the Public Entity Certification Agreement. The value of a Remote Net Metering credit will reflect a rough approximation of the generation, transmission and distribution value of a kWh produced by the solar electric generation facility. Each credited kWh for a receiving customer shall offset the variable kWh charges of a receiving customer(s) except for the SBC charge. No fixed, demand ($/kW), customer or SBC charges shall be offset by a remote net metering credit. On a monthly basis, the Company will credit an apportioned amount of kWh output from the solar facility in the form of kWh to be deducted from the kWh consumed by the receiving customers according to the percentage allotments indicated on the Public Entity Certification Agreement. The apportioned amount of solar electricity generated in kWh, the gross amount of electricity consumed and the net amount of kWh after credit allocation will be identified on the monthly electric bills of the designated receiving customer account. The receiving customers will be charged the SBC amounts attributable to the apportioned credit kWh. The application of an annualized period as currently used in the net metering rules at N.J.A.C. 14:8-4.2 shall apply to remote net metering. Any excess generation for an individual receiving customer account after a monthly credit allocation shall be carried over to the next month within the annualized period. If an individual receiving customer account holds credits at the end of an annualized period, the account shall be trued up consistent with current net metering practice, with excess kWh compensated at the average annual LMP in the Company's transmission zone.

Remote Net Metering customers shall be responsible for all interconnection costs as described in Section 12.01

Section 12 – Net Metering Installations

12.05 Installation Standards: A Customer-generator shall comply with the requirements of the Company which are set forth in detail in the Application/Agreement Parts 1 and 2 for Level 1 Projects or the Interconnection Application and Agreement for Level 2 or Level 3 Projects both of which are approved by the New Jersey Office of Clean Energy and available at www.firstenergycorp.com. In addition, the Customer-generator shall be responsible for meeting all applicable safety and power quality standards as set forth below.

The Customer-generator's facility shall comply with all applicable safety and power quality standards specified by the National Electrical Code, Institute of Electrical and Electronics Engineers, and accredited testing institutions, such as Underwriters Laboratories. The Customer-generator's facility should be constructed and installed in accordance with the State of New Jersey Uniform Construction Code requirements for electrical installations, UL 1741 and the IEEE Standard 1547. Net Metering systems served by network distribution systems, shall comply with standards established by the Company and approved by the BPU in addition to the aforementioned applicable safety and power quality standards and all other requirements in NJAC 14:8-5.2 et seq

12.06 Initiation of Service: Prior to interconnecting with the Company's distribution system the Customer-generator is required to provide the Company with an Interconnection Application/Agreement Parts 1 and 2 for Level 1 projects or an Interconnection Application and Agreement for Level 2 or Level 3 Projects and must also pay all appropriate charges as detailed in these applications. Additionally, the Company may, at its option, inspect the interconnection prior to the initiation of Net Metering service.

Initiation of service will become effective on the Customer-generator's first regularly scheduled meter reading date that is at least twenty (20) days after the Customer-generator elects to take service under or to be billed under or in accordance with this provision, by executing an Interconnection Application, but in no case prior to the installation of the necessary meter(s), and shall terminate at a regularly scheduled meter reading date that is at least twenty (20) days following the receipt by the Company of Customer-generator's notification of termination or from the date that the Company determines that the customer-generator is no longer eligible for net metering service pursuant to NJAC 14:8-4.1 et seq.

12.07 Net Metering Billing: In any Billing Month during an Annualized period, where the amount of electricity delivered by the Customer-generator plus any kilowatt-hour credits held over from the previous Billing Month or Billing Months exceeds the electricity supplied by the Customer-generator's electric supplier or basic generation service provider, as applicable, the excess kilowatt-hours shall be credited to the Customer-generator in the next Billing Month during the Annualized period. At the end of the Annualized period, the Customer-generator will be compensated for any remaining credits by the Customer-generator's electric supplier or basic generation service provider, as applicable, at the avoided cost of wholesale power (as defined at NJAC 14:8-4.2).

A Customer-generator shall have a one-time opportunity to select a Billing Month as the start of the Customer-generator's Annualized period. This selection will become effective on the first regularly scheduled meter reading date that is at least twenty (20) days after the Customer-generator notifies the Company of the Customer-generator's selection under the one-time opportunity provided in NJAC 14:8-4.3 (f) – (j).

In the event that a Customer-generator changes suppliers, the electric power supplier or basic generation service provider with whom service is terminating shall treat the end of the service period as if it were the end of the Annualized period and shall compensate the Customer-generator for any remaining credits at the avoided cost of wholesale power.

12.08 Program Availability: The Company may be authorized by the BPU to cease offering net metering whenever the total rated generating capacity owned and operated by Customer-generators on a Statewide basis equals 5.8 percent of total annual kilowatt-hour sales in the State.

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Section 13 – Community Solar Energy Pilot Program

13.01 General:

The Community Solar Energy Pilot Program is open to customers of all rate classes who subscribe to community solar projects that are approved by the BPU. Community solar projects and customer subscribers to those approved projects must meet the following minimum requirements, and the full requirements defined in N.J.A.C. 14:8-9.1, *et seq.*, in accordance with N.J.S.A. 48:3-87.11. The program provides for the participation of customers of the Company in all rate classes as subscribers to BPU-approved community solar projects that are located within the service territory of the Company, but may be remotely located from the subscriber's electric service address, and receive a credit on their utility bills in accordance with their participation share. Existing solar projects may not apply to requalify as a Community Solar Energy Pilot Program project. The Pilot Program shall run for a period of no more than 36 months, divided into Program Year 1 (PY1), Program Year 2 (PY2), and Program Year 3 (PY3). PY1 shall begin February 19, 2019, and last until December 31, 2019. Subsequent program years shall begin on January 1 and last for the full calendar year. For each of the three program years, BPU staff shall initiate an annual application process. The annual capacity limit in the Company's service territory each year shall be calculated by the BPU by multiplying the Company's percentage of in-State retail electric sales by the total statewide capacity approved for that year. In PY1, this represented approximately 20.625 MW based upon the Company's 27.5% share of the 75 MW available statewide capacity. Any unallocated capacity at the end of a program year may be reallocated to subsequent program years. At least 40 percent of the annual capacity limit shall be allocated to low and moderate income community (LMI) solar projects. The application and criteria for selection of community solar projects is managed by the BPU. Only projects that are selected by the BPU will be eligible to participate in the Pilot Program. The capacity limit for individual community solar pilot projects is set at a maximum of five MWs per project, measured as the sum of the nameplate capacity in DC rating of all PV panels comprising the community solar facility. The minimum number of participating subscribers for each community solar project shall be set at 10 subscribers and the maximum number of participating subscribers for each community solar project shall be set at 250 subscribers per one MW installed capacity (prorated to project capacity). Each community solar project must be equipped with at least one utility grade meter to facilitate the recording of solar generation underlying the bill credit process.

13.02 Selected Definitions (N.J.A.C. 14:8-9.2):

"Community solar pilot project," "community solar project," or "project" refers to a community solar project approved by the BPU for participation in the Pilot Program, including, but not limited to, the community solar facility, project participants, and subscribers.

"Community solar subscriber organization" or "subscriber organization" means the entity, duly registered with the BPU that works to acquire original subscribers for the community solar project and/or acquires replacement subscribers over the lifetime of the community solar project and/or manages subscriptions for a community solar project. The community solar subscriber organization may or may not be, in whole, in part, or not at all, organized by the community solar developer, community solar owner, or community solar operator.

"Community solar subscriber" or "subscriber" refers to any person or entity who participates in a community solar project by means of the purchase or payment for a portion of the capacity and/or energy produced by a community solar facility. One electric meter denotes one subscriber.

"Community solar subscription" or "subscription" refers to an agreement to participate in a community solar project, by which the subscriber receives a bill credit for a portion of the community solar capacity and/or energy produced by a community solar facility. A subscription may be measured as capacity in kW and/or energy in kWh, ownership of a panel or panels in a community solar facility, ownership of a share of a community solar project, or a fixed and/or variable monthly payment to the project operator.

Section 13 – Community Solar Energy Pilot Program

13.03 Subscription Requirements:

Community solar pilot project subscriptions shall not exceed 100 percent of the subscriber's historic annual usage, calculated over the past 12 months, available at the time of the application. In cases where a 12-month history is not available, the community solar subscriber organization shall estimate, in a commercially reasonable manner, a subscriber's load based on available history. No single subscriber shall subscribe to more than 40 percent of a community solar project's total annual net energy. Subscriptions are portable, provided that the subscriber remains within the original Company service territory as the community solar pilot project to which they are subscribed. Appropriate notice of the change in residence and/or location must be provided to the Company, no later than 30 days after the effective date of the change in residence and/or location. In cases of relocation, subscribers are entitled to one revision per move to their subscription size to account for a change in average consumption. Subscriptions may be sold or transferred back to the project owner or community solar subscriber organization by subscribers as specified in their subscription agreements. Subscribers may not sell or transfer a subscription to another party other than the project owner or community solar subscriber organization. A subscriber may not participate in more than one community solar project. It is the responsibility of the subscriber organization to verify that their subscribers are not already subscribed to another community solar project. The Company shall establish, in coordination with BPU staff, a standardized process by which community solar subscriber organizations can submit on a monthly basis the list of subscribers for a community solar project, and their respective participation shares. The Company shall apply the community solar bill credit to subscribers' utility bills in proportion to each subscriber's participation share, in conformance with the bill credit calculation method described below.

13.04 Community Solar Bill Credits

Participating subscriber customers will receive a dollar-based bill credit for their subscribed percentage of the monthly kilowatt-hour output of the community solar project in proportion to the subscriber's share of the community solar project as indicated on the most recent list received from the subscriber organization. The monthly dollar credit on the subscriber's bill will be the equivalent of their subscription percentage of the community solar project monthly kilowatt-hour generation amount applied to all kilowatt-hour charges on the subscriber's bill, excluding all fixed and non-by-passable charges and SUT. The non-bypassable charges are the fixed monthly customer charge, all kW demand charges (if applicable), the SBC charge, the NGC charge and the ZEC charge. The value of the bill credit shall be set at the weighted class average retail rate for their respective service classification. The bill credit for CIEP eligible customers will be set at the average hourly energy price. Customers served by a third-party supplier will have their credit based upon the BGS rate. The subscriber's bill credit will be used to offset the subscriber's total bill up to the amount of actual metered consumption. The calculation of the value of the bill credit shall remain as described above and shall remain in effect for the life of the project, defined as no more than 20 years from the date of commercial operation of the project or the period until the project is decommissioned, whichever comes first, in addition to any modifications subsequently ordered by the BPU. The community solar bill credit will be specifically identified as the community solar bill credit in a separate line on the subscribers' utility bills.

Section 13 – Community Solar Energy Pilot Program

13.04 Community Solar Bill Credits (Continued)

An annualized period shall be established for each subscriber. The annualized period shall begin on the day a subscriber first earns a community solar bill credit based on the delivery of energy, and continues for a period of 12 months, until the subscription ends, or until the subscriber's Company account is closed, whichever occurs earlier. The Company may sync up the monthly billing period of subscribers and projects, by modifying, with due notice given, the monthly billing period for subscribers upon their first month of participation in the community solar project. Excess credits above the level of the metered monthly consumption shall carry over from monthly billing period to monthly billing period, with the balance of credits accumulating until the earlier of either the end of the annualized period, the closure of the subscriber's Company account, or the end of the subscriber's community solar subscription. At the end of the annualized period and/or when a subscriber's Company account is closed and/or at the end of the subscriber's community solar subscription, any excess net bill credits greater than the sum of all appropriate billable charges shall be compensated at the Company's average LMP of the JCP&L transmission zone. The excess compensation must be returned to the subscriber by bill credit, wire transfer, or check. If a subscriber receives net excess credits for each of the three previous consecutive years, the subscriber organization must resize the subscriber's subscription size to ensure it does not exceed 100 percent of historic annual usage, calculated over the past 12 months, available at the time of the reassessment.

Any generation delivered to the grid that has not been allocated to a subscriber may be "banked" by the project operator in a dedicated project Company account for an annualized period of up to 12 months. The banked credits may be distributed by the project operator to any new or existing subscriber during that 12-month period, in conformance with subscription requirements set forth in N.J.A.C. 14:8-9.6. At the end of the up to 12-month period, any remaining generation credits shall be compensated at the Company's average LMP of the JCP&L transmission zone. Subscribers must have an active electric account within the Company's service territory of the community solar project to which they are subscribed. Upon Company request, If required by the Company, subscribers must agree to a remote read smart meter upon EDC request, purchased and installed at EDC cost.

The Company will utilize a standardized process for sharing subscriber information between subscriber organizations and the Company by which subscriber organizations can submit the lists of subscribers. Subscriber organizations shall send to the Company a list of subscribers to the project with all appropriate subscriber information, no later than 60 days prior to the first monthly billing period for the community solar project. Additionally, subscriber organizations shall send an updated list to the Company once per month.

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 13 ELECTRIC - PART II Original Sheet No. 44

Appendix A - Unit Costs of Underground Construction
Single Family Developments

Appendix A - Residential Electric Underground Extensions
The Applicant shall pay the Company the amount determined from the following table:

A. Base Charges

1. Single Family	Average Front Footage Per Lot <= 125 Ft	126-225 Ft	226-325 Ft	>= 326Ft
Nonrefundable charge per building lot				
• With Applicant providing all trenching and road crossing conduits	$ 361.00	$ 428.00	$ 495.00	$ 881.00
Refundable deposit based on equivalent overhead construction	$ 828.00	$1,656.00	$2,484.00	$4,140.00

2. Lots requiring 1Φ primary extension
   Without primary enclosure $1,532.00
   With primary enclosure $4,236.44

3. Duplex-family buildings, mobile homes, multiple occupancy buildings, three-phase high capacity extensions, lots requiring primary extensions thereon, excess transformer capacity above 8.5 KVA, etc. — Charge to be based on differential cost according to unit costs specified in Exhibits I through III

B. Additional Charges

1. Street Lights - SVL
   16 foot fiberglass pole with standard colonial post top luminaire ..... $ 365.00
   16 foot fiberglass pole with ornate colonial post top luminaire $1,026.00
   30 foot fiberglass pole with cobra head luminaire on 6 foot bracket $1,126.00
   12 foot 9 inch ornate fiberglass pole with ornate colonial post top luminaire $2,567.00
   12 foot 9 inch ornate fiberglass pole with acorn style post top luminaire - LED $3,234.00
   16 foot Fiberglass pole with colonial post top luminaire……$ 577.00
   30 foot fiberglass pole with Cobra Head……$1,164.00
   12 foot 9 inch ornate fiberglass pole with acorn style post top luminaire……$2,118.00

2. Multi-Phase Construction $1.28 per added phase per foot

3. Pavement cutting and restoration, rock removal, blasting, difficult digging, and special backfill — At actual low bid cost with option of Applicant to contract for as limited by NJAC

Note: All charges are subject to taxes as provided in Section 3.14.

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 13 ELECTRIC - PART II Original Sheet No. 45

Appendix A - Exhibit I - Unit Costs of Underground Construction Single-Phase 15 kV

	Item	Unit	Total Cost
1.	Primary cable 1/0 aluminum	per foot	$ 3.86
2.	Secondary cable 3/0 aluminum	per foot	2.48
	350 MCM aluminum	per foot	5.02
	500 MCM aluminum	per foot	8.09
	750 MCM aluminum	per foot	11.04
3.	Service - 200 amp and below	per foot	2.48
	50 feet complete	each	614.14
4.	Primary termination - branch	each	1,372.50
5.	Primary junction enclosure - branch	each	2,703.80
6.	Secondary enclosure	each	646.61
7.	Conduit - 3 inch PVC	per foot	3.94
	Conduit - 4 inch PVC	per foot	4.75
8.	Street light cable - # 12 cu. duplex	per foot	2.93
9.	Transformers - including fiberglass pad		
	25 kVa – single-phase	each	2,616.27
	50 kVa – single-phase	each	2,921.40
	75 kVa – single-phase	each	3,305.99
	100 kVa – single-phase	each	3,680.90
	167 kVa – single-phase	each	4,386.08
	25 kVa – single-phase Dual Voltage	each	3,035.23
	50 kVa – single-phase Dual Voltage	each	3,299.85
	75 kVa – single-phase Dual Voltage	each	4,093.62
10.	Street light poles		
	16 foot post top fiberglass pole	each	576.58
	30 foot fiberglass pole	each	1,163.74
	12 foot 9 inch ornate fiberglass pole	each	2,117.95
11.	Street light luminaire – cobra head SVL	each	539.26
12.	Post top luminaire – SVL		
	50, 70, 100 & 150 watt colonial style	each	365.76
	70 & 100 watt ornate colonial style	each	1,026.42
	70 & 100 watt ornate acorn style	each	1,693.36
13.	Primary splice – # 2 aluminum	each	188.84

Note: All charges are subject to taxes as provided in Section 3.14.

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 13 ELECTRIC - PART II Original Sheet No. 46

Appendix A - Exhibit II - Unit Costs of Underground Construction Three-Phase 15 kV

	Item	Unit	Total Cost
1.	Primary cable – three-phase main feeder	per foot	$ 24.93
2.	Secondary cable - 4-wire 350 MCM aluminum	per foot	8.60
3.	Service cable - 4-wire 350 MCM aluminum	per foot	8.92
4.	Primary termination - main		
	# 2 aluminum three-phase	each	3,365.54
	1000 MCM aluminum three-phase	each	4,961.19
5.	Primary junction - main	each	4,660.04
6.	Primary switch - main		
	PMH-9	each	34,679.04
	PMH-10	each	30,136.80
	PMH-11	each	31,658.44
	PMH-12	each	38,639.32
7.	Conduit - 5 inch PVC	per foot	5.98
	- 6 inch PVC	per foot	7.40
8.	Transformers - including concrete pad		
	75 kVa three-phase	each	6,297.08
	150 kVa three-phase	each	6,980.84
	300 kVa three-phase	each	8,835.18
	500 kVa three-phase	each	10,988.05
9.	Primary splice – 15 kV three-phase cable	each	433.75

Note: All charges are subject to taxes as provided in Section 3.14.

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 13 ELECTRIC - PART II Original Sheet No. 47

Appendix A - Exhibit III - Unit Costs of Overhead Construction Single and Three-Phase 15 kV

	Item	Unit	Total Cost
1.	Pole line (including 40 foot poles, anchors & guys)	per foot	$ 6.56*
2.	Primary wire		
	Single-phase – branch	per foot	2.58
	Three-phase – main	per foot	12.08
3.	Primary wire - neutral	per foot	2.42
4.	Secondary cable		
	Three-wire	per foot	5.16
	Four-wire	per foot	8.45
5.	Service		
	Single-phase	each	244.60
	Single–phase - 200 amp and below	per foot	2.49
	Three-phase – up to 200 amp	per foot	4.02
	Three-phase – over 200 amp	per foot	6.67
6.	Transformers		
	25 kVa – single-phase	each	1,453.17
	50 kVa – single-phase	each	1,763.05
	75 kVa – single-phase	each	2,273.13
	100 kVa – single-phase	each	2,635.99
	167 kVa – single-phase	each	3,073.14
	3- 25 kVa – three-phase	each	3,818.97
	3- 50 kVa – three-phase	each	4,748.61
	3- 75 kVa – three-phase	each	6,404.91
	3-100 kVa – three-phase	each	7,481.49
	3-167 kVa – three-phase	each	8,792.94
7.	Street light luminaire – cobra head SVL	each	577.38

Pole line cost to be used = $6.56 / 2 = $3.28

Note: All charges are subject to taxes as provided in Section 3.14.

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 13 ELECTRIC - PART II Original Sheet No. 48

Appendix A - Exhibit III - Unit Costs of Overhead Construction Single and Three-Phase 15 kV

Item	Unit	Total Cost
8. Street light luminaire – LED – Contributions		
Monthly Contribution Fixture charge of $2.65		
30 W Cobra Head	each	$ 358.38
50 W Cobra Head	each	354.88
90 W Cobra Head	each	403.55
130 W Cobra Head	each	492.97
260 W Cobra Head	each	694.22
50 W Acorn	each	1,295.80
90 W Acorn	each	1,243.30
50 W Colonial	each	619.38
90 W Colonial	each	793.88
Monthly Contribution Fixture charge of $4.24		
30 W Cobra Head	each	209.20
50 W Cobra Head	each	205.70
90 W Cobra Head	each	254.37
130 W Cobra Head	each	343.79
260 W Cobra Head	each	545.04
50 W Acorn	each	1,146.62
90 W Acorn	each	1,094.12
50 W Colonial	each	470.20
90 W Colonial	each	644.70

Note: All charges are subject to taxes as provided in Section 3.14.

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU NO. 13 ELECTRIC ORIGINAL TITLE SHEET

TARIFF for SERVICE

Part III

Service Classifications and Riders

Issued: October 30, 2020 **Effective: December 1, 2020**

Filed pursuant to Order of Board of Public Utilities
Docket Nos. ER20020146 and PUC 04343-2020N dated October 28, 2020

Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 13 ELECTRIC - PART III

7th Rev. Sheet No. 1
Superseding 6th Rev. Sheet No. 1

PART III
SERVICE CLASSIFICATIONS AND RIDERS
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JERSEY CENTRAL POWER & LIGHT COMPANY

38th Rev. Sheet No. 2
BPU No. 13 ELECTRIC - PART III — Superseding 37th Rev. Sheet No. 2

PART III
SERVICE CLASSIFICATIONS AND RIDERS
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JERSEY CENTRAL POWER & LIGHT COMPANY

5th Rev. Sheet No. 3
BPU No. 13 ELECTRIC - PART III — Superseding 4th Rev. Sheet No. 3

Service Classification RS
Residential Service

APPLICABLE TO USE OF SERVICE FOR: Service Classification RS is available for: (a) Individual Residential Structures; (b) separately metered residences in Multiple Residential Structures; (c) incidental use for non-residential purposes when included along with the residence; and/or (d) Auxiliary Residential Purposes whether metered separately from the residence or not.

This Service Classification is optional for customers which elect to be billed hereunder rather than under Service Classification RT. (Also see Part II, Section 2.03)

CHARACTER OF SERVICE: Single-phase service, with limited applications of three-phase service, at secondary voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)

2) **Transmission Charge: $0.010056** per KWH for all KWH including Water Heating

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge: $ 3.25** per month
Supplemental Customer Charge: $ 1.70 per month Off-Peak/Controlled Water Heating

2) **Distribution Charge:**

June through September:
$0.017927 per KWH for the first 600 KWH (except Water Heating)
$0.070892 per KWH for all KWH over 600 KWH (except Water Heating)

October through May:
$0.029367 per KWH for all KWH (except Water Heating)

Water Heating Service:
$0.019600 per KWH for all KWH for Off-Peak Water Heating
$0.025816 per KWH for all KWH for Controlled Water Heating

Service Classification RS
Residential Service

3) **Non-utility Generation Charge (Rider NGC): (See Rider NGC for any applicable St. Lawrence Hydroelectric Power credit)**
See Rider NGC for rate per KWH for all KWH including Off-Peak/Controlled Water Heating

4) **Societal Benefits Charge (Rider SBC):**
See Rider SBC for rate per KWH for all KWH including Off-Peak/Controlled Water Heating

5) **RGGI Recovery Charge (Rider RRC):**
See Rider RRC for rate per KWH for all KWH including Off-Peak/Controlled Water Heating

6) **Zero Emission Certificate Recovery Charge (Rider ZEC):**
See Rider ZEC for rate per KWH for all KWH including Off-Peak/Controlled Water Heating

7) **Tax Act Adjustment (Rider TAA):**
See Rider TAA for rate per KWH for all KWH including Off-Peak/Controlled Water Heating

8) **JCP&L Reliability Plus Charge (Rider RP):**
See Rider RP for rate per KWH for all KWH including Off-Peak/Controlled Water Heating

9) **JCP&L Lost Revenue Adjustment Mechanism Charge (Rider LRAM):**
See Rider LRAM for rate per KWH for all KWH including Off-Peak/Controlled Water Heating

10) **Electric Vehicle Charger Rider (Rider EV):**
See Rider EV for information about the EV Driven Program

TERM OF CONTRACT: None, except that reasonable notice of service discontinuance will be required. Where special circumstances apply or special or unusual facilities are supplied, a contract of one year or more may be required.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill.

SERVICE CHARGE: A Service Charge of **$14.00** shall be applicable for initiating service to a customer under any Service Classification (see Part II, Section 2.01). A **$54.00** Service Charge shall be applicable for final bill readings requested to be performed other than during the normal working hours of 8 AM to 4:30 PM, Monday through Friday. (See Part II, Section 3.13)

RECONNECTION CHARGES: A Reconnection Charge, applicable after a discontinuance requested by the customer or because of a default by the customer, of **$45.00** is applicable to service reconnections which can be performed at the meter. The charge for all reconnections which cannot be performed at the meter shall be based upon the costs incurred by the Company. (See Part II, Section 7.04)

DELINQUENT CHARGE: A Field Collection Charge of **$25.00** shall be applicable for each collection visit made to the customer's premises. (See Part II, Section 3.20)

Service Classification RS
Residential Service

SPECIAL PROVISIONS:

(a) Restricted Off-Peak Water Heating Service: Locations currently receiving service under this Special Provision which have automatic storage-type water heaters for the supply of hot water requirements of the premises, where such water heaters comply with and are installed in accordance with Company specifications, shall be billed a Supplemental Customer Charge, and shall have the KWH used during the off-peak hours of 8 PM to 8 AM Eastern Standard Time measured by a separate meter and billed at the Charges provided above. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change. (Also see Part II, Section 5.09)

(b) Restricted Controlled Water Heating Service: Locations currently receiving service under this Special Provision which have automatic storage-type water heaters for the supply of hot water requirements of the premises, where such water heaters comply with and are installed in accordance with Company specifications and have the operation of both upper and lower elements restricted by Company control devices to the hours of 11 PM to 4 PM Eastern Standard Time, shall be billed a Supplemental Customer Charge, and shall have the KWH used during those hours measured by a separate meter and billed at the Charges provided above. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change. (Also see Part II, Section 5.10)

ADDITIONAL MODIFYING RIDER: This Service Classification may also be modified for other Rider(s) subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

Service Classification RT
Residential Time-of-Day Service

APPLICABLE TO USE OF SERVICE FOR: Service Classification RT is available for: (a) Individual Residential Structures; (b) separately metered residences in Multiple Residential Structures; (c) incidental use for non-residential purposes when included along with the residence; and/or (d) Auxiliary Residential Purposes whether metered separately from the residence or not.

This Service Classification is optional for customers which elect to be billed hereunder rather than under Service Classification RS. (Also see Part II, Section 2.03)

CHARACTER OF SERVICE: Single-phase service, with limited applications of three-phase service, at secondary voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)

2) **Transmission Charge: $0.010056** per KWH for all KWH on-peak and off-peak

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge: $ 7.05** per month
Solar Water Heating Credit: $ 1.77 per month

2) **Distribution Charge:**
$0.052349 per KWH for all KWH on-peak for June through September
$0.038452 per KWH for all KWH on-peak for October through May
$0.024453 per KWH for all KWH off-peak

3) **Non-utility Generation Charge (Rider NGC): (See Rider NGC for any applicable St. Lawrence Hydroelectric Power credit)**
See Rider NGC for rate per KWH for all KWH on-peak and off-peak

4) **Societal Benefits Charge (Rider SBC):**
See Rider SBC for rate per KWH for all KWH on-peak and off-peak

5) **RGGI Recovery Charge (Rider RRC):**
See Rider RRC for rate per KWH for all KWH on-peak and off-peak

6) **Zero Emission Certificate Recovery Charge (Rider ZEC):**
See Rider ZEC for rate per KWH for all KWH on-peak and off-peak

7) **Tax Act Adjustment (Rider TAA):**
See Rider TAA for rate per KWH for all KWH on-peak and off-peak

8) **JCP&L Reliability Plus Charge (Rider RP):**
See Rider RP for rate per KWH for all KWH on-peak and off-peak

9) **JCP&L Lost Revenue Adjustment Mechanism Charge (Rider LRAM):**
See Rider LRAM for rate per KWH for all KWH on-peak and off-peak

10) **Electric Vehicle Charger Rider (Rider EV):**
See Rider EV for information about the EV Driven Program

Service Classification RT
Residential Time-of-Day Service

DEFINITION OF ON-PEAK AND OFF-PEAK HOURS: The hours to be considered as on-peak are from 8 AM to 8 PM Eastern Standard Time, Monday through Friday. All other hours including weekend hours will be considered off-peak. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change. The Company may also selectively stagger the on-peak hours up to one hour in either direction when required to alleviate local distribution system peaking within high density areas. The off-peak hours will not, however, be less than 12 hours daily.

TERM OF CONTRACT: None, except that reasonable notice of service discontinuance will be required. Where special circumstances apply or special or unusual facilities are supplied, contracts of one year or more may be required.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill.

SERVICE CHARGE: A Service Charge of **$14.00** shall be applicable for initiating service to a customer under any Service Classification (see Part II, Section 2.01). A **$54.00** Service Charge shall be applicable for final bill readings requested to be performed other than during the normal working hours of 8 AM to 4:30 PM, Monday through Friday. (See Part II, Section 3.13)

RECONNECTION CHARGES: A Reconnection Charge, applicable after a discontinuance requested by the customer or because of a default by the customer, of **$45.00** is applicable to service reconnections which can be performed at the meter. The charge for all reconnections which cannot be performed at the meter shall be based upon the costs incurred by the Company. (See Part II, Section 7.04)

DELINQUENT CHARGE: A Field Collection Charge of **$25.00** shall be applicable for each collection visit made to the customer's premises. (See Part II, Section 3.20)

SPECIAL PROVISION: Solar Water Heating Systems: For customers who install a solar water heating system with electric backup, the monthly Customer Charge shall be reduced by the credit provided above.

ADDITIONAL MODIFYING RIDER: This Service Classification may also be modified for other Rider(s), subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

JERSEY CENTRAL POWER & LIGHT COMPANY

5th Rev. Sheet No. 8
BPU No. 13 ELECTRIC - PART III Superseding 4th Rev. Sheet No. 8

Service Classification RGT
Residential Geothermal & Heat Pump Service

APPLICABLE TO USE OF SERVICE FOR: Service Classification RGT is available for residential customers residing in individual residential structures, or in separately metered residences in multiple-unit residential structures, who have one of the following types of electric space heating systems as the primary source of heat for such structure or unit and which system meets the corresponding energy efficiency criterion:

Geothermal Systems with Energy Efficiency Ratio (EER) of 13.0 or greater;
Heat Pump Systems with Seasonal Energy Efficiency Ratio (SEER) of 11.0 or greater, and a Heating Season Performance Factor (HSPF) which meets the then current Federal HSPF standards;
Room Unit Heat Pump Systems with Energy Efficiency Ratio (EER) of 9.5 or greater.

Service Classification RGT is not available for customers residing in individual residential structures, or in separately metered residences in multiple-unit residential structures, which have an electric resistance heating system as the primary source of space heating for such structure or unit.

CHARACTER OF SERVICE: Single-phase service, with limited applications of three-phase service, at secondary voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)

2) **Transmission Charge:**
$0.010056 per KWH for all KWH on-peak and off-peak for June through September
$0.010056 per KWH for all KWH for October through May

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge: $ 7.05** per month

2) **Distribution Charge:**

June through September:
$0.052349 per KWH for all KWH on-peak
$0.024453 per KWH for all KWH off-peak

October through May:
$0.029367 per KWH for all KWH

Service Classification RGT
Residential Geothermal & Heat Pump Service

3) **Non-utility Generation Charge (Rider NGC): (See Rider NGC for any applicable St. Lawrence Hydroelectric Power credit)**
See Rider NGC per KWH for all KWH on-peak and off-peak

4) **Societal Benefits Charge (Rider SBC):**
See Rider SBC per KWH for all KWH on-peak and off-peak

5) **RGGI Recovery Charge (Rider RRC):**
See Rider RRC for rate per KWH for all KWH on-peak and off-peak

6) **Zero Emission Certificate Recovery Charge (Rider ZEC):**
See Rider ZEC for rate per KWH for all KWH on-peak and off-peak

7) **Tax Act Adjustment (Rider TAA):**
See Rider TAA for rate per KWH for all KWH on-peak and off-peak

8) **JCP&L Reliability Plus Charge (Rider RP):**
See Rider RP for rate per KWH for all KWH on-peak and off-peak

9) **JCP&L Lost Revenue Adjustment Mechanism Charge (Rider LRAM):**
See Rider LRAM for rate per KWH for all KWH on-peak and off-peak

10) **Electric Vehicle Charger Rider (Rider EV):**
See Rider EV for information about the EV Driven Program

DEFINITION OF ON-PEAK AND OFF-PEAK HOURS: The hours to be considered as on-peak are from 8 AM to 8 PM Eastern Standard Time, Monday through Friday. All other hours including weekend hours will be considered off-peak. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change. The Company may also selectively stagger the on-peak hours up to one hour in either direction when required to alleviate local distribution system peaking within high-density areas. The off-peak hours will not, however, be less than 12 hours daily.

TERM OF CONTRACT: None, except that reasonable notice of service discontinuance will be required. Where special circumstances apply or special or unusual facilities are supplied, contracts of one year or more may be required.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill.

SERVICE CHARGE: A Service Charge of **$14.00** shall be applicable for initiating service to a customer under any Service Classification (see Part II, Section 2.01). A **$54.00** Service Charge shall be applicable for final bill readings requested to be performed other than during the normal working hours of 8 AM to 4:30 PM, Monday through Friday. (See Part II, Section 3.13)

RECONNECTION CHARGES: A Reconnection Charge, applicable after a discontinuance requested by the customer or because of a default by the customer, of **$45.00** is applicable to service reconnections which can be performed at the meter. The charge for all reconnections which cannot be performed at the meter shall be based upon the costs incurred by the Company. (See Part II, Section 7.04)

DELINQUENT CHARGE: A Field Collection Charge of **$25.00** shall be applicable for each collection visit made to the customer's premises. (See Part II, Section 3.20)

ADDITIONAL MODIFYING RIDER: This Service Classification may also be modified for other Rider(s), subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

5th Rev. Sheet No. 10
BPU No. 13 ELECTRIC - PART III Superseding 4th Rev. Sheet No. 10

Service Classification GS
General Service Secondary

APPLICABLE TO USE OF SERVICE FOR: Service Classification GS is available for general service purposes at secondary voltages not included under Service Classifications RS, RT, RGT or GST.

CHARACTER OF SERVICE: Single or three-phase service at secondary voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly BGS-FP) **or Rider BGS-CIEP (Basic Generation Service – Commercial Industrial Energy Pricing)**

2) **Transmission Charge:**
$0.010056 per KWH for all KWH including Water Heating

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge:** **$ 4.09** per month single-phase
$14.69 per month three-phase

Supplemental Customer Charge: **$ 1.70** per month Off-Peak/Controlled Water Heating
$ 3.35 per month Day/Night Service
$15.27 per month Traffic Signal Service

2) **Distribution Charge:**

KW Charge: (Demand Charge)
$ 7.92 per maximum KW during June through September, in excess of 10 KW
$ 7.38 per maximum KW during October through May, in excess of 10 KW
$ 3.59 per KW Minimum Charge, in excess of 10 KW

Service Classification GS
General Service Secondary

KWH Charge:
June through September (excluding Water Heating and Traffic Signal Service):
$0.066358 per KWH for all KWH up to 1000 KWH
$0.005307 per KWH for all KWH over 1000 KWH

October through May (excluding Water Heating and Traffic Signal Service):
$0.061400 per KWH for all KWH up to 1000 KWH
$0.005307 per KWH for all KWH over 1000 KWH

Water Heating Service:
$0.019600 per KWH for all KWH Off-Peak Water Heating
$0.025816 per KWH for all KWH Controlled Water Heating

Traffic Signal Service:
$0.013906 per KWH for all KWH

Religious House of Worship Credit:
$0.033830 per KWH for all KWH up to 1000 KWH

3) **Non-utility Generation Charge (Rider NGC):**
See Rider NGC for rate per KWH for all KWH (including Off-Peak/Controlled Water Heating and Traffic Signal Service)

4) **Societal Benefits Charge (Rider SBC):**
See Rider SBC for rate per KWH for all KWH (including Off-Peak/Controlled Water Heating and Traffic Signal Service)

5) **CIEP – Standby Fee as provided in Rider CIEP – Standby Fee** (formerly Rider DSSAC)

6) **RGGI Recovery Charge (Rider RRC):**
See Rider RRC for rate per KWH for all KWH (including Off-Peak/Controlled Water Heating and Traffic Signal Service)

7) **Zero Emission Certificate Recovery Charge (Rider ZEC):**
See Rider ZEC for rate per KWH for all KWH (including Off-Peak/Controlled Water Heating and Traffic Signal Service)

8) **Tax Act Adjustment (Rider TAA):**
See Rider TAA for rate per KWH for all KWH (including Off-Peak/Controlled Water Heating and Traffic Signal Service)

9) **JCP&L Reliability Plus Charge (Rider RP):**
See Rider RP for rate per KWH for all KWH (including Off-Peak/Controlled Water Heating and traffic Signal Service)

10) **JCP&L Lost Revenue Adjustment Mechanism Charge (Rider LRAM):**
See Rider LRAM for rate per KWH for all KWH (including Off-Peak/Controlled Water Heating and traffic Signal Service)

11) Electric Vehicle Charger Rider (Rider EV):
See Rider EV for information about the EV Driven Program

MINIMUM DEMAND CHARGE PER MONTH: The monthly KW Demand Charge under Distribution Charge shall be the greater of (1) the product of the KW Charge per maximum KW provided above and the current month's maximum demand created during on-peak hours as determined below; or (2) the product of the KW Minimum Charge provided above and the highest on-peak or off-peak demand created in the current and preceding eleven months (but not less than the Contract Demand).

Service Classification GS
General Service Secondary

DETERMINATION OF DEMAND: The KW used for billing purposes shall be the maximum 15-minute integrated kilowatt demand during each billing month calculated to the nearest one-tenth KW. In instances where the Company has determined that the demand will not exceed 10 KW, and has therefore elected to not install a demand meter, the demand shall be considered less than 10 KW for billing purposes. Where Service is rendered under Special Provision (a), the on-peak demand shall be the maximum 15-minute integrated kilowatt demand created during the on-peak hours of 8 AM to 8 PM prevailing time, Monday through Friday each billing month, while the off-peak demand shall be the maximum demand created during the remaining hours. A Contract Demand not less than the actual monthly demands may also be specified for mutually agreeable contract purposes.

TERM OF CONTRACT: None, except that reasonable notice of service discontinuance will be required. Where special circumstances apply or special or unusual facilities are supplied by the Company, a contract of one year or more to supply such facilities or accommodate special circumstances may be required for any Full Service Customer and any Delivery Service Customer.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill. Overdue bills thereafter become subject to a late payment charge as described in Section 3.19, Part II.

SERVICE CHARGE: A Service Charge of **$14.00** shall be applicable for initiating service to a customer under any Service Classification (see Part II, Section 2.01). A **$54.00** Service Charge shall be applicable for final bill readings requested to be performed other than during the normal working hours of 8 AM to 4:30 PM, Monday through Friday. (See Part II, Section 3.13)

RECONNECTION CHARGES: A Reconnection Charge, applicable after a discontinuance requested by the customer or because of a default by the customer, of **$45.00** is applicable to service reconnections which can be performed at the meter. The charge for all reconnections which cannot be performed at the meter shall be based upon the costs incurred by the Company. (See Part II, Section 7.04)

DELINQUENT CHARGE: A Field Collection Charge of **$25.00** shall be applicable for each collection visit made to the customer's premises. (See Part II, Section 3.20)

RECONNECTIONS WITHIN 12-MONTH PERIOD: Customers who request a disconnection and reconnection of service at the same location within a 12-month period shall not be relieved of Minimum Demand Charges resulting from demands created during the preceding eleven months, even though occurring prior to such disconnection.

Customers who request more than one disconnection and reconnection of service at the same location within a 12-month period shall be subject to the conditions specified above for the first such period of disconnection. In addition, for subsequent periods of disconnection, the customer shall be required to pay an additional Reconnection Charge equivalent to the sum of the Minimum Demand Charges, determined in accordance with the conditions specified in the preceding paragraph, for each month of that subsequent period.

Service Classification GS
General Service Secondary

SPECIAL PROVISIONS:

(a) Day/Night Service: Customers who normally operate in such manner that their maximum demands do not occur during the Company's on-peak period and elect to receive Service under this Special Provision shall have their monthly demand charge under this Service Classification based upon the greater of: (a) the maximum on-peak demand created during the month; or (b) 40 percent of the maximum off-peak demand created during the month. For the monthly KW Minimum Charge calculation, the Customer's demand will be based on the greater of: (a) the maximum on-peak demand created during the current and preceding eleven months; or (b) 40 percent of the maximum off-peak demand created during the current and preceding eleven months (but not less than the Contract Demand). Customers served under this Special Provision shall be billed an additional Supplemental Customer Charge provided above.

(b) Restricted Commercial and Industrial Space Heating Service: Customers served as of February 6, 1979, who have (1) electricity as the sole primary source of energy for space heating the entire structure(s) as well as for lighting, power, cooking, refrigeration, water heating, and similar purposes except for incidental special applications or purposes where electrical energy cannot reasonably be used; (2) the sum of the connected loads for lighting, space heating, cooking, and water heating exceed 50% of the total connected load; and (3) at least 50% of the total electrical load is located in a structure(s) heated by electricity; shall have the monthly KW Minimum Charge calculation modified such that the Customer's demand will be based on the highest demand established in the summer billing months only.

(c) Traffic Signal Service: Customers receiving service for traffic signal installations shall be billed an additional monthly Supplemental Customer Charge and the KWH Charges provided above.

(d) Restricted Off-Peak Water Heating Service: Locations currently receiving Service under this Special Provision which have automatic storage-type water heaters for the supply of hot water requirements of the premises, where such water heaters comply with and are installed in accordance with Company specifications, shall be billed a Supplemental Customer Charge, and shall have the KWH used during the off-peak hours of 8 PM to 8 AM Eastern Standard Time measured by a separate meter and billed at the Charges provided above. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change. (Also see Part II, Section 5.09)

(e) Restricted Controlled Water Heating Service: Locations currently receiving Service under this Special Provision which have automatic storage-type water heaters for the supply of hot water requirements of the premises, where such water heaters comply with and are installed in accordance with Company specifications and have the operation of both upper and lower elements restricted by Company control devices to the hours of 11 PM to 4 PM Eastern Standard Time, shall be billed a Supplemental Customer Charge, and shall have the KWH used during those hours measured by a separate meter and billed at the Charges provided above. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change. (Also see Part II, Section 5.10)

(f) Religious Houses of Worship Service: When electric service is supplied to a customer where the primary use of service is for public religious services and the customer applies for and is eligible for such Service, the customer's monthly Distribution Charge will be subject to a KWH Credit provided above for the first 1000 KWH usage per month. The Customer will be required to sign an Application for Religious Houses of Worship Service certifying eligibility. Upon request by Company, the Customer shall furnish satisfactory proof of eligibility for Service under this Special Provision.

ADDITIONAL MODIFYING RIDERS: This Service Classification may also be modified for other Rider(s), subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

Service Classification GS
General Service Secondary

VETERANS' ORGANIZATION SERVICE SPECIAL PROVISION:

Pursuant to N.J.S.A 48:2-21.41, when electric service is delivered to a customer that is a Veterans' Organization, 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 of 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.

The customer will continue to be billed on this Service Classification. At least once annually, the Company shall review eligible customers' delivery service charges under this Special Provision for all relevant periods. If the comparable delivery service charges under Service Classification RS (Residential Service) are lower than the delivery service charges under this Service Classification, a credit in the amount of the difference will be applied to the customer's next bill.

5th Rev. Sheet No. 15
BPU No. 13 ELECTRIC - PART III Superseding 4th Rev. Sheet No. 15

Service Classification GST
General Service Secondary Time-Of-Day

APPLICABLE TO USE OF SERVICE FOR: Service Classification GST is available for general Service purposes for commercial and industrial customers establishing demands in excess of 750 KW in two consecutive months during the current 24-month period. Customers which were served under this Service Classification as part of its previous experimental implementation may continue such Service until voluntarily transferring to Service Classification GS.

CHARACTER OF SERVICE: Single or three-phase service at secondary voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP) **or Rider BGS-CIEP (Basic Generation Service – Commercial Industrial Energy Pricing)**

2) **Transmission Charge:** **$0.010056** per KWH for all KWH on-peak and off-peak

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge:** **$ 35.57** per month single-phase
$ 50.75 per month three-phase

2) **Distribution Charge:**

KW Charge: (Demand Charge)
$ 8.36 per maximum KW during June through September
$ 7.82 per maximum KW during October through May
$ 3.65 per KW Minimum Charge

KWH Charge:
$0.005155 per KWH for all KWH on-peak
$0.005155 per KWH for all KWH off-peak

Service Classification GST
General Service Secondary Time-Of-Day

3) **Non-utility Generation Charge (Rider NGC):**
See Rider NGC for rate per KWH for all KWH on-peak and off-peak

4) **Societal Benefits Charge (Rider SBC)**:
See Rider SBC for rate per KWH for all KWH on-peak and off-peak

5) **CIEP – Standby Fee as provided in Rider CIEP – Standby Fee** (formerly Rider DSSAC)

6) **RGGI Recovery Charge (Rider RRC):**
See Rider RRC for rate per KWH for all KWH on-peak and off-peak

7) **Zero Emission Certificate Recovery Charge (Rider ZEC):**
See Rider ZEC for rate per KWH for all KWH on-peak and off-peak

8) **Tax Act Adjustment (Rider TAA):**
See Rider TAA for rate per KWH for all KWH on-peak and off-peak

9) **JCP&L Reliability Plus Charge (Rider RP):**
See Rider RP for rate per KW for all KW

10) **JCP&L Lost Revenue Adjustment Mechanism Charge (Rider LRAM):**
See Rider LRAM for rate per KW for all KW

11) **Electric Vehicle Charger Rider (Rider EV):**
See Rider EV for information about the EV Driven Program

MINIMUM DEMAND CHARGE PER MONTH: The monthly KW Demand Charge under Distribution Charge shall be the greater of (1) the product of the KW Charge per maximum KW provided above and the current month's maximum demand created during on-peak hours as determined below; or (2) the product of the KW Minimum Charge provided above and the highest on-peak or off-peak demand created in the current and preceding eleven months (but not less than the Contract Demand).

DETERMINATION OF DEMAND: The KW during on-peak hours used for billing purposes shall be the maximum 15-minute integrated kilowatt demand created during the on-peak hours each billing month calculated to nearest one-tenth KW. The off-peak demand shall be the maximum demand created during the remaining hours. A Contract Demand not less than the actual monthly demands may also be specified for mutually agreeable contract purposes.

DEFINITION OF ON-PEAK AND OFF-PEAK HOURS: The hours to be considered as on-peak are from 8 AM to 8 PM prevailing time Monday through Friday. All other hours including weekend hours will be considered off-peak. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change. The off-peak hours will not be less than 12 hours daily.

TERM OF CONTRACT: None, except that reasonable notice of service discontinuance will be required. Where special circumstances apply or special or unusual facilities are supplied by the Company, a contract of one year or more to supply such facilities or accommodate special circumstances may be required for any Full Service Customer and any Delivery Service Customer.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill. Overdue bills thereafter become subject to a late payment charge as described in Section 3.19, Part II.

SERVICE CHARGE: A Service Charge of **$14.00** shall be applicable for initiating service to a customer under any Service Classification (see Part II, Section 2.01). A **$54.00** Service Charge shall be applicable for final bill readings requested to be performed other than during the normal working hours of 8 AM to 4:30 PM, Monday through Friday. (See Part II, Section 3.13)

Service Classification GST
General Service Secondary Time-Of-Day

RECONNECTION CHARGES: A Reconnection Charge, applicable after a discontinuance requested by the customer or because of a default by the customer, of **$45.00** is applicable to service reconnections which can be performed at the meter. The charge for all reconnections which cannot be performed at the meter shall be based upon the costs incurred by the Company. (See Part II, Section 7.04)

RECONNECTIONS WITHIN 12-MONTH PERIOD: Customers who request a disconnection and reconnection of service at the same location within a 12-month period shall not be relieved of Minimum Demand Charges resulting from demands created during the preceding eleven months, even though occurring prior to such disconnection.

Customers who request more than one disconnection and reconnection of service at the same location within a 12-month period shall be subject to the conditions specified above for the first such period of disconnection. In addition, for subsequent periods of disconnection, the customer shall be required to pay an additional Reconnection Charge equivalent to the sum of the Minimum Demand Charges, determined in accordance with the conditions specified in the preceding paragraph, for each month of that subsequent period.

DELINQUENT CHARGE: A Field Collection Charge of **$25.00** shall be applicable for each collection visit made to the customer's premises. (See Part II, Section 3.20)

ADDITIONAL MODIFYING RIDERS: This Service Classification may also be modified for other Rider(s), subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

Service Classification GST
General Service Secondary Time-Of-Day

VETERANS' ORGANIZATION SERVICE SPECIAL PROVISION:

Pursuant to N.J.S.A 48:2-21.41, when electric service is delivered to a customer that is a Veterans' Organization, 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 of 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.

The customer will continue to be billed on this Service Classification. At least once annually, the Company shall review eligible customers' delivery service charges under this Special Provision for all relevant periods. If the comparable delivery service charges under Service Classification RS (Residential Service) are lower than the delivery service charges under this Service Classification, a credit in the amount of the difference will be applied to the customer's next bill.

Service Classification GP
General Service Primary

APPLICABLE TO USE OF SERVICE FOR: Service Classification GP is available for general service purposes for commercial and industrial customers.

CHARACTER OF SERVICE: Single or three-phase service at primary voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy, Capacity and Reconciliation Charges as provided in Rider BGS-CIEP (Basic Generation Service – Commercial Industrial Energy Pricing).**
2) **Transmission Charge: $0.006116** per KWH for all KWH

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge: $ 61.69** per month
2) **Distribution Charge:**

KW Charge: (Demand Charge)
$ 6.43 per maximum KW during June through September
$ 5.97 per maximum KW during October through May
$ 2.18 per KW Minimum Charge

KVAR Charge: (Kilovolt-Ampere Reactive Charge)
$ 0.42 per KVAR based upon the 15-minute integrated KVAR demand which occurs coincident with the maximum on-peak KW demand in the current billing month (See Part II, Section 5.05)

KWH Charge:
$0.003671 per KWH for all KWH on-peak and off-peak

3) **Non-utility Generation Charge (Rider NGC):**
See Rider NGC for rate per KWH for all KWH on-peak and off-peak

4) **Societal Benefits Charge (Rider SBC)**:
See Rider SBC for rate per KWH for all KWH on-peak and off-peak

5) **CIEP – Standby Fee as provided in Rider CIEP – Standby Fee** (formerly Rider DSSAC)

6) **RGGI Recovery Charge (Rider RRC):**
See Rider RRC for rate per KWH for all KWH on-peak and off-peak

7) **Zero Emission Certificate Recovery Charge (Rider ZEC):**
See Rider ZEC for rate per KWH for all KWH on-peak and off-peak

8) **Tax Act Adjustment (Rider TAA):**
See Rider TAA for rate per KWH for all KWH on-peak and off-peak

9) **JCP&L Reliability Plus Charge (Rider RP):**
See Rider RP for rate per KW for all KW

10) **JCP&L Lost Revenue Adjustment Mechanism Charge (Rider LRAM):**
See Rider LRAM for rate per KW for all KW

11) **Electric Vehicle Charger Rider (Rider EV):**
See Rider EV for information about the EV Driven Program

Service Classification GP
General Service Primary

MINIMUM DEMAND CHARGE PER MONTH: The monthly KW Demand Charge under Distribution Charge shall be the greater of (1) the product of the KW Charge per maximum KW provided above and the current month's maximum demand created during on-peak hours as determined below; or (2) the product of the KW Minimum Charge provided above and the highest on-peak or off-peak demand created in the current and preceding eleven months (but not less than the Contract Demand).

DETERMINATION OF DEMAND: The KW during on-peak hours used for billing purposes shall be the maximum 15-minute integrated kilowatt demand created during the on-peak hours each billing month calculated to nearest one-tenth KW. The off-peak demand shall be the maximum demand created during the remaining hours. A Contract Demand not less than the actual monthly demands may also be specified for mutually agreeable contract purposes.

DEFINITION OF ON-PEAK AND OFF-PEAK HOURS: The hours to be considered as on-peak are from 8 a.m. to 8 p.m. prevailing time Monday through Friday. All other hours including weekend hours will be considered off-peak. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change. The off-peak hours will not be less than 12 hours daily.

TERM OF CONTRACT: None, except that reasonable notice of service discontinuance will be required. Where special circumstances apply or special or unusual facilities are supplied by the Company, a contract of one year or more to supply such facilities or accommodate special circumstances may be required for any Full Service Customer and any Delivery Service Customer.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill. Overdue bills thereafter become subject to a late payment charge as described in Section 3.19, Part II.

SERVICE CHARGE: A Service Charge of **$14.00** shall be applicable for initiating service to a customer under any Service Classification (see Part II, Section 2.01). A **$54.00** Service Charge shall be applicable for final bill readings requested to be performed other than during the normal working hours of 8 AM to 4:30 PM, Monday through Friday. (See Part II, Section 3.13)

DISCONNECTION / RECONNECTION CHARGES: Charges for all disconnections and reconnections shall be based upon actual costs. (See Part II, Section 7.04)

RECONNECTIONS WITHIN 12-MONTH PERIOD: Customers who request a disconnection and reconnection of service at the same location within a 12-month period shall not be relieved of Minimum Demand Charges resulting from demands created during the preceding eleven months, even though occurring prior to such disconnection.

Customers who request more than one disconnection and reconnection of service at the same location within a 12-month period shall be subject to the conditions specified above for the first such period of disconnection. In addition, for subsequent periods of disconnection, the customer shall be required to pay an additional Reconnection Charge equivalent to the sum of the Minimum Demand Charges, determined in accordance with the conditions specified in the preceding paragraph, for each month of that subsequent period.

ADDITIONAL MODIFYING RIDERS: This Service Classification may also be modified for other Rider(s), subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

Service Classification GP
General Service Primary

VETERANS' ORGANIZATION SERVICE SPECIAL PROVISION:

Pursuant to N.J.S.A 48:2-21.41, when electric service is delivered to a customer that is a Veterans' Organization, 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 of 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.

The customer will continue to be billed on this Service Classification. At least once annually, the Company shall review eligible customers' delivery service charges under this Special Provision for all relevant periods. If the comparable delivery service charges under Service Classification RS (Residential Service) are lower than the delivery service charges under this Service Classification, a credit in the amount of the difference will be applied to the customer's next bill.

Service Classification GT
General Service Transmission

APPLICABLE TO USE OF SERVICE FOR: Service Classification GT is available for general service purposes for commercial and industrial customers.

CHARACTER OF SERVICE: Three-phase service at transmission voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy, Capacity and Reconciliation Charges as provided in Rider BGS-CIEP (Basic Generation Service – Commercial Industrial Energy Pricing).**

2) **Transmission Charge:** **$0.005376** per KWH for all KWH
$0.001448 per KWH for all KWH High Tension Service

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge: $ 264.96** per month

2) **Distribution Charge:**

KW Charge: (Demand Charge)
$ 4.13 per maximum KW
$ 1.10 per KW High Tension Service Credit
$ 2.74 per KW DOD Service Credit

KW Minimum Charge: (Demand Charge)
$ 1.25 per KW Minimum Charge
$ 0.82 per KW DOD Service Credit
$ 0.52 per KW Minimum Charge Credit

KVAR Charge: (Kilovolt-Ampere Reactive Charge)
$ 0.41 per KVAR based upon the 15-minute integrated KVAR demand which occurs coincident with the maximum on-peak KW demand in the current billing month (See Part II, Section 5.05)

KWH Charge:
$0.002833 per KWH for all KWH on-peak and off-peak
$0.001005 per KWH High Tension Service Credit
$0.001841 per KWH DOD Service Credit

3) **Non-utility Generation Charge (Rider NGC):**
See Rider NGC for rate per KWH for all KWH on-peak and off-peak – excluding High Tension Service
See Rider NGC for rate per KWH for all KWH on-peak and off-peak – High Tension Service

4) **Societal Benefits Charge (Rider SBC)**:
See Rider SBC for rate per KWH for all KWH on-peak and off-peak

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5) **CIEP – Standby Fee as provided in Rider CIEP – Standby Fee** (formerly Rider DSSAC)

6) **RGGI Recovery Charge (Rider RRC):**
See Rider RRC for rate per KWH for all KWH on-peak and off-peak

7) **Zero Emission Certificate Recovery Charge (Rider ZEC):**
See Rider ZEC for rate per KWH for all KWH on-peak and off-peak

8) **Tax Act Adjustment (Rider TAA):**
See Rider TAA for rate per KWH for all KWH on-peak and off-peak

9) **JCP&L Reliability Plus Charge (Rider RP):**
See Rider RP for rate per KW for all KW

10) **JCP&L Lost Revenue Adjustment Mechanism Charge (Rider LRAM):**
See Rider LRAM for rate per KW for all KW

11) **Electric Vehicle Charger Rider (Rider EV):**
See Rider EV for information about the EV Driven Program

MINIMUM CHARGE PER MONTH: The monthly KW Charge (Demand Charge) under Distribution Charge shall be the greater of (1) the product of the KW Charge per maximum KW provided above and the current month's maximum demand created during on-peak hours as determined below; or (2) the product of the KW Minimum Charge provided above and the highest on-peak or off-peak demand created in the current and preceding eleven months (but not less than the Contract Demand). When the maximum on-peak demand created in the current and preceding eleven months has not exceeded 3% of the maximum off-peak demand created in the current and preceding eleven months, the KW Minimum Charge specified above shall be reduced by the KW Minimum Charge Credit stated above.

DETERMINATION OF DEMAND: The KW during on-peak hours used for billing purposes shall be the maximum 15-minute integrated kilowatt demand created during the on-peak hours each billing month calculated to nearest one-tenth KW. The off-peak demand shall be the maximum demand created during the remaining hours. A Contract Demand not less than the actual monthly demands may also be specified for mutually agreeable contract purposes.

DEFINITION OF ON-PEAK AND OFF-PEAK HOURS: The hours to be considered as on-peak are from 8 AM to 8 PM prevailing time Monday through Friday. All other hours including weekend hours will be considered off-peak. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change. The off-peak hours will not be less than 12 hours daily.

TERM OF CONTRACT: None, except that reasonable notice of service discontinuance will be required. Where special circumstances apply or special or unusual facilities are supplied by the Company, a contract of one year or more to supply such facilities or accommodate special circumstances may be required for any Full Service Customer and any Delivery Service Customer.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill. Overdue bills thereafter become subject to a late payment charge as described in Section 3.19, Part II.

SERVICE CHARGE: A Service Charge of **$14.00** shall be applicable for initiating service to a customer under any Service Classification (see Part II, Section 2.01). A **$54.00** Service Charge shall be applicable for final bill readings requested to be performed other than during the normal working hours of 8 AM to 4:30 PM, Monday through Friday. (See Part II, Section 3.13)

DISCONNECTION / RECONNECTION CHARGES: Charges for all disconnections and reconnections shall be based upon actual costs. (See Part II, Section 7.04)

RECONNECTIONS WITHIN 12-MONTH PERIOD: Customers who request a disconnection and reconnection of service at the same location within a 12-month period shall not be relieved of Minimum Demand Charges resulting from demands created during the preceding eleven months, even though occurring prior to such disconnection.

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RECONNECTIONS WITHIN 12-MONTH PERIOD: (Continued)
Customers who request more than one disconnection and reconnection of service at the same location within a 12-month period shall be subject to the conditions specified above for the first such period of disconnection. In addition, for subsequent periods of disconnection, the customer shall be required to pay an additional Reconnection Charge equivalent to the sum of the Minimum Demand Charges, determined in accordance with the conditions specified in the preceding paragraph, for each month of that subsequent period.

SPECIAL PROVISIONS:

(a) Commuter Rail Service: Where service is supplied to traction power accounts for a commuter rail system, such accounts shall be conjunctively billed based upon coincident demands. This Special Provision also modifies the DEFINITION OF ON-PEAK AND OFF-PEAK HOURS for Demand Charge purposes only, such that the following Federal Holidays are considered off-peak the entire day: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day. In addition, the periods from 8 AM to 10 AM and from 5 PM to 8 PM prevailing time Monday through Friday shall be considered as off-peak for Demand Charge purposes only. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change.

Where traction power is supplied at high tension (230 KV) and such power is being provided during a limited period to supplant power normally supplied by another utility, that limited period shall be excluded for the purpose of determining billing demand.

(b) High Tension Service: Where service is supplied at 230 KV, the determination of KW and KVAR demands shall be modified to refer to 60-minute demands, and the Distribution KW and KWH Charges, except for KW Minimum Charge, shall be reduced by the High Tension Service Credits provided above to reflect the reduced line losses associated with service at this voltage level. Any Customer taking this Special Provision shall not be qualified for Special Provisions (c) and (d) below.

(c) Department of Defense Service: Where service is supplied to the major military installations of the United States Department of Defense at transmission voltages, the Distribution KW Charge, KW Minimum Charge and KWH Charge shall be reduced by the DOD Service Credits provided above.

(d) Closing of GTX Service: Upon the closing of Service Classification GTX effective April 1, 2004, for any GTX customer as of August 1, 2003 where service is supplied at 230 KV, the monthly billing demand shall be the maximum 60-minute integrated kilowatt demand created during all on-peak and off-peak hours of the billing month and the Distribution KW Charge (Demand Charge) shall be $0.41 per KW ($0.44 per KW including SUT). The Distribution KW Minimum Charge, KVAR Charge and KWH Charge provided above shall not apply, and the Non-utility Generation Charge shall be the lesser of (1) $0.000312 per KWH ($0.000333 per KWH including SUT), or (2) the net of NGC – High Tension Service stated above and an NGC Credit of $0.009844 per KWH ($0.010496 per KWH including SUT), but not less than zero, for all KWH usage. Effective May 1, 2018 and for an initial term of 10 years, the Societal Benefits Charge (Rider SBC) shall include only the Demand Side Factor (Rider DSF) charge.

ADDITIONAL MODIFYING RIDERS: This Service Classification may also be modified for other Rider(s), subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

Service Classification GT
General Service Transmission

VETERANS' ORGANIZATION SERVICE SPECIAL PROVISION:

Pursuant to N.J.S.A 48:2-21.41, when electric service is delivered to a customer that is a Veterans' Organization, 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 of 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.

The customer will continue to be billed on this Service Classification. At least once annually, the Company shall review eligible customers' delivery service charges under this Special Provision for all relevant periods. If the comparable delivery service charges under Service Classification RS (Residential Service) are lower than the delivery service charges under this Service Classification, a credit in the amount of the difference will be applied to the customer's next bill.

6th Rev. Sheet No. 26
BPU No. 13 ELECTRIC - PART III
Superseding 5th Rev. Sheet No. 26

Service Classification OL
Outdoor Lighting Service

RESTRICTION: Mercury vapor (MV) area lighting is no longer available for replacement and shall be removed from service when existing MV area lighting fails.

APPLICABLE TO USE OF SERVICE FOR: Service Classification OL is available for outdoor flood and area lighting service operating on a standard illumination schedule of 4200 hours per year, and installed on existing wood distribution poles where secondary facilities exist. This Service is not available for the lighting of public streets and highways. This Service is also not available where, in the Company's judgment, it may be objectionable to others, or where, having been installed, it is objectionable to others.

CHARACTER OF SERVICE: Sodium vapor (SV) flood lighting, high pressure sodium (HPS) and mercury vapor (MV) area lighting for limited period (dusk to dawn) at nominal 120 volts.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):

(A) FIXTURE CHARGE:

Nominal Ratings					
Lamp Wattage	Lamp & Ballast Wattage	Billing Month KWH *	HPS Area Lighting	MV Area Lighting	SV Flood Lighting
100	121	42	Not Available	**$2.68**	Not Available
175	211	74	Not Available	**$2.68**	Not Available
70	99	35	**$11.10**	Not Available	Not Available
100	137	48	**$11.10**	Not Available	Not Available
150	176	62	Not Available	Not Available	**$13.04**
250	293	103	Not Available	Not Available	**$13.70**
400	498	174	Not Available	Not Available	**$14.06**

* Based on standard illumination schedule of 4200 hours per year. Billing Month KWH is calculated to the nearest whole KWH based on the nominal lamp & ballast wattage of the light, times the light's annual burning hours per year, divided by 12 months per year, divided by 1000 watts per KWH.

(B) KWH CHARGES: The following charges apply to all Billing Month KWH and to all billing months (January through December). All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)
2) **Transmission Charge: $0.000000** per KWH

DELIVERY SERVICE (Distribution Charge includes Corporation Business Tax as provided in Rider CBT):

1) **Distribution Charge: $0.050035** per KWH
2) **Non-utility Generation Charge (Rider NGC): See Rider NGC for rate** per KWH
3) **Societal Benefits Charge (Rider SBC): See Rider SBC for rate** per KWH
4) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
5) **Zero Emission Certificate Recovery Charge (Rider ZEC): See Rider ZEC for rate** per KWH
6) **Tax Act Adjustment (Rider TAA): See Rider TAA for rate** per KWH
7) **JCP&L Reliability Plus Charge (Rider RP): See Rider RP for rate** per Fixture
8) **JCP&L Lost Revenue Adjustment Mechanism Charge (Rider LRAM): See Rider LRAM for rate** per KWH

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Service Classification OL
Outdoor Lighting Service

TERM OF CONTRACT: One year for each installation and thereafter on a monthly basis. Service which is terminated before the end of the contract term shall be billed the total of 1) the light's monthly Fixture Charge plus 2) the per KWH Distribution Charge applicable to the light's Billing Month KWH, plus 3) any additional monthly facility charges, times the remaining months of the contract term. Restoration of Service to lamps before the end of the contract term shall be made at the expense of the customer. Restoration of Service to lamps which have been disconnected after the contract term has expired shall require a 5 year contract term to be initialized.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill.

FACILITIES:

(a) Location of Facilities: Fixtures, lamps, controls, poles, hardware, conductors, and other appurtenances necessary for Service under this Service Classification shall be owned and maintained by the Company and must be located where they can be maintained by the use of the Company's standard mechanized equipment. Should customer desire that Company relocate its outdoor lighting facilities at any time, the relocation expense shall be paid by the customer.

(b) Additional Facilities: The per Billing Month charges for poles, transformers and spans of wire furnished by the Company for Service under this Service Classification prior to February 6, 1979 shall respectively be **$0.73, $2.93** and **$0.68** until such time as there is a customer change or those facilities are no longer utilized exclusively for service under this Service Classification, or if those facilities require replacement. New or replacement facilities furnished after that date shall be provided, at the Company's option under a 5-year term of contract, based upon payment of: (1) the following per Billing Monthly charges to be added to the Flat Service Charge: 35 foot pole: **$6.70**; 40 foot pole: **$7.50** Secondary Span: **$3.38;** or (2) a single non-refundable contribution determined under Appendix A (See Tariff Part II) charges when applicable; or otherwise (3) upon payment of specific charges determined under billing work order unitized costs.

(c) Maintenance of Facilities: Maintenance of facilities furnished by the Company under this Service Classification shall be scheduled during the Company's regular business hours upon notification by the customer of the need for such service. Maintenance of facilities at times other than during the Company's regular business hours shall be performed at the expense of the customer.

SPECIAL PROVISIONS:

(a) Seasonal Service: Such Service will be rendered when the cost of disconnection and reconnection is paid by the customer. During such months of disconnection, the Billing Month KWH for the light will be zero, such that the per KWH charges for BGS Energy and Reconciliation Charges, Transmission Charge, Non-utility Generation Charge, Societal Benefits Charge, RGGI Recovery Charge, Zero Emission Certificate Recovery Charge, Tax Act Adjustment and JCP&L Lost Revenue Adjustment Mechanism Charge will not be billed. The monthly Fixture Charge, the JCP&L Reliability Plus Charge and a seasonal Distribution Charge will be billed during such months of disconnection. The seasonal Distribution Charge will be equal to the Billing Month KWH for the light on a standard illumination schedule, times the per KWH Distribution Charge.

ADDITIONAL MODIFYING RIDER: This Service Classification may also be modified for other Rider(s) subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

Service Classification SVL
Sodium Vapor Street Lighting Service

APPLICABLE TO USE OF SERVICE FOR: Service Classification SVL is available for series and multiple circuit street lighting Service operating on a standard illumination schedule of 4200 hours per year supplied from overhead or underground facilities on streets and roads (and parking areas at the option of the Company) where required by City, Town, County, State or other Municipal or Public Agency or by an incorporated association of local residents.

Sodium vapor conversions of mercury vapor or incandescent street lights shall be scheduled in accordance with the Company's SVL Conversion Program, and may be limited to no more than 5% of the lamps served under this Service Classification at the end of the previous year.

CHARACTER OF SERVICE: Sodium vapor lighting for limited period (dusk to dawn) at secondary voltage.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):

(A) FIXTURE CHARGE:

Nominal Ratings					
Lamp Wattage	Lamp & Ballast Wattage	Billing Month KWH *	Company Fixture	Contribution Fixture	Customer Fixture
50	60	21	**$ 6.48**	**$ 1.82**	**$ 0.88**
70	85	30	**$ 6.48**	**$ 1.82**	**$ 0.88**
100	121	42	**$ 6.48**	**$ 1.82**	**$ 0.88**
150	176	62	**$ 6.48**	**$ 1.82**	**$ 0.88**
250	293	103	**$ 7.67**	**$ 1.82**	**$ 0.88**
400	498	174	**$ 7.67**	**$ 1.82**	**$ 0.88**

* Based on standard illumination schedule of 4200 hours per year. Billing Month KWH is calculated to the nearest whole KWH based on the nominal lamp & ballast wattage of the light, times the light's annual burning hours per year, divided by 12 months per year, divided by 1000 watts per KWH.

(B) KWH CHARGES: The following charges apply to all Billing Month KWH and to all billing months (January through December). All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)
2) **Transmission Charge: $0.000000** per KWH

DELIVERY SERVICE (Distribution Charge includes Corporation Business Tax as provided in Rider CBT):

1) **Distribution Charge: $0.050035** per KWH
2) **Non-utility Generation Charge (Rider NGC): See Rider NGC for rate** per KWH
3) **Societal Benefits Charge (Rider SBC): See Rider SBC for rate** per KWH
4) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
5) **Zero Emission Certificate Recovery Charge (Rider ZEC): See Rider ZEC for rate** per KWH
6) **Tax Act Adjustment (Rider TAA): See Rider TAA for rate** per KWH
7) **JCP&L Reliability Plus Charge (Rider RP): See Rider RP for rate** per Fixture
8) **JCP&L Lost Revenue Adjustment Mechanism Charge (Rider LRAM): See Rider LRAM for rate** per KWH

TERM OF CONTRACT: Five years for each Company Fixture installation and thereafter on a monthly basis. Where special circumstances apply or special or unusual facilities are supplied, contracts of more than five years may be required. Service which is terminated before the end of the contract term shall be billed the total of 1) the light's monthly Fixture Charge plus 2) the per KWH Distribution Charge applicable to the light's Billing Month KWH, times the remaining months of the contract term. Restoration of Service to lamps before the end of the contract term shall be made at the expense of the customer.

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Service Classification SVL
Sodium Vapor Street Lighting Service

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill. Overdue bills thereafter become subject to a late payment charge as described in Section 3.19, Part II.

FACILITIES:

(a) Company Fixtures: Company Fixtures refer to all street lighting equipment including brackets and luminaires installed by the Company at its expense in accordance with its standard specifications, and all other equipment necessary in rendering the required Service installed on wood distribution poles or Street Light Poles. Company Fixtures shall be owned, operated, maintained and serviced by the Company.

(b) Contribution Fixtures: Contribution Fixtures refer to Company Fixtures for which installation the customer has paid the following Contributed Installation Cost. Contribution Fixtures shall be owned, operated, maintained and serviced by the Company.

Contributed Installation Cost: The Contributed Installation Cost, per fixture, shall be equal to the cost shown on Tariff Part II, Appendix A – Exhibit III, for Street Light Luminaire.

(c) Customer Fixtures: Customer fixtures refer to all customer provided and installed street lighting equipment, including brackets, luminaires, and wire required for connection by the Company to a designated point on the Company's existing distribution facilities. Such fixtures must be contiguous, and installed on customer provided and installed poles located in areas which allow them to be clearly discernable from non-customer owned street light facilities. Customer fixtures and poles must be installed in accordance with the current edition of the National Electrical Code, as well as equipment standards established and approved by the Company. Any necessary maintenance, repairs, or replacements to Customer Fixtures or poles, including lamp and control switch replacements, or luminaire cleaning, shall be made by the customer.

(d) Fixture Service: Fixture Service refers to the lamp replacement and luminaire cleaning by the Company on a scheduled basis as well as non-scheduled fixture maintenance or replacements as may be necessary. Such non-scheduled Fixture Service shall be made, where practicable, within 72 hours of notification. Fixture Service is provided for Company Fixtures and Contribution Fixtures only. Customer Fixtures currently being provided Limited Fixture Service (limited to lamp and control switch replacement plus luminaire cleaning), may continue such Service at the stated Customer Fixture Charge plus **$1.03** per Billing Month. However, Limited Fixture Service is not available for new Customer Fixture installations.

(e) Street Light Poles: Street Light Poles are defined as poles installed for street lighting purposes which are not "standard wood distribution-type poles". These street light poles are typically used for underground distribution applications, and would include aluminum, laminated wood and fiberglass poles. Street Light Poles are installed only upon payment of a non-refundable contribution determined under Appendix A (See Tariff Part II) charges when applicable, or otherwise under fixed-price billing work order costs. Street Light Poles which have previously been installed at the Company's cost shall be billed at the monthly Street Light Pole Charge set forth in Special Provision (b), or the customer may make a payment equivalent to the current installed cost of a similar pole. Street light poles may be provided on private property roadways and associated parking areas, such as apartment building and townhouse complexes. Wood distribution-type poles typically required for street light installations served from overhead distribution facilities shall be considered as distribution poles rather than street light

Service Classification SVL
Sodium Vapor Street Lighting Service

(Continued) poles. When such poles include the mounting of street lighting fixtures provided under this Service Classification, they shall be considered as "fixture-poles" and will be installed, with their associated street lighting wire, without charge to the customer. "Span-poles", which are installed to carry wire to "fixture-poles", shall be installed with their associated wire only upon payment of a non-refundable contribution determined under Appendix A charges (see Tariff Part II) when applicable, or otherwise under billing work order cost estimates. Both fixture-poles and span-poles are installed only along public roadways, or for the extension of existing street lighting service on municipal or governmental properties.

(f) General: The Company reserves the right to modify from time to time its specifications relating to street lighting equipment and its installation in order to meet changing conditions. Installations subject to vandalism may be removed at the option of the Company, unless such maintenance costs are provided by the customer.

SPECIAL PROVISIONS:

(a) Seasonal Service: Such Service will be rendered when the cost of disconnection and reconnection is paid by the customer. During such months of disconnection, the Billing Month KWH for the light will be zero, such that the per KWH charges for BGS Energy and Reconciliation Charges, Transmission Charge, Non-utility Generation Charge, Societal Benefits Charge, RGGI Recovery Charge, Zero Emission Certificate Recovery Charge, Tax Act Adjustment and JCP&L Lost Revenue Adjustment Mechanism Charge will not be billed. The monthly Fixture Charge, the JCP&L Reliability Plus Charge and a seasonal Distribution Charge will be billed during such months of disconnection. The seasonal Distribution Charge will be equal to the Billing Month KWH for the light on a standard illumination schedule, times the per KWH Distribution Charge.

(b) Street Light Pole Charge: Where the Company has installed, at its cost, a pole other than a wood distribution pole for a lamp fixture, a per Billing Month Pole Charge of **$8.64** shall be added to the Fixture Charge specified. Such charge shall not be applicable to a Street Light Pole which has had its installation cost paid for by the customer.

(c) Reduced Lighting Hours: This Special Provision is restricted to previously installed municipal parking lot lighting where the customer desires that energy for such lighting be conserved by having the Service inoperative for six hours per night and the customer reimburses the Company for the cost of any labor and materials required to provide such time control. The Billing Month KWH for lights under this Special Provision will be reduced based on 2010 annual burning hours. The monthly bill shall be the total of 1) the full monthly Fixture Charge plus 2) the reduced Billing Month KWH times all per KWH charges (BGS Energy and Reconciliation Charges, Transmission Charge, Distribution Charge, Non-utility Generation Charge, Societal Benefits Charge, RGGI Recovery Charge, Zero Emission Certificate Recovery Charge, Tax Act Adjustment and JCP&L Lost Revenue Adjustment Mechanism Charge), plus 3) a reduced lighting hours adjustment equal to the Billing Month KWH difference between the standard illumination schedule and the reduced lighting hours schedule for the light, times the per KWH Distribution Charge; plus 4) the full monthly JCP&L Reliability Plus Charge.

ADDITIONAL MODIFYING RIDER: This Service Classification may also be modified for other Rider(s) subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

Service Classification MVL
Mercury Vapor Street Lighting Service

RESTRICTION: Service Classification MVL is in process of elimination and is withdrawn except for the installations of customers receiving Service hereunder on July 21, 1982, and only for the specific premises and class of service of such customer served hereunder on such date.

APPLICABLE TO USE OF SERVICE FOR: Series and multiple circuit street lighting service operating on a standard illumination schedule of 4200 hours per year supplied from overhead or underground facilities on streets and roads where required by City, Town, County, State or other Municipal or Public Agency or by an incorporated association of local residents. At the option of the Company, Service may also be provided for lighting service on streets, roads or parking areas on municipal or private property where supplied directly from the Company's facilities when such Service is contracted for by the owner or agency operating such property.

CHARACTER OF SERVICE: Mercury vapor lighting for limited period (dusk to dawn) at secondary voltage or on constant current series circuits.

RATE PER BILLING MONTH (All charges include Sale and Use Tax as provided in Rider SUT):
(A) FIXTURE CHARGE:

Nominal Ratings					
Lamp Wattage	Lamp & Ballast Wattage	Billing Month KWH *	Company Fixture	Contribution Fixture	Customer Fixture
100	121	42	**$ 4.52**	**$ 1.72**	**$ 0.87**
175	211	74	**$ 4.52**	**$ 1.72**	**$ 0.87**
250	295	103	**$ 4.52**	**$ 1.72**	**$ 0.87**
400	468	164	**$ 4.90**	**$ 1.72**	**$ 0.87**
700	803	281	**$ 5.94**	**$ 1.72**	**$ 0.87**
1000	1135	397	**$ 5.94**	**$ 1.72**	**$ 0.87**

* Based on standard illumination schedule of 4200 hours per year. Billing Month KWH is calculated to the nearest whole KWH based on the nominal lamp & ballast wattage of the light, times the light's annual burning hours per year, divided by 12 months per year, divided by 1000 watts per KWH.

(B) KWH CHARGES: The following charges apply to all Billing Month KWH and to all billing months (January through December). All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)
2) **Transmission Charge: $0.000000** per KWH

DELIVERY SERVICE (Distribution Charge includes Corporation Business Tax as provided in Rider CBT):

1) **Distribution Charge: $0.050035** per KWH
2) **Non-utility Generation Charge (Rider NGC): See Rider NGC for rate** per KWH
3) **Societal Benefits Charge (Rider SBC): See Rider SBC for rate** per KWH
4) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
5) **Zero Emission Certificate Recovery Charge (Rider ZEC): See Rider ZEC for rate** per KWH
6) **Tax Act Adjustment (Rider TAA): See Rider TAA for rate** per KWH
7) **JCP&L Reliability Plus Charge (Rider RP): See Rider RP for rate** per Fixture
8) **JCP&L Lost Revenue Adjustment Mechanism Charge (Rider LRAM): See Rider LRAM for rate** per KWH

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1st Rev. Sheet No. 32

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Superseding Original Sheet No. 32

Service Classification MVL
Mercury Vapor Street Lighting Service

TERM OF CONTRACT: Five years for each Company Fixture installation and thereafter on a monthly basis. Where special circumstances apply or special or unusual facilities are supplied, contracts of more than five years may be required. Service which is terminated before the end of the contract term shall be billed the total of 1) the light's monthly Fixture Charge plus 2) the per KWH Distribution Charge applicable to the light's Billing Month KWH, times the remaining months of the contract term. Restoration of Service to lamps before the end of the contract term shall be made at the expense of the customer.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill. Overdue bills thereafter become subject to a late payment charge as described in Section 3.19, Part II.

FACILITIES:

(a) Company Fixtures: Company Fixtures refer to all street lighting equipment including brackets and luminaires installed by the Company at its expense in accordance with its standard specifications, and all other equipment necessary in rendering the required Service installed on wood distribution poles or Street Light Poles. Company Fixtures shall be owned, operated, maintained and serviced by the Company.

(b) Contribution Fixtures: Contribution Fixtures refer to Company Fixtures for which installation the customer has paid the following Contributed Installation Cost. Contribution Fixtures shall be owned, operated, maintained and serviced by the Company. The per Billing Month charges for Contribution Fixtures shall be discontinued only upon payment of a **$35.57** charge per fixture to cover the cost of removal.

Contributed Installation Cost:	Lamp Wattage	Lamp Wattage	Lamp Wattage
	100, 175, & 250	400	700 & 1000
For currently installed fixture:	**$141.33**	**$159.49**	**$210.97**

(c) Customer Fixtures: Customer fixtures refer to all customer provided and installed street lighting equipment, including brackets, luminaires, and wire required for connection by the Company to a designated point on the Company's existing distribution facilities. Such fixtures must be contiguous, and installed on customer provided and installed poles located in areas which allow them to be clearly discernable from non-customer owned street light facilities. Customer fixtures and poles must be installed in accordance with the equipment standards established and approved by the Company. Any necessary maintenance, repairs, or replacements to Customer Fixtures or poles, including lamp and control switch replacements, or luminaire cleaning, shall be made by the customer.

(d) Fixture Service: Fixture Service refers to the lamp replacement and luminaire cleaning by the Company on a scheduled basis as well as non-scheduled fixture maintenance or replacements as may be necessary. Such non-scheduled Fixture Service shall be made, where practicable, within 72 hours of notification. Customer Fixtures currently being provided Limited Fixture Service (limited to lamp and control switch replacement plus luminaire cleaning), may continue such Service at an additional cost of **$0.84** per Billing Month.

JERSEY CENTRAL POWER & LIGHT COMPANY

2nd Rev. Sheet No. 33

BPU No. 13 ELECTRIC - PART III

Superseding 1st Rev. Sheet No. 33

Service Classification MVL
Mercury Vapor Street Lighting Service

(e) Street Light Poles: Street Light Poles refer to all poles other than wood distribution poles, installed, owned and maintained by the Company for street lighting service. Street Light Poles are provided only upon payment by the customer for the installation cost of such pole. Street Light Poles which have previously been installed at the Company's cost, shall be billed at the per Billing Month Street Light Pole Charge set forth in Special Provision (b), or the customer may make a **$345.22** payment to cover the cost of such previous installation.

(f) General: The Company reserves the right to modify from time to time its specifications relating to street lighting equipment and its installation in order to meet changing conditions. Installations subject to vandalism may be removed at the option of the Company, unless such maintenance costs are provided by the customer.

SPECIAL PROVISIONS:

(a) Seasonal Service: Such Service will be rendered when the cost of disconnection and reconnection is paid by the customer. During such months of disconnection, the Billing Month KWH for the light will be zero, such that the per KWH charges for BGS Energy and Reconciliation Charges, Transmission Charge, Non-utility Generation Charge, Societal Benefits Charge, RGGI Recovery Charge, Zero Emission Certificate Recovery Charge, Tax Act Adjustment and JCP&L Lost Revenue Adjustment Mechanism Charge will not be billed. The monthly Fixture Charge, the JCP&L Reliability Plus Charge and a seasonal Distribution Charge will be billed during such months of disconnection. The seasonal Distribution Charge will be equal to the Billing Month KWH for the light on a standard illumination schedule, times the per KWH Distribution Charge.

(b) Street Light Pole Charge: Where the Company has installed, at its cost, a pole other than a wood distribution pole for a lamp fixture, a per Billing Month Pole Charge of **$8.64** shall be added to the Fixture Charge specified. Such charge shall not be applicable to a Street Light Pole which has had its installation cost paid for by the customer.

ADDITIONAL MODIFYING RIDER: This Service Classification may also be modified for other Rider(s) subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

JERSEY CENTRAL POWER & LIGHT COMPANY

6th Rev. Sheet No. 34

BPU No. 13 ELECTRIC - PART III

Superseding 5th Rev. Sheet No. 34

Service Classification ISL
Incandescent Street Lighting Service

RESTRICTION: Service Classification ISL is in process of elimination and is withdrawn except for the installations of customers currently receiving Service, and except for fire alarm and police box lamps provided under Special Provision (c). The obsolescence of this Service Classification's facilities further dictates that Service be discontinued to any installation that requires the replacement of a fixture, bracket or street light pole.

APPLICABLE TO USE OF SERVICE FOR: Series and multiple circuit street lighting service operating on a standard illumination schedule of 4200 hours per year supplied from overhead or underground facilities on streets or roads where required by city, town, county, State or other principal or public agency or by an incorporated association of local residents.

CHARACTER OF SERVICE: Incandescent lighting for limited period (dusk to dawn) at secondary voltage or on constant current series circuits.

RATE PER BILLING MONTH (All Charges include Sales and Use Tax as provided in Rider SUT):

(A) FIXTURE CHARGE:

Nominal Ratings Lamp Wattage	Billing Month KWH *	Company Fixture	Customer Fixture
105	37	**$ 1.91**	**$ 0.87**
205	72	**$ 1.91**	**$ 0.87**
327	114	**$ 1.91**	**$ 0.87**
448	157	**$ 1.91**	**$ 0.87**
690	242	**$ 1.91**	**$ 0.87**
860	301	**$ 1.91**	**$ 0.87**

* Based on standard illumination schedule of 4200 hours per year. Billing Month KWH is calculated to the nearest whole KWH based on the nominal lamp & ballast wattage of the light, times the light's annual burning hours per year, divided by 12 months per year, divided by 1000 watts per KWH.

(B) KWH CHARGES: The following charges apply to all Billing Month KWH and to all billing months (January through December). All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)
2) **Transmission Charge: $0.000000** per KWH

DELIVERY SERVICE (Distribution Charge includes Corporation Business Tax as provided in Rider CBT):

1) **Distribution Charge: $0.050035** per KWH
2) **Non-utility Generation Charge (Rider NGC): See Rider NGC for rate** per KWH
3) **Societal Benefits Charge (Rider SBC): See Rider SBC for rate** per KWH
4) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
5) **Zero Emission Certificate Recovery Charge (Rider ZEC): See Rider ZEC for rate** per KWH
6) **Tax Act Adjustment (Rider TAA): See Rider TAA for rate** per KWH
7) **JCP&L Reliability Plus Charge (Rider RP): See Rider RP for rate** per Fixture
8) **JCP&L Lost Revenue Adjustment Mechanism Charge (Rider LRAM): See Rider LRAM for rate** per KWH

Service Classification ISL
Incandescent Street Lighting Service

TERM OF CONTRACT: Five years for each Company Fixture installation and thereafter on a monthly basis. Where special circumstances apply or special or unusual facilities are supplied, contracts of more than five years may be required. Service which is terminated before the end of the contract term shall be billed the total of 1) the light's monthly Fixture Charge plus 2) the per KWH Distribution Charge applicable to the light's Billing Month KWH, times the remaining months of the contract term.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill. Overdue bills thereafter become subject to a late payment charge as described in Section 3.19, Part II.

FACILITIES:

(a) Company Fixtures: Company Fixtures refer to all street lighting equipment including brackets and luminaires installed by the Company at its expense in accordance with its standard specifications, and all other equipment necessary in rendering the required Service, installed on wood distribution poles or Street Light Poles. Company Fixtures shall be owned, operated, maintained and serviced by the Company.

(b) Customer Fixtures: Customer fixtures refer to all customer provided and installed street lighting equipment, including brackets, luminaires, and wire required for connection by the Company to a designated point on the Company's existing distribution facilities. Such fixtures must be contiguous, and installed on customer provided and installed poles located in areas which allow them to be clearly discernable from non-customer owned street light facilities. Customer fixtures and poles must be installed in accordance with the equipment standards established and approved by the Company. Any necessary maintenance, repairs, or replacements to Customer Fixtures or poles, including lamp and control switch replacements, or luminaire cleaning, shall be made by the customer.

(c) Fixture Service: Fixture Service refers to the lamp replacement and luminaire cleaning by the Company on a scheduled basis as well as non-scheduled lamp and control switch replacement as may be necessary. Such non-scheduled Fixture Service shall be made, where practicable, within 72 hours of notification. Customer fixtures currently being provided limited Fixture Service (limited to lamp and control switch replacement plus luminaire cleaning), may continue such Service at the stated Customer Fixture Charge plus **$1.03** per Billing Month.

(d) Street Light Poles: Street Light Poles refer to all poles, other than wood distribution poles, installed, owned and maintained by the Company for street lighting service. Replacement of Street Light Poles shall be provided only upon payment by the customer for the current installation cost of such replacement poles except when occasioned and such cost recoverable by a third party.

(e) General: The Company reserves the right to modify from time to time its specifications relating to street lighting equipment and its installation in order to meet changing conditions. Installations subject to vandalism may be removed at the option of the Company, unless such maintenance costs are provided by the customer.

Service Classification ISL
Incandescent Street Lighting Service

SPECIAL PROVISIONS:

(a) Seasonal Service: Such Service will be rendered when the cost of disconnection and reconnection is paid by the customer. During such months of disconnection, the Billing Month KWH for the light will be zero, such that the per KWH charges for BGS Energy and Reconciliation Charges, Transmission Charge, Non-utility Generation Charge, Societal Benefits Charge, RGGI Recovery Charge, Zero Emission Certificate Recovery Charge, Tax Act Adjustment and JCP&L Lost Revenue Adjustment Mechanism Charge will not be billed. The monthly Fixture Charge, the JCP&L Reliability Plus Charge and a seasonal Distribution Charge will be billed during such months of disconnection. The seasonal Distribution Charge will be equal to the Billing Month KWH for the light on a standard illumination schedule, times the per KWH Distribution Charge.

(b) Fire Alarm and Police Box Lamp Charge: 25 watt lamps serviced by the Company and served from existing secondary facilities will be billed a monthly Fixture Charge of **$1.12** and **$0.32** for lamps with individual time controls operated on a standard illumination schedule, and lamps operated 24 hours per day, respectively. Lamps with individual time controls operated on a standard illumination schedule will have a Billing Month KWH of 9 KWH. Lamps operated 24 hours per day will have a Billing Month KWH of 18 KWH. All per KWH charges (BGS Energy and Reconciliation Charges, Transmission Charge, Distribution Charge, Non-utility Generation Charge, Societal Benefits Charge, RGGI Recovery Charge, Zero Emission Certificate Recovery Charge, Tax Act Adjustment and JCP&L Lost Revenue Adjustment Mechanism Charge) will be billed based on the applicable lamp's Billing Month KWH.

ADDITIONAL MODIFYING RIDER: This Service Classification may also be modified for other Rider(s) subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

Service Classification LED
LED Street Lighting Service

APPLICABLE TO USE OF SERVICE FOR: Service Classification LED is available for installation of 12 or more LED (light emitting diode) fixtures per request for series and multiple circuit street lighting Service operating on a standard illumination schedule of 4200 hours per year supplied from overhead or underground facilities along public streets and roadways, or for the extension of existing street lighting service on municipal or governmental properties (and parking areas at the option of the Company) where required by City, Town, County, State or other Municipal or Public Agency or by an incorporated association of local residents.

CHARACTER OF SERVICE: LED lighting service is for limited period (dusk to dawn). Standard Service shall be supplied from existing lines, using the Company's standard fixtures and other appurtenances on existing wood distribution poles unrestricted as to their use by Company for purposes other than street lighting, on which existing wood distribution poles the required secondary voltage is present. The rating of the fixture in lumens is for identification and is intended to approximate the manufacturer's standard rating.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
(A) FIXTURE CHARGE:

COMPANY FIXTURES: Company Fixtures refer to fixtures installed by the Company in accordance with Standard Service and its specifications at its expense. Company Fixtures shall be owned, operated, maintained and serviced by the Company.

COMPANY FIXTURE

Lamp Wattage	Type	Lumens	Billing Month KWH*	Company Fixture
30	Cobra Head	2400	11	**$ 6.47**
50	Cobra Head	4000	18	**$ 6.43**
90	Cobra Head	7000	32	**$ 6.95**
130	Cobra Head	11500	46	**$ 7.90**
260	Cobra Head	24000	91	**$ 10.04**
50	Acorn	2500	18	**$ 16.46**
90	Acorn	5000	32	**$ 15.90**
50	Colonial	2500	18	**$ 9.24**
90	Colonial	5000	32	**$ 11.11**

CONTRIBUTION FIXTURES: Contribution Fixtures refer to fixtures installed by the Company in accordance with Standard Service and its specifications for which installation the customer has paid the Contributed Installation Cost. The Company provides two contribution levels for the Contributed Installation Cost, at the Customer's option, that have different corresponding monthly charges. Contribution Fixtures shall be owned, operated, maintained and serviced by the Company. Contribution Fixture service does not include or provide for the replacement of the fixture at failure or end of life. A contribution payment to JCP&L shall not give the customer any interest in the facilities, the ownership being vested exclusively in JCP&L.

Contributed Installation Cost: The Contributed Installation Cost, per fixture, shall be equal to the cost shown on Tariff Part II, Appendix A – Exhibit III, for Street Light Luminaire, which costs are subject to gross-up for applicable income taxes.

JERSEY CENTRAL POWER & LIGHT COMPANY

6th Rev. Sheet No. 38

BPU No. 13 ELECTRIC - PART III — Superseding 5th Rev. Sheet No. 38

Service Classification LED
LED Street Lighting Service

CONTRIBUTION FIXTURE (a)

Fixture Wattage	Type	Lumens	Billing Month KWH*	Fixture Charge	Contribution Fixture (a)
30	Cobra Head	2400	11	$ 2.65	$ 358.38
50	Cobra Head	4000	18	$ 2.65	$ 354.88
90	Cobra Head	7000	32	$ 2.65	$ 403.55
130	Cobra Head	11500	46	$ 2.65	$ 492.97
260	Cobra Head	24000	91	$ 2.65	$ 694.22
50	Acorn	2500	18	$ 2.65	$1,295.80
90	Acorn	5000	32	$ 2.65	$1,243.30
50	Colonial	2500	18	$ 2.65	$ 619.38
90	Colonial	5000	32	$ 2.65	$ 793.88

CONTRIBUTION FIXTURE (b)

Fixture Wattage	Type	Lumens	Billing Month KWH*	Fixture Charge	Contribution Fixture (b)
30	Cobra Head	2400	11	$ 4.24	$ 209.20
50	Cobra Head	4000	18	$ 4.24	$ 205.70
90	Cobra Head	7000	32	$ 4.24	$ 254.37
130	Cobra Head	11500	46	$ 4.24	$ 343.79
260	Cobra Head	24000	91	$ 4.24	$ 545.04
50	Acorn	2500	18	$ 4.24	$1,146.62
90	Acorn	5000	32	$ 4.24	$1,094.12
50	Colonial	2500	18	$ 4.24	$ 470.20
90	Colonial	5000	32	$ 4.24	$ 644.70

* Based on standard illumination schedule of 4200 hours per year. Billing Month KWH is calculated to the nearest whole KWH based on the wattage of the fixture, times the fixture's annual burning hours per year, divided by 12 months per year, divided by 1000 watts per KWH.

(B) KWH CHARGES: The following charges apply to all Billing Month KWH and to all billing months (January through December). All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)
2) **Transmission Charge: $0.000000** per KWH

DELIVERY SERVICE (Distribution Charge includes Corporation Business Tax as provided in Rider CBT):

1) **Distribution Charge: $0.050035** per KWH
2) **Non-utility Generation Charge (Rider NGC): See Rider NGC for rate** per KWH
3) **Societal Benefits Charge (Rider SBC): See Rider SBC for rate** per KWH
4) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
5) **Zero Emission Certificate Recovery Charge (Rider ZEC): See Rider ZEC for rate** per KWH
6) **Tax Act Adjustment (Rider TAA): See Rider TAA for rate** per KWH
7) **JCP&L Reliability Plus Charge (Rider RP): See Rider RP for rate** per Fixture
8) **JCP&L Lost Revenue Adjustment Mechanism Charge (Rider LRAM): See Rider LRAM for rate** per KWH

Issued: March 23, 2022 — **Effective: April 1, 2022**

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Docket No. ER22010028 dated March 9, 2022

Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

Service Classification LED
LED Street Lighting Service

TERM OF CONTRACT: Fifteen years for each fixture installation and thereafter on a monthly basis. Where special circumstances apply or special or unusual facilities are supplied, contracts of more than fifteen years may be required. Service which is terminated before the end of the contract term shall be billed the total of 1) the fixture's monthly Fixture Charge plus 2) the per KWH Distribution Charge applicable to the fixture's Billing Month KWH, times the remaining months of the contract term.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill. Overdue bills thereafter become subject to a late payment charge as described in Section 3.19, Part II.

MISCELLANEOUS:

Non-Standard Installations: Where the installation of additional facilities, including, but not limited to: poles, wire, transformers, and brackets, is required to provide service to a fixture, Customers shall be responsible for payment of a non-refundable Contribution in Aid of Construction determined under Appendix A charges (see Tariff Part II) when applicable, or otherwise under billing work order costs estimates, which costs are subject to gross-up for applicable income taxes.

(a) Changes in Fixture Wattage, Type or Location: Customers will be required to pay the cost for relocation, changes in fixture wattage, fixture type, color (Kelvin temperature) and conversion from an LED light source to another when the age of the fixture is less than 15 years. These costs will include removal cost less salvage and installation cost of the fixture. Except for relocations, the cost will also include the remaining net book value of the existing fixture and, in the case of Contribution Fixtures, payment of the Contributed Installation Cost.

i) Installation of a new fixture at the same location of the removal of an existing fixture within 12 months will be considered a replacement of the existing fixture and will be subject to charges including the removal cost less salvage for the fixture removed, the installation cost of the new fixture and, if applicable, any Contribution Installation Cost.

ii) LED conversions of sodium vapor, mercury vapor or incandescent fixtures shall be scheduled at the Company's reasonable discretion. JCP&L reserves the right to limit the number of fixtures conversions in any year to no more than 5% of the total fixtures served at the end of the previous year.

(b) Traffic Control: The Municipality will be responsible for providing and paying the costs of police assistance when deemed necessary by local authorities. The Company will provide basic traffic control (flaggers) at no cost to the Municipality. When traffic control (flagging) labor hours exceed construction labor hours (considered non-basic traffic control) the Municipality will be responsible for paying the differential in costs between basic and non-basic traffic control. The Municipality will also be responsible for all fees associated with required permitting.

(c) Seasonal Service: Such Service will be rendered when the cost of disconnection and reconnection is paid by the customer. During such months of disconnection, the Billing Month KWH for the fixture will be zero. Only the monthly Fixture Charge and a seasonal Distribution Charge will be billed (i.e., Basic Generation Service and other Delivery Service charges will not be billed) during such months of disconnection. The seasonal Distribution Charge will be equal to the Billing Month KWH for the light on a standard illumination schedule, times the per KWH Distribution Charge.

(d) General: The Company reserves the right to modify from time to time its specifications relating to street lighting equipment and its installation in order to meet changing conditions. Installations subject to vandalism may be removed at the option of the Company, unless such maintenance costs are provided by the customer.

Service Classification LED
LED Street Lighting Service

MISCELLANEOUS: (Continued)

Retrofitting of existing, non-LED street lighting: Where requested, the following shall be implemented on an interim basis, pending the resolution of the Board's current stakeholder proceeding addressing LED street lighting issues:

Option 1:

Upon failure, which shall be determined in the Company's sole discretion, and at the Customer's direction, which direction shall be set forth in an LED Replacement Agreement, the Company will replace a non-LED streetlight luminaire with an LED streetlight luminaire.

Option 2:

Where Customer requests replacement of existing non-LED streetlight luminaire with an LED streetlight luminaire, prior to its failure, the Customer is responsible for a one-time payment of the estimated average undepreciated luminaire cost (i.e., net book value) of the existing non-LED streetlight luminaire as set forth in the table below, prior to installation of the replacement LED streetlight.

Option 3:

Where Customer requests replacement of existing non-LED streetlight luminaire with an LED streetlight luminaire, prior to its failure, the Customer shall enter into a Payment Agreement with the Company and shall be responsible for payment for the estimated average undepreciated non-LED luminaire cost (i.e., net book value) of the existing non-LED streetlight luminaire in equal payments over a 60-month period, as set forth in the table below. In the event of termination of service under this Schedule, for any reason prior to the expiration of the Payment Agreement, prior to termination of service, the Customer shall pay to the Company any and all amounts due under the Payment Agreement and all costs associated with removal of the LED streetlights.

LED Streetlight – Stranded Costs

SVL

	Option #2 One-time Payment	Option #3 Equal Payment 60-month Period
Cobra Head	$352	$7.36
Acorn	$861	$18.01
Colonial	$493	$10.31

MVL

	Option #2 One-time Payment	Option #3 Equal Payment 60-month Period
Cobra Head	$201	$4.21
Acorn	$509	$10.65
Colonial	$287	$6.00

ADDITIONAL MODIFYING RIDER: This Service Classification may also be modified for other Rider(s) subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

JERSEY CENTRAL POWER & LIGHT COMPANY

2nd Rev. Sheet No. 41

BPU No. 13 ELECTRIC - PART III

Superseding 1st Sheet No. 41

Rider BGS-RSCP
Basic Generation Service – Residential Small Commercial Pricing
(Applicable to Service Classifications RS, RT, RGT, GS, GST, OL, SVL, MVL, ISL and LED)

Effective June 1, 2015, Rider BGS-FP (Basic Generation Service – Fixed Pricing) is renamed Rider BGS-RSCP to comply with the BPU Order dated November 24, 2014 (Docket No. ER14040370).

AVAILABILITY: Rider BGS-RSCP is available to and provides Basic Generation Service (default service) charges applicable to all KWH usage for Full Service Customers taking service at secondary voltages under Service Classifications RS, RT, RGT, GS, GST, OL, SVL, MVL, ISL and LED, except for GS and GST customers that have a peak load share of 500 KW or greater as of November 1, 2021. Rider BGS-RSCP-eligible GS and GST customers may elect to take default service under Rider BGS-CIEP no later than the second business day in January of each year. Such election will be effective June 1 of that year and Rider BGS-CIEP will remain the customer's default service for the entire 12-month period from June 1 through May 31 of the following year. BGS-RSCP-eligible customers who have elected to take default service under BGS-CIEP may return to BGS-RSCP by notifying the Company no later than the second business day in January of each year. Such notification to return to BGS-RSCP will become effective June 1 of that year.

RATE PER BILLING MONTH: (For service rendered effective June 1, 2022 through May 31, 2023)
1) BGS Energy Charge per KWH: (All charges include Sales and Use Tax as provided in Rider SUT.)

Service Classification	June through September	October through May
RS - first 600 KWH	**$0.071484**	
- all KWH over 600	**$0.080709**	
- all KWH		**$0.081471**
(Excludes off-peak and controlled water heating special provisions)		
RT - all on-peak KWH	**$0.102557**	**$0.103818**
- all off-peak KWH	**$0.054151**	**$0.057373**
RGT - all on-peak KWH	**$0.102557**	
- all off-peak KWH	**$0.054151**	
- all KWH		**$0.081471**
RS and GS Water Heating – all KWH	**$0.074607**	**$0.074395**
(For separately metered off-peak and controlled water heating usage under applicable special provisions)		
GS - all KWH	**$0.074746**	**$0.074466**
(Excludes off-peak and controlled water heating special provisions)		
GST - all on-peak KWH	**$0.094431**	**$0.088547**
- all off-peak KWH	**$0.054711**	**$0.056672**
OL, SVL, MVL, ISL, LED - all KWH	**$0.057863**	**$0.058494**

BGS Energy Charges above reflect costs for energy, generation capacity, ancillary services and related cost.

Issued: May 13, 2022 **Effective: June 1, 2022**

Filed pursuant to Order of Board of Public Utilities
Docket No. ER21030631 dated February 9, 2022

Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

Rider BGS-RSCP
Basic Generation Service – Residential Small Commercial Pricing
(Applicable to Service Classifications RS, RT, RGT, GS, GST, OL, SVL, MVL, ISL and LED)

2) BGS Transmission Charge per KWH: As provided in the respective tariff for Service Classifications RS, RT, RGT, GS, GST, OL, SVL, MVL, ISL and LED. Effective September 1, 2019, a RMR surcharge of **$0.000000** per KWH (includes Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage.

Effective **December 15, 2021**, the following TEC surcharges (include Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage, except lighting under Service Classifications OL, SVL, MVL, ISL and LED:

EL18-680FM715-TEC surcharge of **$0.000000** per KWH

Effective **April 1, 2022**, the following TEC surcharges (include Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage, except lighting under Service Classifications OL, SVL, MVL, ISL and LED:

PSEG-TEC surcharge of **$0.002959** per KWH
VEPCO-TEC surcharge of **$0.000300** per KWH
PATH-TEC surcharge of **$0.000007** per KWH
AEP-East-TEC surcharge of **$0.000076** per KWH
MAIT-TEC surcharge of **$0.000076** per KWH
EL05-121-TEC surcharge of **$0.000235** per KWH
SRE-TEC surcharge of **$0.000200** per KWH
NIPSCO-TEC surcharge of **$0.000002** per KWH
SFC-TEC surcharge of **$0.000004** per KWH

Effective **September 1, 2022**, the following TEC surcharges (include Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage, except lighting under Service Classifications OL, SVL, MVL, ISL and LED:
TRAILCO-TEC surcharge of **$0.000208** per KWH
ACE-TEC surcharge of **$0.000098** per KWH
PECO-TEC surcharge of **$0.000068** per KWH
PPL-TEC surcharge of **$0.000643** per KWH
Delmarva-TEC surcharge of **$0.000005** per KWH
PEPCO-TEC surcharge of **$0.000013** per KWH
BG&E-TEC surcharge of **$0.000016** per KWH
COMED-TEC surcharge of **$0.000000** Per KWH
Duquesne-TEC surcharge of **$0.000000** Per KWH

3) BGS Reconciliation Charge per KWH: ($0.001659) (includes Sales and Use Tax as provided in Rider SUT)
The above BGS Reconciliation Charge recovers the difference between the costs for the provision of Basic Generation Service and the revenues from BGS customers for Basic Generation Service and is subject to quarterly true-ups.

Rider BGS-CIEP
Basic Generation Service – Commercial Industrial Energy Pricing
(Applicable to Service Classifications GP and GT and Certain Customers under Service Classifications GS and GST)

AVAILABILITY: Rider BGS-CIEP is available to and provides Basic Generation Service (default service) charges applicable to all Full Service Customers taking service at primary and transmission voltages under Service Classifications GP and GT and any Full Service Customers taking service at secondary voltages under Service Classifications GS and GST that have a peak load share of 500 KW or greater as of November 1, 2021, or that have elected to take BGS-CIEP service no later than the second business day in January of each year. All BGS-CIEP customers remain subject to this Rider for the entire 12-month period from June 1 of any given year through May 31 of the following year.

RATE PER BILLING MONTH:
(For service rendered effective June 1, 2022 through May 31, 2023)

1) BGS Energy Charge per KWH: The sum of actual real-time PJM load weighted average Residual Metered Load Aggregate Locational Marginal Price for JCP&L Transmission Zone and ancillary services of **$0.00600** per KWH, times the Losses Multiplier provided below, times 1.06625 multiplier for Sales and Use Tax as provided in Rider SUT.

Losses Multiplier:	GT – High Tension Service	1.005
	GT	1.027
	GP	1.047
	GST	1.103
	GS	1.103

2) BGS Capacity Charge per KW of Generation Obligation: **$0.25480** per KW-day times BGS-CIEP customer's share of the capacity peak load assigned to the JCP&L Transmission Zone by the PJM Interconnection, L.L.C., as adjusted by PJM assigned capacity related factors, times 1.06625 multiplier for Sales and Use Tax as provided in Rider SUT.

3) BGS Transmission Charge per KWH: As provided in the respective tariff for Service Classifications GS, GST, GP and GT. Effective September 1, 2019, a RMR surcharge will be added to the BGS Transmission Charge applicable to all KWH usage, as follows (includes Sales and Use Tax as provided in Rider SUT):

GT – High Tension Service	**$0.000000**
GT	**$0.000000**
GP	**$0.000000**
GS and GST	**$0.000000**

Rider BGS-CIEP
Basic Generation Service – Commercial Industrial Energy Pricing
(Applicable to Service Classifications GP and GT and Certain Customers under Service Classifications GS and GST)

3) BGS Transmission Charge per KWH: (Continued)

Effective **December 15, 2021**, the following TEC surcharges (include Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage:

	EL18-680Fm715-TEC
GS and GST	**$0.000000**
GP	**$0.000000**
GT	**$0.000000**
GT – High Tension Service	**$0.000000**

Effective **April 1, 2022**, the following TEC surcharges (include Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage:

	PSEG-TEC	VEPCO-TEC	PATH-TEC	AEP-East-TEC	
GS and GST	**$0.002959**	**$0.000300**	**$0.000007**	**$0.000076**	
GP	**$0.001800**	**$0.000182**	**$0.000004**	**$0.000046**	
GT	**$0.001581**	**$0.000160**	**$0.000004**	**$0.000041**	
GT – High Tension Service	**$0.000425**	**$0.000043**	**$0.000001**	**$0.000011**	
	MAIT-TEC	EL05-121-TEC	SRE-TEC	NIPSCO-TEC	SFC-TEC
GS and GST	**$0.000076**	**$0.000235**	**$0.000200**	**$0.000002**	**$0.000004**
GP	**$0.000046**	**$0.000143**	**$0.000122**	**$0.000001**	**$0.000002**
GT	**$0.000041**	**$0.000126**	**$0.000107**	**$0.000001**	**$0.000002**
GT – High Tension Service	**$0.000011**	**$0.000034**	**$0.000029**	**$0.000000**	**$0.000001**

Effective **September 1, 2022**, the following TEC surcharges (include Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage:

	TRAILCO-TEC	ACE-TEC	PECO-TEC	Delmarva-TEC	
GS and GST	**$0.000208**	**$0.000098**	**$0.000068**	**$0.000005**	
GP	**$0.000124**	**$0.000059**	**$0.000041**	**$0.000003**	
GT	**$0.000113**	**$0.000053**	**$0.000037**	**$0.000003**	
GT – High Tension Service	**$0.000033**	**$0.000016**	**$0.000011**	**$0.000001**	
	PPL-TEC	PEPCO-TEC	BG&E-TEC	COMED-TEC	Duquesne-TEC
GS and GST	**$0.000643**	**$0.000013**	**$0.000016**	**$0.000000**	**$0.000000**
GP	**$0.000383**	**$0.000007**	**$0.000010**	**$0.000000**	**$0.000000**
GT	**$0.000350**	**$0.000006**	**$0.000009**	**$0.000000**	**$0.000000**
GT – High Tension Service	**$0.000102**	**$0.000002**	**$0.000002**	**$0.000000**	**$0.000000**

4) BGS Reconciliation Charge per KWH: ($0.000044) (includes Sales and Use Tax as provided in Rider SUT)

The above BGS Reconciliation Charge recovers the difference between the costs for the provision of Basic Generation Service and the revenues from BGS customers for Basic Generation Service and is subject to quarterly true-ups.

2nd Rev. Sheet No. 45
BPU No. 13 ELECTRIC - PART III Superseding 1st Sheet No. 45

Rider CIEP – Standby Fee
Commercial Industrial Energy Pricing Standby Fee
(Applicable to Service Classifications GP and GT and Certain Customers under Service Classifications GS and GST)

Effective June 1, 2007, Rider DSSAC (Default Supply Service Availability Charge) is renamed Rider CIEP – Standby Fee to comply with the BPU Order dated December 22, 2006 (Docket No. EO06020119).

APPLICABILITY: Rider CIEP – Standby Fee provides a charge applicable to all KWH usage of all Full Service Customers or Delivery Service Customers taking service under Service Classifications GP and GT and any Full Service Customer or Delivery Service Customer taking service under Service Classifications GS and GST that has a peak load share of 500 KW or greater as of November 1, 2021, or that has elected to take Basic Generation Service-Commercial Industrial Energy Pricing under Rider-CIEP no later than the second business day in January of each year. This charge is applicable for service rendered from June 1, 2022 through May 31, 2023 to recover costs associated with administrating and maintaining the availability of the hourly-priced default Basic Generation Service for these customers.

CIEP – Standby Fee per KWH: $0.000150

(**$0.000160** including Sales and Use Tax as provided in Rider SUT)

JERSEY CENTRAL POWER & LIGHT COMPANY

2nd Rev. Sheet No. 46

BPU No. 13 ELECTRIC - PART III

Superseding 1st Rev. Sheet No. 46

Rider NGC
Non-utility Generation Charge

APPLICABILITY: Rider NGC provides a non-utility generation charge ("NGC") applicable to all KWH usage of any Full Service Customer or Delivery Service Customer. Effective September 1, 2004, Rider MTC ("Market Transition Charge") is renamed Rider NGC to comply with the BPU Final Order dated May 17, 2004 (Docket Nos. ER02080506, etc.) that "the MTC shall be discontinued and renamed the NGC" for customer billing purposes.

Effective August 1, 2003, the Company recovers through the MTC charge, the MTC deferred balance which includes: (1) BPU-approved costs incurred during the transition to a competitive retail market and under-recovered during the period from August 1, 1999 through July 31, 2003; and (2) all BPU-approved costs associated with committed supply energy, capacity and ancillary services, net of all revenues from the sale of the committed supply in the wholesale market (Docket Nos. EX01110754 and EX01050303, etc.) Carrying cost shall be computed on a monthly basis at the applicable BPU-approved interest rate on the average net-of-tax over or under-recovered balance of the MTC, compounded annually.

Effective August 1, 2003, the composite MTC Factor shall be $0.011013 per KWH (excluding SUT), which includes the interim recovery of MTC deferred balance as of July 31, 2003, until the BPU's decision on the securitization of the MTC deferred balance.

Effective June 1, 2005, the composite MTC Factor shall be reduced to $0.010614 per KWH (excluding SUT), which includes the anticipation of the savings to be realized from the securitization of a portion of the MTC deferred balance as of July 31, 2003 ("Deferred BGS Transition Costs") pending the BPU approval. By Order dated June 8, 2006, the BPU approved the securitization of Deferred BGS Transition Costs.

Effective December 6, 2006, the composite MTC/NGC Factor shall be $0.015492 per KWH (excluding SUT), which includes an increase in the NGC Factor of $0.004878 per KWH.

Effective March 1, 2011, the composite MTC/NGC Factor shall be $0.007687 per KWH (excluding SUT), which includes a decrease in the NGC Factor of $0.007805 per KWH.

Effective March 1, 2012, the composite MTC/NGC Factor shall be $0.002839 per KWH (excluding SUT), which includes a decrease in the NGC Factor of $0.004848 per KWH.

Effective February 2, 2015, the composite MTC/NGC Factor shall be $0.003750 per KWH (excluding SUT), which includes an increase in the NGC Factor of $0.000911 per KWH.

Effective September 1, 2016, the composite MTC/NGC Factor shall be $0.005012 per KWH (excluding SUT), which includes an increase in the NGC Factor of $0.001262 per KWH. By Board Order dated May 31, 2017 (Docket No. ER16101046), the Board approved no change to this Factor for the 2015 NGC Filing.

Effective June 10, 2017, the composite MTC/NGC Factor shall be $0.001527 per KWH (excluding SUT), which includes a decrease in the NGC Factor of $0.001548 per KWH and the OC-TBC and OC-MTC-Tax associated with the securitization of Oyster Creek at zero rate. By Board Order dated September 17, 2018 (Docket No. ER17030306), the Board approved no change to this Factor for the 2016 NGC Filing.

Effective November 1, 2018, the composite MTC/NGC Factor shall be $0.000451 per KWH (excluding SUT), which includes a decrease in the NGC Factor of $0.001076 per KWH. By Board Order dated June 12, 2019 (Docket No. ER18090977), the Board approved no change to this Factor for the 2017 NGC Filing.

Effective January 1, 2020, the composite MTC/NGC Factor shall be $0.000105 per KWH (excluding SUT), which includes a decrease in the NGC Factor of $0.000346 per KWH. By Board Order dated December 2, 2020 (Docket No. ER20060473), the Board approved no change to this Factor for the 2019 NGC Filing.

Effective November 15, 2021, the MTC/NGC Factor shall be -$0.000215 per KWH (excluding SUT), with the DB-TBC and DB-MTC-Tax associated with the securitization of Deferred BGS Transition Costs at zero Rate.

Issued: November 12, 2021 **Effective: November 15, 2021**

Filed pursuant to Order of Board of Public Utilities
Docket No. ER21010083 dated October 28, 2021

Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

JERSEY CENTRAL POWER & LIGHT COMPANY

1st Rev. Sheet No. 47

BPU No. 13 ELECTRIC - PART III

Superseding Original. Sheet No. 47

Rider NGC
Non-utility Generation Charge

For billing purposes, the composite MTC/NGC Factor of -$0.000215 per KWH shall be applied to all KWH usage of any Full Service Customer or Delivery Service Customer as follows:

Voltage Adjusted MTC Charges per KWH (renamed NGC Charges per KWH)		Including SUT
Secondary Voltages	**-$0.000219**	**-$0.000234**
(Applicable to Service Classifications RS, RT, RGT, GS, GST, OL, SVL, MVL, ISL and LED)		
Primary Voltages	**-$0.000208**	**-$0.000222**
(Applicable to Service Classification GP)		
Transmission Voltages	**-$0.000204**	**-$0.000218**
High Tension Service (230 KV)	**-$0.000200**	**-$0.000213**
(Applicable to Service Classification GT)		

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JERSEY CENTRAL POWER & LIGHT COMPANY

2nd Rev. Sheet No. 48
BPU No. 13 ELECTRIC - PART III Superseding 1st Rev. Sheet No. 48

Rider NGC
Non-utility Generation Charge

Securitization of Oyster Creek

On February 6, 2002, the BPU approved and issued a Bondable Stranded Costs Rate Order ("Oyster Creek Rate Order") (Docket No. EF99080615) authorizing the issuance and sale of up to $320 million aggregate principal amount of transition bonds to recover certain bondable stranded costs related to the investment in the Oyster Creek Nuclear Generating Station, the imposition of a non-bypassable Transition Bond Charge ("OC-TBC") for the recovery of such costs and the related Market Transition Charge-Tax ("OC-MTC-Tax). The bondable stranded costs are defined in the Oyster Creek Rate Order and include: (1) the capital reduction costs, (2) the upfront transaction costs and (3) the ongoing transition bond costs.

Effective June 11, 2002, the MTC included an OC-TBC of $0.001921 per KWH and an OC-MTC-Tax of $0.000505 per KWH (or $0.002036 per KWH and $0.000535 per KWH including SUT, respectively). The OC-TBC and OC-MTC-Tax are governed by the provisions of the Oyster Creek Rate Order and are subject to periodic true-ups, at least annually but not more frequently than quarterly, except monthly true-ups are permitted in the last year before the scheduled maturity of the transition bonds and continuing until final maturity, as provided in the Oyster Creek Rate Order.

On February 28, 2017, a true-up letter was filed with the BPU in accordance with the provisions in the Oyster Creek Rate Order. Effective May 1, 2017 through May 6, 2017, the OC-TBC and OC-MTC-Tax shall be $0.001198 per KWH and $0.000739 per KWH, respectively (or $0.001280 per KWH and $0.000790 per KWH including SUT, respectively). Effective May 7, 2017, the OC-TBC and OC-MTC-Tax shall be at zero.

Securitization of Deferred BGS Transition Costs

By Order dated June 8, 2006, the BPU approved and issued a Bondable Stranded Costs Rate Order ("Deferred BGS Transition Costs Rate Order") (Docket No. ER03020133) authorizing the issuance and sale of $182.4 million aggregate principal amount of transition bonds to recover the Company's net of tax deferred basic generation service transition costs incurred during the transition period from August 1, 1999 through July 31, 2003, the imposition of a non-bypassable Transition Bond Charge ("DB-TBC") for the recovery of such costs and the related Market Transition Charge-Tax ("DB-MTC-Tax"). The bondable stranded costs are defined in the Deferred BGS Transition Costs Rate Order and include: (1) the upfront transaction costs and (2) the ongoing transition bond costs.

Effective August 10, 2006, the NGC included a DB-TBC of $0.001230 per KWH and a DB-MTC-Tax of $0.000572 per KWH (or $0.001316 per KWH and $0.000612 per KWH including SUT, respectively). The DB-TBC and DB-MTC-Tax are governed by the provisions of the Deferred BGS Transition Costs Rate Order and are subject to periodic true-ups, at least annually but not more frequently than quarterly, and continuing until final maturity, as provided in the Deferred BGS Transition Costs Rate Order.

On February 28, 2021, a true-up letter was filed with the BPU in accordance with the provisions in the Deferred BGS Transition Costs Rate Order. Effective May 1, 2021 through May 10, 2021, the DB-TBC and DB-MTC-Tax shall continue to be $0.000735 per KWH and $0.000321 per KWH, respectively (or $0.000784 per KWH and $0.000342 per KWH including SUT, respectively). Effective May 11, 2021, the DB-TBC and DB-MTC-Tax shall be at zero.

Rider NGC
Non-utility Generation Charge

St. Lawrence Hydroelectric Power

At the November 9, 2004 agenda meeting, the BPU verbally approved, among other things, the Public Power Association of New Jersey ("PPANJ") as Bargaining Agent for the State of New Jersey to renegotiate with the New York Power Authority ("NYPA"), on the allocation of service tariff capacity and associated energy produced at the St. Lawrence/FDR project (In the Matter of the Allocation of St. Lawrence Hydroelectric Power to the State of New Jersey Docket No. EO04101124).

On December 21, 2004, the PPANJ filed with the BPU the following documents associated with the St. Lawrence Hydroelectric Power matter: 1) Agreement for Electric Service Investor Owned Utility Between the PPANJ and JCP&L, PSE&G, Rockland Electric and Atlantic City Electric Company; 2) Agreement Governing Administration of NYPA Power ("Administration Agreement"); and 3) PPANJ for State of New Jersey Service Tariff Capacity and Associated Energy.

Pursuant to the Administration Agreement, the Company, as Nominal Recipient of the Investor-Owned Electric Utilities' share of St. Lawrence/FDR project, is responsible to deliver and distribute the capacity and associated energy as Basic Generation Service to residential customers as designated by the BPU. In addition, the Company is responsible to distribute to each of the Investor-Owned Electric Utilities the Net Economic Benefits calculated according to the Rate Schedule attached to the Administration Agreement. Each of the Investor-Owned Electric Utilities shall allocate the Net Economic Benefits distributed to it to its residential customers through the Investor-Owned Electric Utility's applicable clause through which it recovers non-utility generation costs, or other appropriate rate mechanism if no such clause exists, in a manner that ensures that such benefits flow exclusively to residential customers.

The Company, in its role as Nominal Recipient of the St. Lawrence/FDR project, advises the Investor-Owned Electric Utilities of their respective allocation of the Net Economic Benefits for the period started January 1, 2019 through January 31, 2020. JCP&L's share of the Net Economic Benefits totaled $137,272.61.

Effective June 1, 2020 through May 31, 2021, a St. Lawrence Hydroelectric Power **credit** of **$0.000015** per KWH **($0.000016** per KWH including SUT) will be combined with the Secondary Voltages Adjusted NGC Charge applicable to Service Classifications RS, RT and RGT. Such combined NGC Charge shall be applied to all KWH usage of any Full Service or Delivery Service residential customers.

Effective February 1, 2020, St. Lawrence Allocation shall be exclusively assigned to the municipally owned utilities and rural electric cooperative in New Jersey. The Company ceases to receive any Net Economic Benefits of St. Lawrence Project's allocation.

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5th Rev. Sheet No. 50
BPU No. 13 ELECTRIC - PART III Superseding 4th Rev. Sheet No. 50

Rider SBC
Societal Benefits Charge

APPLICABILITY: Rider SBC provides a charge applicable to all KWH usage of any Full Service Customer or Delivery Service Customer. The charges that may be included in calculating the SBC include nuclear plant decommissioning costs (Rider NDC), demand side management costs (Rider DSF), manufactured gas plant remediation costs (Rider RAC), uncollectible costs (Rider UNC), and universal service fund costs (Rider USF), in accordance with the New Jersey Electric Discount and Energy Competition Act. The current SBC includes the following charges per KWH:

		Including SUT
Rider DSF	**$0.003280**	**$0.003497**
Rider NDC	**$0.000000**	**$0.000000**
Rider RAC	**$0.000806**	**$0.000859**
Rider UNC	**$0.000352**	**$0.000375**
Rider USF	**$0.003940**	**$0.004201**

Carrying costs on unamortized balances of demand side management costs, nuclear decommissioning costs, manufactured gas plant remediation costs, uncollectible costs and universal service fund costs shall be calculated in accordance with the terms of Rider DSF, Rider NDC, Rider RAC, Rider UNC and Rider USF, respectively.

Effective October 1, 2022, the SBC shall be applied to all KWH usage for billing purposes as follows:

		Including SUT
Total SBC:	**$0.008378**	**$0.008932**

Beginning January 1, 2011, with the exception of universal service fund costs component, all over- and under-recoveries of individual SBC components are to be applied to under- or over-recoveries of other SBC components as of each December 31.

1st Rev. Sheet No. 51
BPU No. 13 ELECTRIC - PART III Superseding Original Sheet No. 51

Rider DSF
Demand Side Factor

APPLICABILITY: Rider DSF provides a charge for costs associated with New Jersey Clean Energy Program. The DSF is included in the Societal Benefits Charge applicable to all KWH usage of any Full Service Customer or Delivery Service Customer.

DSF = $0.003280 per KWH ($0.003497 per KWH including SUT)

Demand Side Factor costs include carrying costs on any unamortized balances of such costs at the applicable interest approved by the BPU in its Final Order dated May 17, 2004 (Dockets Nos. ER02080506, et al.), such interest rate shall be the rate actually incurred on the Company's short-term debt (debt maturing in one year or less), or the rate on equivalent temporary cash investments if the Company has no short-term debt outstanding. Interest shall be computed monthly based on the beginning and ending average monthly balance net of deferred income taxes, compounded annually (added to the balance on which interest is accrued annually) on January 1 of each year.

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1st Rev. Sheet No. 52

BPU No. 13 ELECTRIC - PART III

Superseding Original Sheet No. 52

Rider NDC
Nuclear Decommissioning Costs

APPLICABILITY: Rider NDC provides a charge for Nuclear Decommissioning costs. The NDC is included in the Societal Benefits Charge applicable to all KWH usage of any Full Service Customer or Delivery Service Customer.

NDC = $0.000000 per KWH ($0.000000 per KWH including SUT)

Nuclear Decommissioning costs include carrying costs on any unamortized balances of such costs at the applicable interest rate approved by the BPU in its Final Order dated May 17, 2004 (Docket Nos. ER02080506, et al.). Such interest rate shall be the rate actually incurred on the Company's short-term debt (debt maturing in one year or less), or the rate on equivalent temporary cash investments if the Company has no short-term debt outstanding. Interest shall be computed monthly based on the beginning and ending average monthly balance net of deferred income taxes, compounded annually (added to the balance on which interest is accrued annually) on January 1 of each year.

2nd Rev. Sheet No. 53
BPU No. 13 ELECTRIC - PART III Superseding 1st Rev. Sheet No. 53

Rider RAC
Remediation Adjustment Clause

APPLICABILITY: Rider RAC determines a Remediation Adjustment in accordance with the formula set forth below. The factor is included in the Societal Benefits Charge applicable to all KWH usage of any Full Service Customer or Delivery Service Customer.

The calculated RAC rate shall be prepared by the Company and filed with the BPU annually by the end of December with a requested effective date of June 1 of the subsequent year. Rider RAC provides for the recovery of manufactured gas plant remediation costs (net of insurance and other recoveries) over rolling seven year periods, including carrying costs on the unamortized balance. Carrying cost is calculated on a monthly basis at an interest rate equal to the rate on seven-year constant maturity Treasuries, as shown in the Federal Reserve Statistical Release on or closest to January 1 of each year, plus sixty basis points, compounded annually as of January 1 of each year.

CALCULATION OF THE REMEDIATION ADJUSTMENT CLAUSE FACTOR:

1) By using the following formula:

RAC = Recoverable Cost / Sales

2) Where the terms are defined as follows:

RAC = The Remediation Adjustment Clause factor in cents per KWH to be applied to all applicable retail KWH sales.

Recoverable Cost = Manufactured Gas Plant remediation expenses (net of insurance and other recoveries) amortized over rolling seven year periods. The cost includes carrying costs on any unamortized balance of remediation costs, net of associated deferred tax balance, at an annual interest rate stated above.

Sales = The Company's forecasted retail KWH sales.

3) Effective September 1, 2022, the RAC computation is as follows ($ Millions):

RAC = $15.454 / 19,185,264 MWH = $0.000806 per KWH
($0.000859 per KWH including SUT)

1st Rev. Sheet No. 54
BPU No. 13 ELECTRIC - PART III Superseding Original. Sheet No. 54

Rider UNC
Uncollectible Accounts Charge

APPLICABILITY: Rider UNC provides a charge for costs associated with uncollectible accounts recorded in FERC account 904 (Uncollectible Accounts). The UNC is included in the Societal Benefits Charge applicable to all KWH usage of any Full Service Customer or Delivery Service Customer.

UNC = $0.000352 per KWH ($0.000375 per KWH including SUT)

Uncollectible costs include carrying costs on any unamortized balances of such costs at the applicable interest rate approved by the BPU in its Final Order dated May 17, 2004 (Docket Nos. ER02080506, et al.). Such interest rate shall be the rate actually incurred on the Company's short-term debt (debt maturing in one year or less), or the rate on equivalent temporary cash investments if the Company has no short-term debt outstanding. Interest shall be computed monthly based on the beginning and ending average monthly balance net of deferred income taxes, compounded annually (added to the balance on which interest is accrued annually) on January 1 of each year.

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2nd Rev. Sheet No. 55

BPU No. 13 ELECTRIC - PART III

Superseding 1st Rev. Sheet No. 55

Rider USF
Universal Service Fund Costs Recovery

APPLICABILITY: Rider USF provides a charge for costs associated with the state-mandated Universal Service Fund ("USF") to assist certain customers as defined by the BPU. The USF is included in the Societal Benefits Charge and is applicable to all KWH usage of any Full Service Customer or Delivery Service Customer.

Effective October 1, 2022, the USF provided below consists of an USF rate of $0.003205 per KWH and a Lifeline rate of $0.000735 per KWH ($0.003417 per KWH and $0.000784 per KWH including SUT, respectively), pursuant to the BPU Order dated September 28, 2022 (Docket No. ER22060374).

USF = $0.003940 per KWH ($0.004201 per KWH including SUT)

Universal Service Fund costs shall accrue interest on any over or under recovered balances of such costs at the interest rate based on a two-year constant maturity Treasuries as published in the Federal Reserve Statistical Release on the first day of each month (or the closest day thereafter on which rates are published), plus sixty basis points, but shall not exceed the Company's overall rate of return as approved by the BPU. Such interest rate shall be reset each month. The interest calculation shall be based on the net of tax beginning and end average monthly balance, consistent with the methodology in the Board's Final Order dated May 17, 2004 (Docket No. ER02080506 et al.), accrue monthly with an annual roll-in at the end of each reconciliation period.

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BPU No. 13 ELECTRIC - PART III Original Sheet No. 56

Rider QFS
Cogeneration and Small Power Production Service

AVAILABILITY: Rider QFS specifies the conditions under which the Company will purchase electricity from a "Qualifying Facility" ("QF") under Section 210 of the Public Utilities Regulatory Policies Act of 1978. Rider QFS is available to customers taking service under Service Classifications GS, GST, GP and GT. QF installations must conform to, and are responsible for all costs associated with, the Company's General Interconnect Requirements for Customer's Generation, according to any applicable installation specifications. (See Part II, Section 10)

QF INSTALLATIONS WITH MORE THAN 1000 KW GENERATING CAPACITY

Such installations shall negotiate with the Company for specific contract arrangements to determine the price, term and conditions to delivered energy and capacity, where applicable; provided however, that in no event shall payments to the QF installation under this tariff exceed the revenues the Company receives from PJM (or its successor), net of PJM penalties and charges. Such contracts are subject to BPU approval.

QF INSTALLATIONS WITH 1000 KW OR LESS GENERATING CAPACITY

Service Charge: $40.00 monthly

Energy Payment: Based on actual real-time PJM load weighted average Residual Metered Load Aggregate Locational Marginal Price (LMP) for the JCP&L Transmission Zone at the time when the QF installation delivers energy to the Company.

Capacity Payment: Deliveries from a QF installation that qualify as a PJM Capacity Resource may receive capacity payments when the installed capacity of the QF installation exceeds 100 kW and meets the reliability criteria set forth in PJM Manual 18 (See www.pjm.com), as it may change from time to time. The Capacity Payment, if and as applicable, will be equal to the capacity revenues that the Company receives from PJM for selling such capacity into the Reliability Pricing Model (RPM) capacity auction prior to delivery, adjusted for all other PJM penalties and charges assessed to the Company by PJM arising from, among other things, non-performance or unavailability of the QF installation. QF installations requesting capacity payments must execute an agreement with the Company authorizing the Company to offer such capacity into the PJM market, including terms and conditions of such sale, and including any required security. Any losses experienced by the Company resulting from a QF installation's failure to perform shall be recovered under its Non-utility Generation Charge.

Energy Payment and Capacity Payment, if any, net of Service Charge, shall be determined monthly on an after-the-fact basis, and made within 90 days of the QF meter reading date.

METERING COSTS: QF customers shall pay all metering equipment and related costs as required by the Company and/or by PJM.

INTERCONNECTION COSTS: QF customers shall pay interconnection costs (see Part II, Section 4.05) and any line extension costs required to interconnect the QF to the Company's facilities.

Rider QFS
Cogeneration and Small Power Production Service

LIMITATION ON ENERGY PURCHASES: The Company may refuse to purchase energy from a QF when:

(a) The Company's distribution or transmission circuits are loaded to capacity and further energy would cause an overload. Such refusal to purchase may occur on an instantaneous basis.

(b) An emergency occurs on that part of the Company's system interconnected with the QF such that there would be no means of delivering the energy to the remainder of the Company's system. Such refusal to purchase may also occur on an instantaneous basis.

(c) Customer has failed to provide documentation of QF certification with F.E.R.C. as required by the Company.

(d) Customer has an account arrearage.

Rider STB
Standby Service
(Applicable to Service Classifications GS, GST, GP and GT)

AVAILABILITY: Rider STB specifies the conditions under which customers with qualifying cogeneration or small power production facilities may obtain Standby Service under this Rider when such facilities are used to meet the customer's load requirements. The terms of this Rider shall not be available in any month, however, when the customer's Generation Availability (GA) for the current month does not exceed 50%.

STANDBY DEMAND CHARGE: The terms of this Rider: (1) modify the Determination of Demand and waive the Minimum Demand Charge of the applicable service classification; and (2) impose a Standby Demand Charge determined in accordance with the following calculations and definitions:

SDC=>[(DR*BD)+(SR*<MM or AG)] or [SR*CD]

Which means that the Standby Demand Charge is equal to the greater of:
(1) DR times BD, plus SR times lesser of MM or AG; or
(2) SR times CD

DEFINITIONS:

BD = Billing Demand KW
= >[MM - AG] or [0]
Which means that the Billing Demand is equal to MM - AG, but not less than zero

MM = Maximum Monthly facility on-peak KW load
Which is the maximum coincident 15-minute on-peak load supplied by the Customer's generation plus (or minus) the load delivered by (or furnished to) the Company.

AG = Annual Average Generation on-peak
= Current and preceding eleven months average of [on-peak KWH produced / (260 hours - SM)]
Which means taking the average of each monthly on-peak Average Generation from the current and preceding eleven months. Average Generation is calculated by taking the monthly on-peak KWH produced / (260 hours – SM)

DR = Demand Rate per KW of applicable service classification

JERSEY CENTRAL POWER & LIGHT COMPANY

1st Rev. Sheet No. 59

BPU No. 13 ELECTRIC - PART III

Superseding Original Sheet No. 59

Rider STB
Standby Service
(Applicable to Service Classifications GS, GST, GP and GT)

SR = Standby Rate per KW (including SUT)
= **$3.65** for Service Classifications GS & GST
= **$2.23** for Service Classifications GP
= **$1.07** for Service Classifications GT

CR = Capacity Rating of generation facility

CD = Contract Demand
= <[CR] or [>(estimated MM) or (>MM most recent 12 months)]
Which means that the Contract Demand is equal to the lesser of:
(1) CR; or
(2) the greater of: (a) estimated MM; or (b) highest MM of most recent 12 months

GA = Generation Availability
= AG / CD

SM = Scheduled maintenance hours
Applicable only for customers receiving service under this rider as of February 25, 1993. The number of such hours may be reduced up to the amount of mutually agreed upon scheduled maintenance hours, but are not to exceed the amount actually incurred. A maximum of two 2-week periods may be allowed per year during the billing months of April, May, June, October, November or December and must be scheduled 6-months in advance. Each maintenance period may occur only during a single billing period.

260 hours = Average monthly on-peak hours
= 52 weeks x 5 days x 12 on-peak hours ÷12 months

Rider CEP
Consumer Electronics Protection Service

RESTRICTION: This Rider is closed to new enrollment as of March 3, 1999.

AVAILABILITY: Rider CEP had been available for customers which desire that the Company provide protection from power fluctuations, surges and other power disturbances. Service under this Rider is restricted to service entrance and equipment compatibility.

A single meter socket surge suppression device is necessary on the service entrance supplying power to the premises to protect internal wiring against major power line spikes and surges. Electrical receptacle outlet surge suppressors are available for receptacles within the customer's premise. Such receptacle outlet suppressors provide protection against surges to more sensitive electronics, and are only available when a meter socket surge suppression device is installed. Uninterruptible power supply units are available for use with individual electronic equipment.

MONTHLY CHARGES:	Including SUT	Excluding SUT
Meter socket surge suppression device - single phase:	**$2.93**	**$2.75**
Meter socket surge suppression device - three phase:	**$5.33**	**$5.00**
Electrical receptacle outlet surge suppressor - 2 outlet:	**$0.64**	**$0.60**
Electrical receptacle outlet surge suppressor - 4 outlet:	**$0.80**	**$0.75**
Uninterruptible power supply unit - 0.75 KVA:	**$21.33**	**$20.00**
Uninterruptible power supply unit - 1.00 KVA:	**$26.66**	**$25.00**
Uninterruptible power supply unit - 1.50 KVA:	**$31.99**	**$30.00**

TERM OF CONTRACT:
A one-year term of contract is required, renewable thereafter on a month-to-month basis.

TERMS OF PAYMENT:
Charges applicable under this Rider will be rendered on the customer's bill for electric service. Such bills are due when rendered and become overdue when payment is not received by the Company on or before the due date specified on the bill. Overdue bills thereafter may become subject to a late payment charge as described in Section 3.19, Part II.

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Rider CEP
Consumer Electronics Protection Service

TERMS AND CONDITIONS:

1) The Company will install and remove the meter socket surge suppressor device and deliver the electrical receptacle outlet surge suppressors and/or Uninterruptible power supply equipment to the customer.

2) Customers utilizing CEP service provided under this Rider shall contact the Company in order to arrange the return of such equipment to the Company, upon termination of this Service, in the manner specified by the Company. Customers failing to arrange to return such equipment to the Company, shall be required to pay a charge equivalent to the Company's current replacement cost for such equipment.

3) The Company shall not be liable for any damage or injury arising from the improper use of equipment supplied under this Rider or for any costs or damages attributable to the loss of the customer's business, production or facilities resulting from the failure of such equipment.

4) The Company will provide the applicable manufacturer's warranty associated with the meter socket surge suppressor device and/or electrical receptacle outlet surge suppressor.

5) Disconnection and subsequent reconnection of Consumer Electronics Protection Service at the same location shall be unavailable as of March 3, 1999. However, if a customer transfers service from one location to another location within the Company's service areas, the customer may transfer the CEP service to the new location.

JERSEY CENTRAL POWER & LIGHT COMPANY

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Rider CBT
Corporation Business Tax

APPLICABILITY: In accordance with P.L. 1997, c. 162 (the "energy tax reform statute"), provision for the New Jersey Corporation Business Tax (CBT) as it applies to non-production related revenues has been included in all rate schedules. The energy tax reform statute exempts the following customers from the CBT provision, and when billed to such customers, the rates otherwise applicable under this tariff shall be reduced by the provision for the CBT (and related New Jersey Sales and Use Tax) included therein:

1. Franchised providers of utility services (gas, electricity, water, waste water and telecommunications services provided by local exchange carriers) within the State of New Jersey.

2. Cogenerators in operation, or which have filed an application for an operating permit or a construction permit and a certificate of operation in order to comply with air quality standards under P.L 1954, c. 212 (C.26:2C-1 et seq.) with the New Jersey Department of Environmental Protection, on or before March 10, 1997.

3. Special contract customers for whom a customer-specific tax classification was approved by a written Order of the New Jersey Board of Public Utilities prior to January 1, 1998.

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 13 ELECTRIC - PART III **Original Sheet No. 63**

Rider SUT
Sales and Use Tax

APPLICABILITY: In accordance with P.L. 1997, c. 162 (the "energy tax reform statute"), as amended by P.L. 2016, c. 57, provision for the New Jersey Sales and Use Tax ("SUT") has been included in all charges applicable under this tariff by multiplying the charges that would apply before application of the SUT by the factor 1.06625.

A. The energy tax reform statute exempts the following customers from the SUT provision, and when billed to such customers, the charges otherwise applicable under this tariff shall be reduced by the provision for the SUT included therein:

1. Franchised providers of utility services (gas, electricity, water, waste water and telecommunications services provided by local exchange carriers) within the State of New Jersey.
2. Cogenerators in operation, or which have filed an application for an operating permit or a construction permit and a certificate of operation in order to comply with air quality standards under P.L 1954, c. 212 (C.26:2C-1 et seq.) with the New Jersey Department of Environmental Protection, on or before March 10, 1997.
3. Special contract customers for which a customer-specific tax classification was approved by a written Order of the New Jersey Board of Public Utilities prior to January 1, 1998.
4. Agencies or instrumentalities of the federal government.
5. International organizations of which the United States of America is a member.

B. The Business Retention and Relocation Assistance Act (P.L. 2004, c. 65) and subsequent amendment (P.L. 2005, c. 374) exempts the following customers from the SUT provision, and when billed to such customers, the charges otherwise applicable shall be reduced by the provision for the SUT included therein:

1. A qualified business that employs at least 250 people within an enterprise zone, at least 50% of whom are directly employed in a manufacturing process, for the exclusive use or consumption of such business within an enterprise zone, and
2. A group of two or more persons: (a) each of which is a qualified business that are all located within a single redevelopment area adopted pursuant to the “Local Redevelopment and Housing Law,” P.L.1992, c.79 (C.40A:12A-1 et seq.); (b) that collectively employ at least 250 people within an enterprise zone, at least 50% of whom are directly employed in a manufacturing process; (c) are each engaged in a vertically integrated business, evidenced by the manufacture and distribution of a product or family of products that, when taken together, are primarily used, packaged and sold as a single product; and (d) collectively use the energy and utility service for the exclusive use or consumption of each of the persons that comprise a group within an enterprise zone.
3. A business facility located within a county that is designated for the 50% tax exemption under section 1 of P.L. 1993, c. 373 (C.54:32B-8.45) provided that the business certifies that it employs at least 50 people at that facility, at least 50% of whom are directly employed in a manufacturing process, and provided that the energy and utility services are consumed exclusively at that facility.

A business that meets the requirements in B.1., B.2. or B.3. above shall not be provided the exemption described in this section until it has complied with such requirements for obtaining the exemption as may be provided pursuant to P.L.1983, c.303 (C.52:27H-60 et seq.) and P.L.1966, c.30 (C.54:32B-1 et seq.) and the Company has received a sales tax exemption letter issued by the New Jersey Department of Treasury, Division of Taxation.

Rider RRC
RGGI Recovery Charge

APPLICABILITY: Rider RRC provides a charge for the costs associated with demand response/energy efficiency/renewable energy programs directed by the BPU as detailed below. The RGGI Recovery Charge (RRC) is applicable to all KWH usage of any Full Service Customer or Delivery Service Customer, as follows

For service rendered effective January 1, 2023:

RRC = $0.001451 per KWH ($0.001547 per KWH including SUT)

The above RRC provides recovery for the followings:

Solar Renewable Energy Certificates Financing Program (SREC I & II)

Pursuant to BPU Orders dated March 27, 2009 and September 16, 2009 (Docket No. EO08090840) approving an SREC-based financing program (SREC I), pursuant to BPU Order dated December 18, 2013 (Docket No. EO12080750) approving the SREC II, and pursuant to BPU Order dated December 20, 2019 (Docket No. ER19070806) approving the Stipulation of Settlement, the Company shall include an SREC I & II Rate of **$(0.000152)** per kWh (**$(0.000162)** per kWh including SUT) in RRC effective January 1, 2023.

Transition Renewable Energy Certificate Incentive Program (TREC Program)

On December 6, 2019, the Board issued an Order in Docket No. QO19010068 ("December 6, 2019 Order"), establishing a transition renewable energy certificate ("TREC") program to be implemented upon the attainment of 5.1% of the retail electric sales in the State being from solar. Solar projects that become operational after the State's attainment of the 5.1% milestone but prior to the implementation of a successor solar program will be eligible to participate in the TREC Program, as determined by the Board. The December 6, 2019 Order required the New Jersey Electric Distribution Companies ("EDCs") to purchase all TRECs generated and authorized the EDCs to recover their reasonable and prudent costs incurred for the purchase of TRECs and the fees charged by a TREC Administrator (generally, "TREC Program Costs"). The December 6, 2019 Order further provided that "[r]ecovery shall be based on each EDC's proportionate share of retail electric sales."

The TREC Rate recovers JCP&L's proportional share of TREC Program Costs, including, but not limited to, those costs associated with the purchase of TRECs, fees charged by the TREC Administrator, and any additional costs or expenses incurred by JCP&L as a result of the Company's participation in or implementation of the TREC program.

The TREC Rate for all customer classes is **$0.001068** per kWh (**$0.001139** per kWh including SUT), effective January 1, 2023.

Solar Successor Incentive Program (SuSI Program)

On July 28, 2021, the Board issued an order establishing the Solar Successor Incentive ("SuSI") program ("SuSI Order") pursuant to the New Jersey Clean Energy Act and the Solar Act of 2021. The SuSI Order established a new renewable energy certificate, SREC-IIs, and required that the New Jersey Electric Distribution Companies ("EDCs") purchase all SREC-IIs generated and authorized the EDCs to recover their reasonable and prudent costs for SREC-II procurement and SREC-II Administrator fees (generally, "SuSI Program Costs"). The SuSI Order further provided that "[r]ecovery shall be based on each EDC's proportionate share of retail electric sales."

The SuSI Rate recovers JCP&L's proportional share of SuSI Program Costs, including, but not limited to, those costs associated with the purchase of SREC-IIs, fees charged by the SREC-II Administrator, and any additional costs or expenses incurred by JCP&L as a result of the Company's participation in or implementation of the SuSI program.

The SuSI Rate for all customer classes is **$0.000079**/kWh (**$0.000084**/kWh including SUT), effective January 1, 2023.

JERSEY CENTRAL POWER & LIGHT COMPANY

1st Rev. Sheet No. 64a

BPU No. 13 ELECTRIC - PART III

Superseding Original Sheet No. 64a

Rider RRC
RGGI Recovery Charge

Energy Efficiency and Conservation Program (EE&C)

Pursuant to the BPU Order dated June 10, 2020 directing New Jersey's electric and natural gas companies to establish programs that reduce the use of electricity and natural gas within their territories and the BPU Order dated April 27, 2021 approving the Stipulation of Settlement, the Company shall include a EE&C Charge in RRC effective July 1, 2021. The EE&C Charge provides for recovery of revenue requirements associated with Energy Efficiency and Peak Demand Reduction Programs as approved by the BPU.

Effective January 1, 2023, EE&C rate for service classification is as follows:

EE&C = $0.000456 per KWH ($0.000486 per KWH including SUT)

The Company will submit to the BPU annually an application to recover the revenue requirements for the forthcoming Program Year starting July 1st of each year and ending June 30th of the following year. Pursuant to the BPU Order at Docket Nos. QO1901040, QO19060748 & QO17091004, the revenue requirements will include a return of and on EE&C program investments and a reconciliation of actual revenues with actual costs on an annual basis.

The RRC costs shall accrue interest on any over or under recovered balances of such costs at the interest rate based on a two-year constant maturity Treasuries as published in the Federal Reserve Statistical Release on the first day of each month (or the closest day thereafter on which rates are published), plus sixty basis points, but shall not exceed the Company's overall rate of return as approved by the BPU. Such interest rate shall be reset each month. The interest calculation shall be based on the net of tax beginning and end average monthly balance, consistent with the methodology in the Board's Final Order dated May 17, 2004 (Docket No. ER02080506 et al.), compounded annually (added to the balance on which interest is accrued annually) on January 1 of each year.

The Company will make annual filings to true-up the RRC on or before February 1 of each calendar year and will request rate changes, if any, to be implemented on July 1 of the filing year.

3rd Rev. Sheet No. 65
BPU No. 13 ELECTRIC - PART III Superseding 2nd Rev. Sheet No. 65

Rider ZEC
Zero Emission Certificate Recovery Charge

APPLICABILITY: The Zero Emission Certificate Recovery Chare ("Rider ZEC" or "ZEC Charge") provides a charge for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board") as detailed below. The ZEC Charge is applicable to all kWh usage of any Full Service Customer or Delivery Service Customer.

Per KWH		Including SUT
ZEC Charge	$0.004000	$0.004265
ZEC Reconciliation Charge	($0.000089)	($0.000095)
Total ZEC Charge	**$0.003911**	**$0.004170**

Pursuant to the BPU's Zero Emission Certificate Charge Order dated November 19, 2018 in Docket No. EO18091002, the Board approved the implementation of a non-bypassable, irrevocable ZEC Charge of $0.004000 per KWH for all customers. The ZEC Charge reflects the emission avoidance benefits of the continued operation of selected nuclear plants as determined in L. 2018, c.16 (the "ZEC Law"). The ZEC Charge has been set at the rate specified in the ZEC Law and may be adjusted periodically by the Board, in accordance with the methodology provided for in the ZEC law.

In accordance with the ZEC Law, the proceeds of the ZEC Charge will be placed in a separate account, which amount the Company may use for general corporate purposes, with interest applied at the Company's short-term borrowing rate as calculated each month, and will be used solely to purchase ZECs and to reimburse the Board for its reasonable, verifiable costs incurred to implement the ZEC program. Refunds will be provided to the customers served under each of the Company's rate schedules in proportion to the ZEC Charge revenues contributed by the rate schedule.

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 13 ELECTRIC - PART III **Original Sheet No. 66**

Rider TAA
Tax Act Adjustment

APPLICABILITY: Rider TAA provides a credit resulting from the amortization and reconciliation of certain Excess Deferred Income Taxes ("EDIT"), including applicable carrying charges related to the impact of the Federal Tax Cuts and Jobs Act of 2017 ("Tax Act") on the Company's rates.

Effective **May 15, 2019**, the following TAA credits, including one time bill credit, (including Sales and Use Tax as provided in Rider SUT) will be applicable to all KWH usage of any Full Service Customer or Delivery Service Customer under Service Classification:

RS	**$0.006389 per KWH**
RT/RGT	**$0.006103 per KWH**
GS	**$0.005116 per KWH**
GST	**$0.003950 per KWH**
GP	**$0.002782 per KWH**
GT	**$0.001632 per KWH**
Lighting	**$0.027344 per KWH**

(includes OL, SVL, MVL, ISL and LED)

Effective **June 15, 2019**, the following TAA credits (including Sales and Use Tax as provided in Rider SUT) will be applicable to all KWH usage of any Full Service Customer or Delivery Service Customer under Service Classification:

RS	**$0.000310 per KWH**
RT/RGT	**$0.000307 per KWH**
GS	**$0.000274 per KWH**
GST	**$0.000213 per KWH**
GP	**$0.000154 per KWH**
GT	**$0.000093 per KWH**
Lighting	**$0.001567 per KWH**

(includes OL, SVL, MVL, ISL and LED)

Carrying Charges: Interest should not accrue on the outstanding net unprotected EDIT liability. No interest charges apply to over or under-recovered balances.

1st Rev. Sheet No. 67
BPU No. 13 ELECTRIC - PART III Superseding Original Sheet No. 67

Rider RP
JCP&L Reliability Plus Charge

APPLICABILITY: Rider RP provides for full and timely recovery of revenue requirements associated with reliability infrastructure investment projects subject to the Infrastructure Investment and Recovery regulations pursuant to N.J.A.C. 14:3-2A.1 *et seq.* and as approved by the BPU Order dated May 8, 2019 in Docket No. EO18070728.

The JCP&L Reliability Plus (RP) Charge is applicable to Service Classifications RS (Residential Service), RT (Residential Time-of-Day), RGT (Residential Geothermal & Heat Pump), GS (General Service Secondary), GST (General Service Secondary Time-of-Day), GP (General Service Primary), GT (General Service Transmission), OL (Outdoor Lighting), SVL (Sodium Vapor Street Lighting), MVL (Mercury Vapor Street Lighting), ISL (Incandescent Street Lighting) and LED (LED Street Lighting) and for all usage (KWH, KW or per Fixture) of any Full Service Customer or Delivery Service Customer, as follows:

Service Classification	RP Charge (Including SUT)	
RS	$0.000000	per KWH
RT/RGT	$0.000000	per KWH
GS	$0.000000	per KWH
GST	$0.00	per KW
GP	$0.00	per KW
GT	$0.00	per KW
Lighting (OL, SVL, MVL, SVL and LED)	$0.00	per Fixture

The Company will make periodic filings to reset the RP Charges. The initial recovery period will include actual capital investments with in-service dates between June 1, 2019 and November 30, 2019 and will be filed no later than September 15, 2019 with an effective date on or before March 1, 2020. All subsequent filings will adhere to the Company's recovery periods as approved in the above referenced BPU Order and in accordance with N.J.A.C. 14:3-2A.1 *et seq.*

BPU No. 13 ELECTRIC - PART III **Original Sheet No. 68**

Rider LRAM
JCP&L Lost Revenue Adjustment Mechanism Charge

APPLICABILITY: The Lost Revenue Adjustment Mechanism Charge ("Rider LRAM" or "LRAM Charge") provides for recovery of the revenue impact of sales losses demonstrated to have resulted from the Company's Energy Efficiency and Peak Demand Reduction Programs, subject to regulations pursuant to N.J.S.A. 48:3-98. 1(a)(1) and as approved by the BPU Order.

The JCP&L LRAM Charge is applicable to Service Classifications RS (Residential Service), RT (Residential Time-of-Day), RGT (Residential Geothermal & Heat Pump), GS (General Service Secondary), GST (General Service Secondary Time-of-Day), GP (General Service Primary), GT (General Service Transmission), OL (Outdoor Lighting), SVL (Sodium Vapor Street Lighting), MVL (Mercury Vapor Street Lighting), ISL (Incandescent Street Lighting) and LED (LED Street Lighting) and for all usage (KWH and KW) of any Full Service Customer or Delivery Service Customer, as follows:

LRAM Charge effective July 1, 2021

Service Classification	LRAM Charge (Including SUT)	
RS	$0.000000	per KWH
RT/RGT	$0.000000	per KWH
GS	$0.000000	per KWH
GST	$0.00	per KW
GP	$0.00	per KW
GT	$0.00	per KW
Lighting (OL, SVL, MVL, SVL and LED)	$0.000000	per KWH

The Company will submit to the BPU by August 31st of each year, starting August 31, 2022, to recover the lost distribution revenue the Company's Energy Efficiency and Peak Demand Reduction Programs for the preceding year ended June 30th. The lost distribution revenue in each filing will be considered verified once the underlying energy savings have been verified through the Evaluation Measurement & Verification process undertaken by the Company's independent evaluator, subject to BPU review. Within each rate filing, there will be a reconciliation of actual revenues received with projected revenues, including carrying costs, through the end of February of each year. Any adjustment of the amount of savings used to determine lost revenue recovery resulting from the verification process, but not completed by the time of filing, will be included in the following year's reconciliation. The applicable carrying cost is calculated on a monthly basis at an interest rate equal to the rate on two-year constant maturity Treasuries, as show in the Federal Reserve Statistical Release on or closest to January 1 of each year, plus sixty basis points, compounded annually as of January 1 of each year. All subsequent filings will adhere to the Company's recovery periods as approved in the above referenced BPU Order.

Rider EV
ELECTRIC VEHICLE CHARGER RIDER

The EV Driven Program ("Program") is comprised of four (4) subprograms to incentivize EV adoption throughout the JCP&L service territory, and thereby to support the attainment of the State's goals for EV adoption and the reduction of greenhouse gas ("GHG") emissions. These subprograms include: 1) Residential Customer Sub-program; 2) Mixed-Use Commercial Sub-program; 3) Direct Current ("DC") Fast Charger ("DCFC") Public Charging Subprogram; and 4) Consumer Education and Outreach initiative. All Program incentives and Program initiatives contained within this rider are subject to the Terms established by JCP&L, available at http://www.jcp-l.com/evdriven, and are subject to modification by the Company.

The Program will commence on July 15, 2022 and will terminate on July 15, 2026, or earlier if the budgeted funds for the Program, or any individual subprogram, are exhausted. The Company does reserve the right to extend the Program with BPU approval.

1) Electric Vehicle Charger Off-Peak Credit

APPLICABILITY: Available to new and existing Residential and Multi-Family Customers being served on Service Classification RS, RST, RGT, GS who install a Company-qualified smart Electric Vehicle ("EV") Level 2 ("L2") charger ("Eligible Customer"). This provision within Rider EV is voluntary and offers qualified customers the opportunity to receive a bill credit by charging an EV battery with a Company-qualified smart EV L2 charger during Off-Peak hours. Customers must agree to share and communicate the charging data from their smart EV L2 charger via remote access with the Company to receive the bill credit. Customers are not required to receive their generation supply through Basic Generation Service to be eligible for this Rider. This Rider is limited to 2,000 eligible residential and 75 eligible multi-family Customers on a first-come, first-serve basis. Only customers whose application is accepted by the Company will receive the Off-Peak Credit.

RATE: Eligible Customers that qualify for this provision within this Rider will receive a credit of 2 cents per Kilowatt-hour ("kWh") for Net Off-Peak kWh Usage at their smart EV L2 charger. Net Off-Peak kWh Usage is calculated as kWh usage recorded by the Customer's smart EV Level 2 charger during Off-Peak hours less kWh usage recorded by the Customer's smart EV L2 charger during On-Peak hours. Net Off-Peak kWh Usage must be a positive value for the Customer to receive a credit. In the event Off-Peak kWh less On-Peak kWh is less than zero, the Net Off-Peak kWh Usage shall be considered zero for the measurement period. JCP&L will provide the on-bill credits[1] to residential customers on a quarterly basis, which bill credits will terminate when the budget has been exhausted or the Program has terminated. Quarterly off-peak bill credits for eligible non-residential customers will be paid via off-bill credit.

On-Peak hours are Monday through Friday from 6:00 AM to 11:00 PM, Eastern Standard Time. All other hours including weekend hours will be considered off-peak. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change. The Company may also selectively stagger the on-peak hours up to one hour in either direction when required to alleviate local distribution system peaking within high-density areas. The off-peak hours will not, however, be less than 7 hours daily.

TERM: Month to month basis. This provision within this Rider will be available until the earlier of the Company modifying the Off-Peak Credit program or July 15, 2026.

[1] Customer credits will accrue until such time as on-bill credit functionality is fully deployed by the Company. Payment of a customer's accrued credits will occur after full deployment of on-bill credit functionality by the Company.

Rider EV (CONT.)
ELECTRIC VEHICLE CHARGER RIDER

2) Customer Make-Ready Incentive:

APPLICABILITY: Provides incentives for the Make-Ready Work on the customer-side of the meter necessary to enable the installation of a Company-qualified EV Charger. The available make-ready incentives do not include the cost of the charger. Available to all Eligible Customers located in the territory served by the Company. Eligible Customers must install a Company-qualified EV L2 charger or Direct Current Fast Charger ("DCFC"), subject to the limitations outlined below and the Program Terms established by the Company and available at www.jcp-l.com/evdriven.

The Company will provide an incentive to Customers served under Schedule RS, RT, RGT, GS, GST, GP, and GT who install a Company-qualified smart EV Level 2 charger or DCFC after the commencement date of the Program. The smart EV L2 charger or DCFC must be connected after the Company meter and must be owned by the Customer receiving the incentive. The smart EV L2 charger for other than residential and multi-family applications and DCFC applications must be publicly-accessible charging ports. In accordance with Board's Order approving the Program in BPU Docket No. EO21030630, "publicly-accessible charging" means a charger located on public land, a community location, or travel corridor. Such chargers are owned and operated by site owner, property manager or management company, EVSE Infrastructure Company, or, in limited cases, an EDC, that is accessible to the public 24 hours a day, seven days a week; however, generic parking restrictions or requirements, such as in a commercial garage, or emergency restrictions, including construction, street cleaning, etc., are not applicable. Such chargers may charge the EV owner a fee for charging; such fees will be clearly displayed to the user. Customers are not required to receive their generation supply through Basic Generation Service to be eligible for the incentive. A list of qualifying smart EV L2 chargers is available on the Company's website at www.jcp-l.com/evdriven.

In order to qualify for the Company incentive, the Customer must submit an application with all necessary supporting documentation within 30 days of installation (including copies of receipts and/or invoices of the smart EV L2 charger or DCFC purchase and installation costs) and agree to share and communicate the charging data from the smart EV L2 charger or DCFC with the Company. The Customer is responsible for maintenance and enabling the smart capabilities of the EV L2 charger or DCFC. Once the Company receives the Customer's completed application and confirms that the Customer's smart EV L2 charger or DCFC has been installed and is available for service and capable of remote communication, and approves the application, the Company shall issue the applicable incentive. The program only applies to eligible smart EV L2 chargers and DCFCs installed on or after July 15, 2022. Customer Make-Ready Incentives will be paid in an amount, not to exceed the amount stated in the table below for new service to EV chargers for each subprogram, based on the actual documented cost of the make-ready work, excluding the cost of the charger:

Sub-Program	Customer Make-Ready Incentive (up to $ amount)
Residential Customer Sub-program	$1,500
Public/Community based Component	$6,700
Workplace Component	$5,000
Multi-family Component	$6,700
Multi-family in Overburdened Communities	$8,375
DCFC Public Charging Sub-Program	$25,000

Rider EV (CONT.)
ELECTRIC VEHICLE CHARGER RIDER

3) Utility Make-Ready Work:

All applicants must advance the cost of any Utility Make-Ready Work to ensure that: 1) the utility service is adequate to support EV charging; 2) any service upgrade is for the purpose of supporting EV charging; and 3) the customer follows through with the charger installation. The Company will be responsible for any utility upgrades to its facilities necessary to meet the adequate character and capacity of its electric service requirements to the Customer at the Company's reasonable discretion and subject to the BPU's notification and approval requirements. Utility Make-Ready Incentives for new service to EV chargers for each Sub-program will be paid in an amount, not to exceed the amount stated in the table below for each subprogram, based on the actual cost of the Utility Make-Ready Work.

Sub-Program	Amount of Utility Make Ready Incentive (up to $ amount)
Residential Customer Sub-program	$5,500
Public/Community based Component	$11,100
Workplace Component	$11,100
Multi-family Component	$11,100
DCFC Public Charging Sub-Program	$50,500

4) Multifamily EV Charging Residential Parity Rate

AVAILABILITY: Available to new and existing all Company-qualified Level 2 Electric Vehicle Charging Stations located at Multifamily Dwellings ("Multifamily Level 2 Electric Vehicle Charging Station") at a separately metered premise from the metering at the multifamily complex.

RATE: Electric service shall be billed at a rate equivalent to that which would be billed under the Service Classification RS – Residential Service, pursuant to the BPU Order in Docket QO20050357**.**

TERM: Month to month basis. This provision will be available until July 15, 2026, or earlier if the budgeted funds for the Program, or any individual subprogram, are exhausted.

5) DCFC Public Charging Subprogram - Distribution Demand Charge Discount

AVAILABILITY: Available to new and existing customers participating in the DCFC Public Charging Sub-Program of JCP&L's BPU-approved EV Driven Program. Such customers will be eligible for a kW distribution demand charge discount related to the DCFC EV charging ports, which will be separately metered from other electric load at the site, and served on Rate Classification GS, GST, GP, or GT.

RATE: The discount will be provided for the distribution demand charge portion of the bill and will be provided as an off-bill payment on a quarterly basis. The kW distribution demand charge discount will be as follows for each program year:

Program Year	% Discount
1	50%
2	50%
3	25%
4	25%

Program Year is defined as the date of initial implementation for 12 months. All bill credits will be terminated when the EV Driven Budget for Demand Charge discount has been exhausted or the Program has been terminated, whichever comes first.

TERM: Month to month basis. This provision will be available until the budget has been exhausted or the Program has terminated, whichever occurs first.

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU NO. 14 ELECTRIC ORIGINAL TITLE SHEET

TARIFF for SERVICE

Part I

General Information

Part II

Standard Terms and Conditions

Issued: **Effective:**

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Docket No. dated

Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 14 ELECTRIC - PART I Original Sheet No. 1

PART I
GENERAL INFORMATION
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300 Madison Avenue, Morristown, NJ 07962-1911

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 14 ELECTRIC - PART I Original Sheet No. 2

General Information

A - Service Tariff: This tariff for Service ("Tariff") of Jersey Central Power & Light Company, ("Company"), is filed with the Board of Public Utilities of New Jersey ("BPU") pursuant to NJAC 14:3-1.3. The Standard Terms and Conditions set forth in Part II of this Tariff state the conditions under which Service is rendered, and govern the Company's provision of Full Service, Delivery Service and/or other Services to the extent applicable. The Service Classifications and Riders contained in Part III of this Tariff state the basis for computing the charges to Customers for Service. Except where specifically modified by written contract, all applicable provisions of this Tariff constitute, or are a part of, each service contract, express or implied, and both the Customer and the Company shall be bound thereby.

B - Revision of Tariff: The Company may at any time, and in any manner permitted by law and the applicable rules and regulations of the BPU, supplement, terminate, change, or modify this Tariff or any part thereof.

C - Exchange of Information: The Company will, at the Customer's request, explain the provisions of its Tariff and inform the Customer as to the conditions under which Service can be obtained from the Company's system. It is the responsibility of the Customer or his agent, before making his initial electrical installation or planning material changes in an existing installation, to obtain from the Company information regarding the characteristics of available Service, its designation of the point of attachment of the service connection and meter location, and such other information as may be necessary to assure that the Customer's installation will be compatible with the facilities and Service the Company will supply.

D - Statements by Agents: No representative of the Company has authority to modify any provision contained in this Tariff or bind the Company by any promise or representation contrary thereto.

E - Agreements and Contracts: Standard agreements to provide Service shall be in accordance with Parts II and III of this Tariff. As a condition for establishing, continuing, or resuming the provision of Service in a situation where the Company incurs or will incur greater than normal investment cost or operating expense in order to meet the Customer's special or unusual Service requirements, or to protect the Company's system from undue disturbance of voltage regulation or other adverse effects, and in order to avoid undue discrimination, the Company may require an agreement for a longer term than specified in the applicable Service Classification, may require a contribution in aid of construction and may establish such minimum charges and facilities charges as may be equitable under the circumstances.

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 13 ELECTRIC - PART I Original Sheet No. 3

General Information

F – Definitions: The following terms are herein defined for general reference to assist in their application in Parts II and III of this Tariff.

(1) Alternative Electric Supplier: Any person, corporation or other entity, other than the Company, that has applied for and received an electric power supplier license from the BPU.

(2) Applicant: Any person, corporation or other entity that (a) desires to receive from the Company electric generation or any other Service provided for in this Tariff, (b) complies completely with all Company requirements for obtaining electric generation or any other Service provided for in this Tariff, (c) has filed and is awaiting Company approval of its application for Service, and (d) is not yet actually receiving from the Company any Service provided for in this Tariff. An Applicant shall become a Customer for purposes of this Tariff only after it actually starts receiving the applicable Service from the Company under this Tariff.

(3) Beneficiary: The person, corporation or the entity financially benefiting from the service.

(4) Billing Month: Generally, that calendar month in which the majority of the Company's meters are read for the purpose of establishing the electric service usage of Customers for their prior 26 to 35 day period.

(5) Connected Load: The sum of the input ratings of all electric-using devices located on the Customer's premises and which are or can be, by the insertion of a fuse, closing of a switch, or any similar method, connected simultaneously to the Company's Service. Although the manufacturer's nameplate rating may be used to determine the input rating of any particular device, the Company may instead determine the input rating of any device by test.

(6) Contract Capacity: That electrical capacity which the Customer specifies is needed to supply the Customer's requirements for Service and which the Company agrees to furnish through either Full Service or Delivery Service.

(7) Contract Location: Each metering point shall be considered a contract location and shall be metered and billed under a separate service contract. In cases where unmetered service is provided, the Point of Delivery shall be considered a contract location.

(8) Customer: Any person, partnership, association, corporation, or agency of municipal, county, state, or federal government receiving any Service rendered by the Company under this Tariff at a Contract Location. The term "Customer" shall also include Applicant when, in the Company's opinion, the specific provision of this Tariff was intended to be so inclusive. Any customer receiving Delivery Service shall simultaneously be a customer of an Alternative Electric Supplier.

(9) Delivery Service: The provision of electric distribution and other services by the Company to Customers under this Tariff who purchase their electric generation service from Alternative Electric Suppliers.

General Information

(10) End User: A person who receives, uses or consumes service. An end user may or may not be a customer as defined herein.

(11) Full Service: The provision of electric distribution and other services by the Company to Customers under this Tariff who purchase their electric generation service from the Company.

(12) Line Extension: This term applies to those overhead or underground facilities for the distribution or transmission of electrical energy to serve new Customers or the enlarged load of existing Customers which are constructed by the Company as a specific project (a) on a public highway and/or (b) on a right-of-way over private or public land to serve one or more Customers. Such an extension may be an addition to and/or upgrade of existing facilities or a new installation of facilities. A line extension originates at the pole or point at which it is connected to the existing facilities or where such upgraded facilities are required and it extends to and includes (a) the most remote pole or point from which a "Service Drop" or "Underground Service Connection" is installed, or (b) to the point at which a "Service Lateral" originates.

(13) Point of Delivery: The point at which the Customer receives Service and from which point inward, with respect to the premises served, the Customer assumes responsibility and liability for the presence or use of electricity in the Customer's installation.

(14) Residence: A structure or portion of a structure intended for use as sleeping quarters by a person or persons, and containing cooking and sanitary facilities.

Auxiliary Residential Purposes: Electric loads used on the premises in conjunction with the operation, use, and maintenance of an individual Residence. Such loads may include yard lighting, swimming pool pumps and heaters, saunas, driveway heaters, household workshops, yard maintenance equipment, and garages or outbuildings when used in conjunction with the operation, use, or maintenance of the Residence.

Multiple Residential Structure: A structure containing more than one Residence and having no direct access between them except from the outside or a common hall.

Group Residential Structure: A structure containing a Residence and five or more sleeping quarters intended for rental purposes, and not qualifying as a Multiple Residential Structure.

Individual Residential Structure: A structure containing a Residence and not qualifying as a Multiple Residential Structure or a Group Residential Structure.

Incidental Non-Residential Purposes: Non-Residential loads totaling 10 kW or less and which are less than 30% of the Residential and/or Auxiliary Residential connected load it is metered with.

Non-Residential Purposes: Electric loads which do not qualify under "residential purposes" or "auxiliary residential purposes." Such loads shall include but are not limited to, ceramic kilns, electric welders, greenhouses, and loads used for farming, business, professional, avocation, or animal housing purposes.

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 14 ELECTRIC - PART I Original Sheet No. 5

General Information

(15) Service: The term "Service" (generally upper case), as used in this Tariff, references any electricity, or access to electricity, that is provided by the Company pursuant to this Tariff, or anything related to the provision of electricity, or access to electricity, provided or rendered by the Company pursuant to this Tariff. Note that the word "service" (generally lower case) is also used from time to time in this Tariff to reference services rendered by entities other than the Company (such as Alternative Electric Suppliers). The distinction between the Company's Services and other entities' services is apparent from the context, and the use of upper and lower case is intended to aid the reader in taking note of the distinction.

(16) Service Connection: The conductors and equipment for delivering Service from the Company's supply system to the service entrance on the customer's premises. If overhead, such Service Connection, also known as a "Service Drop," terminates at a fixture or fixtures installed on the Customer's building or structure at a location designated by the Company which will provide the required clearance of the Service Drop conductors with respect to intervening objects or surfaces. An underground Service Connection is the equivalent of the overhead Service Connection and terminates either at the Customer's over-current protective device on the inside of the first foundation wall adjacent to the street on which the Company's mains are situated or at the meter base installed as part of the “Service Entrance”. If the Company's primary or transmission delivery system is directly connected to the Customer's facilities, such as through transformation or circuit breaking facilities which constitute the service connection, the Point of Delivery shall be the point of connection between the Customer's facilities and the Company's facilities, which is usually identified in a written contract that provides for such direct connection. In other instances, the Point of Delivery is as specified in the definition of "Service Entrance."

(17) Service Drop: A Company-owned overhead Service Connection.

(18) Service Entrance or Entrance Facilities: In general, the conductors or accessory equipment by which electricity is carried from the Service Connection to the supply side of the devices protecting the Customer's circuits. If the Service Entrance is owned by the Customer, it is referred to as "Customer's Entrance Facilities" and the Point of Delivery is the junction of the Service Connection conductors with the Service Entrance. If the Service Entrance is owned by the Company, it is referred to as "Company's Service Entrance" and the Point of Delivery is at the supply side of the devices protecting the Customer's circuits. The metering devices are not included as part of the Service Entrance**.**

(19) Service Lateral: The electrical facilities constituting a branch from the Company's system, installed on private property to serve a single Customer. A Service Lateral may be either overhead or underground. If overhead, the Service Lateral originates at the pole or point at which connection is made to the existing system or line extension and extends to the pole or other aerial support where the Service Drop originates. When a secondary underground Service Lateral is owned, installed, and maintained by the Customer, it shall consist of the specified conduit and cable between its connection with the Company's system and the premises where the Service is to be used. A non-secondary overhead or underground Service Lateral may provide a circuit connection to Company-owned or Customer-owned transformers set in a vault or on a pad on the Customer's premises.

General Information

(20) Standby Service: Service that the Customer may receive or may request that the Company furnish in the event of a breakdown, shutdown, failure, or other impairment of a generator on the Customer's premises, from which the Customer normally receives all or a portion of his energy requirements.

(21) Summary Billing: A Service whereby the Company will add together the charges for multiple Full Service accounts maintained by one Customer and provide the Customer with a single bill.

(22) Tampering: Tampering shall mean connecting or causing to be connected by wire or any other device with the wires, cables or conductors of the Company, or connecting, disconnecting or shunting the meters, cables, conductors or other equipment of the Company, without the Company's permission. (See Part II, Sections 5.03, 6.04, 6.05, 6.06, 6.07, 6.08 and 7.03) (See N.J.S.A. 2C:20-8)

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 14 ELECTRIC - PART I Original Sheet No. 7

General Information

G - Municipalities Served: The following list designates those municipalities in which the Company serves the public through its distribution facilities.

BURLINGTON COUNTY

Chesterfield Twp.
New Hanover Twp.
North Hanover Twp.
Pemberton Boro
Pemberton Twp.
Southampton Twp.
Springfield Twp.
Woodland Twp.
Wrightstown Boro

ESSEX COUNTY
Livingston Twp.
Maplewood Twp.
Millburn Twp.

HUNTERDON COUNTY
Alexandria Twp.
Bethlehem Twp.
Bloomsbury Boro
Califon Boro
Clinton, Town of
Clinton Twp.
Delaware Twp.
East Amwell Twp.
Flemington Boro
Franklin Twp.
Frenchtown Boro
Glen Gardner Boro
Hampton Boro
High Bridge Boro
Holland Twp.
Kingwood Twp.
Lambertville, City of
Lebanon Boro
Lebanon Twp.
Milford Boro
Raritan Twp.
Readington Twp.
Stockton Boro
Tewksbury Twp.
Union Twp.
West Amwell Twp.

MERCER COUNTY
East Windsor Twp.
Hightstown Boro
Hopewell Twp.
Washington Twp.
West Windsor Twp.

MIDDLESEX COUNTY
Cranbury Twp.
East Brunswick Twp.
Helmetta Boro
Jamesburg Boro
Monroe Twp.
Old Bridge Twp.
Sayreville Boro
South Amboy, City of
South Brunswick Twp.
Spotswood Boro

MONMOUTH COUNTY
Aberdeen Twp.
Allenhurst Boro
Asbury Park, City of
Atlantic Highlands Boro
Avon-by-the Sea Boro
Belmar Boro
Bradley Beach Boro
Brielle Boro
Colts Neck Twp.
Deal Boro
Eatontown Boro
Englishtown Boro
Fair Haven Boro
Farmingdale Boro
Freehold Boro
Freehold Twp.
Hazlet Twp.
Highlands Boro
Holmdel Twp.
Howell Twp.
Interlaken Boro
Keansburg Boro
Keyport Boro

MONMOUTH COUNTY (Continued)
Lake Como Boro
Little Silver Boro
Loch Arbour, Village of
Long Branch, City of
Manalapan Twp.
Manasquan Boro
Marlboro Twp.
Matawan Boro
Middletown Twp.
Millstone Twp.
Monmouth Beach Boro
Neptune City Boro
Neptune Twp.
Oceanport Boro
Ocean Twp.
Red Bank Boro
Roosevelt Boro
Rumson Boro
Sea Bright Boro
Sea Girt Boro
Shrewsbury Boro
Shrewsbury Twp.
Spring Lake Boro
Spring Lake Heights Boro
Tinton Falls Boro
Union Beach Boro
Upper Freehold Twp.
Wall Twp.
West Long Branch Boro

MORRIS COUNTY
Boonton, Town of
Boonton Twp.
Butler Boro
Chatham Boro
Chatham Twp.
Chester Boro
Chester Twp.
Denville Twp.
Dover, Town of
East Hanover Twp.

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General Information

MORRIS COUNTY (Continued)
Florham Park Boro
Hanover Twp.
Harding Twp.
Jefferson Twp.
Kinnelon Boro
Lincoln Park Boro
Long Hill Twp.
Madison Boro
Mendham Boro
Mendham Twp.
Mine Hill Twp.
Montville Twp.
Morris Twp.
Morristown, Town of
Morris Plans Boro
Mountain Lakes Boro
Mt. Arlington Boro
Mt. Olive Twp.
Netcong Boro
Parsippany-Troy Hills Twp.
Pequannock Twp.
Randolph Twp.
Riverdale Boro
Rockaway Boro
Rockaway Twp
Roxbury Twp.
Victory Gardens Boro
Washington Twp.
Wharton Boro

OCEAN COUNTY
Barnegat Twp.
Bay Head Boro
Beachwood Boro
Berkeley Twp.
Brick Twp.
Dover Twp.
Island Heights Boro
Jackson Twp.
Lacey Twp.
Lakehurst Boro
Lakewood Twp.
Lavallette Boro
Manchester Twp.

OCEAN COUNTY (Continued)
Mantoloking Boro
Ocean Twp.
Ocean Gate Boro
Pine Beach Boro
Plumsted Twp.
Point Pleasant Boro
Point Pleasant Beach Boro
Seaside Heights Boro
Seaside Park Boro
South Toms River

PASSAIC COUNTY
Bloomingdale Boro
Pompton Lakes Boro
Ringwood Boro
Wanaque Boro
Wayne Twp.
West Milford Twp.

SOMERSET COUNTY
Bedminster Twp.
Bernards Twp.
Bernardsville Boro
Branchburg Twp.
Bridgewater Twp.
Far Hills Boro
Green Brook Twp.
Hillsborough Twp.
Peapack-Gladstone Boro
Warren Twp.
Watchung Boro

SUSSEX COUNTY
Andover Boro
Andover Twp.
Branchville Boro
Byram Twp.
Frankford Twp.
Franklin Boro
Fredon Twp.
Green Twp.
Hamburg Boro
Hampton Twp.
Hardyston Twp.

SUSSEX COUNTY (Continued)
Hopatcong Boro
Lafayette Twp.
Montague Twp.
Newton, Town of
Ogdensburg Boro
Sandyston Twp.
Sparta Twp.
Stanhope Boro
Stillwater Twp.
Sussex Boro
Vernon Twp.
Walpack Twp.
Wantage Twp.

UNION COUNTY
Berkeley Heights Twp.
Mountainside Boro
New Providence Boro
Springfield Twp.
Summit, City of

WARREN COUNTY
Allamuchy Twp.
Alpha Boro
Belvidere, Town of
Blairstown Twp.
Franklin Twp.
Frelinghuysen Twp.
Greenwich Twp.
Hackettstown, Town of
Hardwick Twp.
Harmony Twp.
Hope Twp.
Independence Twp.
Knowlton Twp.
Liberty Twp.
Lopatcong Twp.
Mansfield Twp.
Oxford Twp.
Phillipsburg, Town of
Pohatcong Twp.
Washington Boro
Washington Twp.
White Twp

JERSEY CENTRAL POWER & LIGHT COMPANY

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General Information

H – Customer Contact Information:

Emergency / Power Outage Reporting	1-888-544-4877
General Customer Service	1-800-662-3115
Payment Options	1-800-962-0383
Telecommunications Relay Service (TRS) for the Hearing Impaired	711

Morristown General Office
300 Madison Avenue, Morristown, NJ 07962-1911 1-973-401-8200

Customer Billing Questions or Complaints
JCP&L 76 S. Main Street, A-RPC, Akron, OH 44308-1890

Website:
http://www.firstenergycorp.com

Northern Region Business Offices:

Morristown	300 Madison Avenue, Morristown, NJ 07962	**ALL**
Hopatcong	175 Center Street, Landing, NJ 07850	**TELEPHONE**
Phillipsburg	400 Lincoln Street, Phillipsburg, NJ 08865	**INQUIRIES**
		PLEASE USE
Central Region Business Offices:		**CUSTOMER**
Allenhurst	300 Main Street, Allenhurst, NJ 07711	**CONTACT**
Toms River	25 Adafre Avenue, Toms River, NJ 08753	**INFORMATION**
Old Bridge	1345 Englishtown Road, Old Bridge, NJ 08857	**ABOVE**

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JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 14 ELECTRIC - PART II Original Sheet No. 1

PART II
STANDARD TERMS AND CONDITIONS
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STANDARD TERMS AND CONDITIONS – TABLE OF CONTENTS

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JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 14 ELECTRIC - PART II Original Sheet No. 5

Section 1 - Service Availability

NOTE: Unless specifically stated otherwise, Part II of the Company's Tariff (Standard Terms and Conditions) generally describes the responsibilities of and obligations between Customers and the Company. Specific standards governing the relationship between Customers and the Alternative Electric Supplier and between the Alternative Electric Supplier and the Company have been set forth by the BPU and are noted with references to such BPU Order(s) where applicable to the Company's Tariff.

1.01 Characteristics of Service: The standard electrical supply service provided by the Company is alternating current with a nominal frequency of 60 hertz. Not all types of service listed below are available at all locations, and service voltages other than secondary may be specified by the Company under special conditions such as may relate to the location, size, or type of load. The Company may specify the voltage, phase, and minimum and maximum load that it will supply at any particular voltage. The Company will furnish transformation facilities for secondary service up to a maximum of 300 KVA pole-mounted or 2500 KVA pad-mounted per contract location. Contract locations requiring in excess of these limits may, at the Company's discretion, be provided untransformed service, in which case the customer shall install, own, operate, and maintain the necessary transformation and associated facilities, except metering, in accordance with Company service requirements. Subject to the foregoing limitations, the types of service available with their nominal voltages are:

Secondary Service:

Single-phase	2 wire	120 volts
Single-phase	3 wire	120/240 volts
Single-phase	3 wire	120/208Y volts
Three-phase	4 wire	120/240 volts
Three-phase	4 wire	120/208Y volts
Three-phase	4 wire	277/480Y volts

Primary Service:

Single-phase	2 wire	2400 volts
Single-phase	2 wire	4800 volts
Three-phase	3 wire	2400 volts
Three-phase	4 wire	2400/4160Y volts
Three-phase	3 wire	4800 volts
Single-phase	2 wire	7200 volts
Three-phase	4 wire	7200/12470Y volts
Three-phase	4 wire	7620/13200Y volts
Three-phase	3 wire	13200 volts
Three-phase	4 wire	19900/34500Y volts

Transmission Service:

Three-phase	3 wire	34500 volts
Three-phase	3 wire	115000 volts
Three-phase	3 wire	230000 volts

The Company must always be consulted regarding the type of Service to be supplied.

Section 1 - Service Availability

1.02 Single Point of Delivery: The Company will designate the Point of Delivery and meter location. Service under a particular Service Classification will be supplied to each building or contract location through only one set of Service Connection conductors and metering equipment, except where the Service Classification may require otherwise or where, for economy, engineering, or operating considerations or by reason of applicable codes or governmental regulations, the installation of more than one Service Connection is necessary. Such duplicate or auxiliary delivery sources shall be furnished by separate contract under the applicable Service Classification and special provision. Service so delivered shall be used only at the premises where the Service is connected.

1.03 Compliance with Service Classification: Service provided by the Company shall not be used for purposes other than those recognized within the applicable Service Classification or pursuant to any special provisions under which the Customer is being served. When the use of Service is not in compliance with the terms of any such special provisions or Service Classification, the Customer shall be transferred to and billed under the applicable schedule of charges or disconnected from Service as provided for in this Tariff. (Also see 4.07 and 7.03)

1.04 Residential Purposes: Electric loads required for the operation and use of an individual residence. Such loads may include that for lighting, cooking, appliance operation and water pumping as well as space and water heating. Also see Part I, Section F, Definition (14) for definitions of residence and residential structures.

1.05 Resale of Service: Customers shall not resell Service for profit. Customers who distribute electric energy from their Point of Delivery to other occupants of the premises may install metering at their own expense to determine the energy usage and amount owed to the Customer for energy usage at those sub-locations. Where the use of the premises is basically residential, such meters of sub-locations will be permitted only for those buildings constructed prior to January 1, 1978, which are co-operative or condominium residential apartment buildings, or are publicly financed or government-owned. A reasonable administrative charge may be made by the customer to the other occupants for determining and billing them for their energy usage.

For multiple occupancy residential buildings constructed after January 1, 1978, separate metering owned and installed by the Company is required for each dwelling unit as provided in the New Jersey Uniform Construction Code.

1.06 Unusual Conditions: The Company, at its sole discretion, may discontinue or refuse to provide Service to loads which might adversely affect the normal operation of facilities of the Company or its customers. Service to such loads may be provided where the customer, at its own expense, has installed corrective equipment in accordance with general or individual non-discriminatory requirements and specifications of the Company. The Company may also discontinue or refuse to supply service to loads so installed or connected that an unbalance greater than 10% exists between the phases of the customer's service. Customers should contact the Company prior to purchasing or connecting motors or other equipment to determine the maximum allowable inrush current and/or to determine the suitability of the equipment to the Company's system. (Also see Section 4.05)

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 14 ELECTRIC - PART II Original Sheet No. 7

Section 1 - Service Availability

1.07 Curtailable Load Limitation: The curtailable load of all customers provided for under this Tariff shall not exceed 2.5% of the Company's annual peak load in the preceding calendar year.

1.08 Multiple Services for Transmission Customers: Service will be supplied to several delivery points at the same or different voltages as mutually agreed, providing that such delivery points are connected together by interconnecting lines and transformation facilities which are either owned, operated, and maintained by the Customer, or owned, operated, and maintained wholly or in part by the Company, upon payment to the Company of a monthly charge of 1.5% of the original cost of such facilities as are provided by the Company. Such interconnection by mutual agreement may be operated either normally closed or open, and in either case shall be changed only by or at the direction of the Company for emergency and maintenance purposes. Where such interconnection is available, each separate delivery point will be individually metered, and billing shall be based on the sum of the highest coincident demands and the sum of the kilowatt-hours registered at the individual metering points after correcting for transformation losses. Such meter registrations are not measured at transmission voltage.

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 14 ELECTRIC - PART II Original Sheet No. 8

Section 2 - Service Applications, Agreements & Contracts

2.01 Application and Connection: All Applicants seeking to receive any type of Service from the Company under this Tariff shall contact the Company and specifically request the type and nature of Service. An Applicant for any Service under this Tariff may be required to sign an application or contract for Service. However, the Company may, in its sole discretion, accept an oral application from an Applicant. Applicants for Service shall supply to the Company all information deemed necessary by the Company from time to time to provide such Service including, but not limited to, connected electrical load, types of electrical equipment, and the mode of operation of the electrical equipment.

Upon the receipt of Service, the Applicant shall become a Customer of the Company. At any time, the Customer shall inform the Company in advance of any proposed additions to (or decreases in) the Customer's Connected Load.

Whenever Service is initiated to any Customer in any particular location or resumed after discontinuance at the request of the Customer, a Service Charge shall be made as specified in Part III of the Tariff.

If a Delivery Service Customer, for whatever reason, receives electric supply from the Company, that Customer will be considered a Full Service Customer beginning with the date on which such electric supply is furnished to the Customer by the Company.

2.02 Forms and Information: The Company will, upon request, explain the provisions of its Tariff and the conditions under which Service can be obtained. It is the responsibility of any Applicant for new or modified Service to obtain from the Company information regarding the characteristics of available Service, the Point of Delivery of Service, its designation of the point of Service Connection and meter location, and such other information as may be necessary to assure that the Customer's installation will be compatible with the facilities and Service the Company will provide before making the initial electrical installation or planning material changes in an existing installation. The Company will furnish such application and contract forms as may be appropriate. The Applicant shall supply all of the information called for by such forms.

2.03 Selection of Service Classification: The Company will assist in the selection of the Customer’s applicable Service Classification. In furnishing such assistance, the Company assumes no responsibility whatsoever. If for any reason the Customer fails to make a selection, the Company will assign a Service Classification based upon facts at hand at the time Service is furnished. A Customer may, upon written notice to the Company, elect to change and to receive Service under any other applicable Service Classification or special provision. The Company will bill the Customer under the Service Classification so selected for Service delivered from the date of the next scheduled meter reading, but the Company may refuse to permit any further change in selection of Service Classification or special provision during the next twelve months, except as may be permissible under Section 1.03.

Section 2 - Service Applications, Agreements & Contracts

2.04 Modification or Rejection of Application: The Company may place limitations on the amount and character of Service it will provide, or may refuse to provide Service to new Customers or to any additional load of existing Customers, if it is not able to obtain, install, operate, or maintain the necessary equipment and facilities to provide such Service. The Company, after proper notice, may refuse to initiate Service or may discontinue Service to an Applicant, or to a Customer who is a member of the household or is a business associate, or landlord, of a former Customer then indebted to the Company for Services provided by the Company at any location, if the Company has reason to believe that substantially the same household or business will or does occupy the premises to be or being served and that the purpose of the present or earlier application is or was to circumvent payment of such indebtedness. However, if the household or business is not the same, the Company can only transfer the outstanding balance of amounts owed to the Company for Services provided by the Company to the former Customer of record for Service rendered at the prior location.

2.05 Contract by Use of Service: Receipt and use of Service provided by the Company shall render the recipient a Customer of the Company. If such Service is provided and accepted, or used in the absence of a written agreement for Service approved by the Company, such recipient shall be deemed to have entered into an agreement with the Company, the furnishing, receipt, and use of such Service shall be subject to the provisions of this Tariff and such Customer shall be charged for such Service in accordance with the applicable Service Classification.

2.06 Term of Contract: The term of contract is stated in the applicable Service Classification or in a written agreement. Customers shall give notice of intention to terminate Service to a responsible agent of the Company in accordance with the requirements of any applicable Service Classification or written agreement and, in any event, reasonably in advance of intended Service termination or change in Customer identity. Termination of Service on notice from the Customer, or for any other reason permitted by this Tariff prior to the completion of a contract for Service, shall not relieve the Customer from payment of the charges for the unexpired portion of the term and the same shall be due and payable immediately.

2.07 Unauthorized Use: Unauthorized connection to the Company's facilities, or the use of Service (either metered or unmetered) without Company authorization may be terminated by the Company without notice. The use of Service without notice to the Company shall render the End User or Beneficiary liable for any amount due for Service provided to the premises since the last reading of the meter as shown by the Company's records or for unmetered Service used since the last billing.

2.08 Statements by Agents: No representative of the Company has authority to modify any provision contained in this Tariff or bind the Company by any promise or representation contrary thereto, and the Company shall not be bound thereby.

2.09 Special Agreements: As a condition for establishing, continuing, or resuming the provision of Service in a situation where the Company incurs or will incur greater than normal investment cost or operating expense in order to meet the Customer's special or unusual Service requirements or to protect the Company's system from undue disturbance of voltage regulation or other adverse effects and in order to avoid undue discrimination, the Company may require an agreement for a longer term than specified in the applicable Service Classification, may require a contribution in aid of construction, and may establish such minimum charges and facilities charges as may be equitable under the circumstances. (Also see Section 4.05)

Section 3 - Billings, Payments, Credit Deposits & Metering

3.01 Measurement of Electricity Consumption: The Service provided to the Customer will be measured separately for each Point of Delivery by metering. Bills will be based upon the registration of such metering equipment except as may be otherwise provided in this Tariff. Such registration shall be conclusive as measuring the quantity of Service received by the Customer except when (i) the metering equipment fails to register or is determined to be registering outside the limits of accuracy prescribed by the BPU, or (ii) the electric service registered on such meter was delivered outside the tenant-Customer's premises without the tenant-Customer's permission (N.J.A.C. 14:4-7.8).. In some instances the Company may, at its sole discretion, allow for unmetered Service. (Also see Sections 3.15 and 3.16)

3.02 Separate Billing for Each Installation: Service provided through each meter shall be billed separately in accordance with this Tariff. Conjunctive billing, which is the combination of the quantities of energy, demand, or other billing elements of two or more meters or Services into respective single quantities for the purpose of billing as if the bill were for a single meter or Service, will not be permitted except where more than one meter has been installed for Company operating reasons. (Also see Sections 1.02 and 3.15)

3.03 Meter Reading and Billing Period: Unless otherwise specified, the charges for Service are stated on a monthly basis. Meters are read on a regular schedule, as nearly as practicable every 30 days. The term "month" as used in this Tariff, generally means the period between any two consecutive regularly scheduled meter readings. The term "billing period" usually refers to the interval of time elapsing between two consecutive meter readings, but it may mean other time intervals, either actual or estimated, taken or made for the purpose of computing the amount due to the Company from the Customer. Bills to Customers will normally be rendered monthly, but the Company may, in its sole discretion, read meters and render bills generally, or to limited groups of Customers, on other than a monthly basis for either experimental purposes or as a regular procedure, after giving reasonable notice to the affected Customers and to the BPU. In such event the monthly charges stated in the applicable service classification shall be prorated to conform to the new billing period. (See NJAC 14:3-7.4)

3.04 Prorating of Monthly Charges: All bills for periods other than 26 to 35 days inclusive will be computed by prorating the monthly charges provided in the applicable service classifications on the basis of the relationship between the number of days in the billing period and 30 days.

3.05 Estimated Bills: Where the Company has not obtained a reading of the meter it may submit a bill for the minimum charge, or estimate the amount of Service provided and submit an estimated bill. Such bill is subject to adjustment on the basis of the actual Service provided as established by the next actual meter reading, or for any unusual circumstances known to have affected the amount of Service provided.

The Company reserves the right to discontinue Service when a meter reading has not been obtained for eight months or more and after written notice is sent to the customer per NJAC 14:3-7.2. The Company will use all reasonable means to obtain a meter reading before discontinuing Service. (Also see Section 7.03 and NJAC 14:3-3A.1)

Section 3 - Billings, Payments, Credit Deposits & Metering

3.06 Billing Adjustments: An adjustment of charges due to the Company for Services provided by the Company will be made if a meter is found to be registering as fast; more than two percent. The adjustment will be made corresponding to the percentage error as found in the meter covering the entire period which the meter registered inaccurately, provided such a period can be determined. If such period cannot be determined, a correction shall be applied to ½ of the total amount of billing affected since the most recent prior meter test. No adjustment shall be made for a period greater than the time during which the customer has received service through the meter in question. Billing adjustments will be in accordance with N.J.A.C. 14:3-4.6 and shall not be for a period of more than six years prior to the time the reason for the adjustment became known to the Company.

3.07 Billing of Charges in Tariff: Unless otherwise designated, the charges set forth in this Tariff shall apply to Service rendered on and after the effective date specified in the applicable Service Classification.

3.08 Payment of Bills: Bills for Service provided by the Company are payable when rendered and are due within fifteen days of the mailing date of the bill or as otherwise prescribed by regulation NJAC 14:3-3A.3. They can be paid at any business office of the Company, to any duly authorized collector or collection agency, by mail, or by electronic funds transfer. If a bill is not paid by the date indicated on the bill, the Company, on not less than ten days written notice, may discontinue service to the Customer after 27 days following rendition of the bill or as otherwise prescribed by regulation. (See NJAC 14:3-3A.3)

Whenever a residential Customer advises the Company that the Customer wishes to discuss a deferred payment agreement because of a present inability to pay a total outstanding bill and/or a security deposit, the Company will make a good faith effort to provide the Customer with a reasonable deferred payment agreement. Either prior to or after the discontinuance of service for non-payment, a residential Customer may be required to pay a down payment of not more than 25% of the total outstanding bill due at the time of the agreement. Deferred payment agreements which extend more than two months must be in writing. The Company is not required to offer or enter into more than one deferred payment agreement in a 12-month period, but the Company may, in its sole discretion, elect to offer more than one such agreement in the same 12-month period. If the Customer defaults on any of the terms of the agreements, the Company may discontinue service after providing the Customer with a notice of discontinuance. (See NJAC 14:3-7.7)

A Customer's failure to receive a bill shall not relieve the Customer of any of the Customer's obligations hereunder.

Where a non-residential Customer requests a deferred payment agreement, the agreement shall be limited to a period of no more than three months, and the Customer may be required to make a partial payment at the time of entering into the deferred payment agreement. The amount of the partial payment shall be no more than one half of the amount past due and owing at that time. The existence of a deferred payment agreement does not relieve the Customer of applicable monthly late payment charges. (See Section 3.19)

3.09 Guarantee of Payment: Where the credit of an Applicant for Service is impaired or not established, or where the credit of a Customer has become impaired, a money deposit or other guarantee satisfactory to the Company may be required as security for the payment of bills for Service before the Company will commence or continue Service. If a residential Customer's Service has been terminated for non-payment of bills, the Company may not condition restoration of Service on payment of a deposit unless said deposit had been included as a charge on prior bills, or prior notice to the Customer had been given. (See NJAC 14:3-3.4)

Section 3 - Billings, Payments, Credit Deposits & Metering

3.10 Amount of Credit Deposit: The deposit from the Customer shall be not less than twice the estimated or actual bill for a single billing period at the applicable rate. In the case of a Customer taking Service for less than 30 days, a credit deposit may be required in an amount equal to the estimated bill for such temporary period. The Company will issue a receipt to each Customer making a deposit. (See NJAC 14:3-3.4)

3.11 Interest on Credit Deposit: All money deposits under Section 3.09 shall bear simple interest payable at the rate and in the manner specified under NJAC 14:3-3.5(d). Deposits shall cease to bear interest upon termination of Service.

3.12 Return of Credit Deposit: Upon termination of Service and payment in full of all unpaid bills for Service, the Company will return the deposit plus accrued interest, or will deduct from the deposit and interest all amounts due and return the difference, if any, to the depositor. The Company shall have a reasonable time in which to read meters and to ascertain that the obligations of the Customer have been fully performed before being required to return any deposit. The credit deposit is not a floating credit available to be used by the Customer for the payment of interim bills for service, but the Company may apply the deposit and any accrued interest against any unpaid bills and require the Customer, as a condition on continuing Service, to restore the deposit to an amount, determined in accordance with the principles set forth in Sections 3.09 and 3.10, sufficient to secure the payment of future bills. Residential customer accounts will be reviewed at least once every year and non-residential Customer accounts at least once every two years. Should such review indicate that the Customer has established satisfactory credit with the Company, the credit deposit plus accrued interest, if any, will be returned to the depositor. Such return of a credit deposit shall not serve to waive the Company's right to re-establish the credit deposit as required herein above. The Company may require surrender of the receipt issued when the deposit was made, or in lieu thereof, proof of identity before returning the deposit or any part thereof. (See NJAC 14:3-3.5)

3.13 Final Bill: A customer intending to discontinue Service shall give the Company reasonable notice thereof and arrange for the reading of the meter. Where the Customer is discontinuing all Service, the reading shall be regarded as a final reading and the Company will read the meter within forty-eight hours of receipt of such notice unless a holiday or a weekend intervenes or the Customer desires otherwise. If, because of conditions occasioned by the Customer, or by reason of compliance with the Customer's request, the final reading of the meter must be obtained outside of regular business hours, the Customer will be subject to the service charges specified in the applicable Service Classification within this Tariff.

Whether or not the Customer gives notice of discontinuance, the Customer shall be liable for Service delivered to the premises until the final reading of the meter can be obtained by the Company. Where the Customer is discontinuing all Service, the bill for Service rendered until the final meter reading, plus all other charges due and any applicable minimum charge for the unexpired term of a contract, is due and payable immediately upon presentation. Where the Service in question is unmetered, a final bill shall be rendered upon discontinuance of Service.

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Section 3 - Billings, Payments, Credit Deposits & Metering

3.14 Taxes on Contributions in Aid of Construction and Customer Advances or Deposits: Any contribution in aid of construction ("CIAC"), customer advance or deposit, or other like amount received from Customers which shall constitute taxable income as defined by the Internal Revenue Service may be increased to include a payment equal to the applicable current taxes incurred by the Company as a result of receiving such monies, less the net present value of future tax benefits related to the tax depreciation guideline-life applicable to the property constructed with such monies, which for transmission or distribution items shall be taken to be 20 years. The discount rate to be used for such present value calculation will be the Company's last allowed overall rate of return.

3.15 Unmetered Service: Where the Customer's equipment is of such a character and its operation is so conducted that the Customer's use of service at the Point of Delivery is substantially invariable over the period Service is supplied, thus permitting accurate determination of billing quantities by calculation based on the electrical characteristics of such equipment, the Company may omit the installation of metering equipment and, with the consent of the Customer, use the respective quantities, so determined, for billing purposes under the applicable Service Classification. The Customer shall not make any change whatever in the equipment or mode of operation thereof, Service to which is billed in the foregoing manner, without first obtaining the Company's consent in writing. If the Customer changes equipment or mode of operation, any Service to such changed equipment or operation shall be deemed unauthorized use and shall be subject to discontinuance as provided elsewhere in this Tariff.

3.16 Non-measurable Loads: Customers with equipment which creates unusual fluctuations, which cannot be measured by standard metering facilities, shall have the maximum 15-minute demand, monthly KWH, and reactive component calculated for such equipment, and added to any such measured quantities for the customer's remaining load for billing purposes under the applicable Service Classification.

3.17 Equal Payment Plan for Individual Residential Dwelling Units: The Company may, upon request by a residential Full Service Customer, determine a payment plan of twelve equal monthly payments for the Customer. Monthly payments required under this plan may be revised by the Company one time during the payment plan period as rate changes or special conditions warrant. If actual charges are more or less than the estimated amounts, billing adjustments necessary to provide for the payment of the actual charges due for Service rendered under this plan shall be made in the twelfth month of the plan, or in the event the Equal Payment Plan is terminated, on the next bill. The Company may terminate this plan at any time as to any Customer if any monthly bill rendered to such Customer under this plan is unpaid when the next monthly bill is rendered. (See NJAC 14:3-7.5)

3.18 Returned Payment Charge: A charge of $15 will be assessed against a Customer's account when a check or an electronic payment or other form of funds transfer, which has been issued to the Company, is returned by the bank as uncollectible, or otherwise dishonored by the bank from which the funds were drawn.

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Section 3 - Billings, Payments, Credit Deposits & Metering

3.19 Monthly Late Payment Charge: Upon the non-receipt of payment for services provided by the Company or an Alternative Electric Supplier by a Customer receiving Service under Service Classifications GS, GST, GP, GT, SVL, MVL, ISL, LED and Rider CEP and receiving a bill for such service rendered by the Company, as opposed to a consolidated bill rendered by an Alternative Electric Supplier, except for government entities, a Late Payment Charge at the rate of 1.5% per monthly billing period shall be applied. This charge will be applied to all amounts previously billed, including any unpaid late payment charge amounts applied to previous bills, which are not received by the Company when the next regular bill is calculated. The amount of the Late Payment Charge to be added to the unpaid balance shall be determined by multiplying the unpaid balance by the monthly Late Payment Charge rate of 1.5%. (See NJAC 14:3-7.1)

3.20 Delinquent Charge: For Customers receiving Service under Service Classifications RS, RT, RGT, GS and GST, a field collection charge will be applied for each collection visit made by the Company to the Customer's premises, except Customers who qualify for protection under the standards set forth in the NJAC 14:3-3A.5 as detailed in the Stipulation of Final Settlement (Docket No. ER95120633).

3.21 Summary Billing: Upon a Customer's request and the Company's approval, a Customer with multiple Full Service accounts may receive Summary Billing, in which the billing information for the multiple accounts is reported on a single statement, for the convenience of the Customer. Summary Billing shall not be permitted for any delinquent accounts, and shall be permitted only in those cases where meter reading dates and due dates of the multiple accounts allow for Summary Billing without adversely affecting the timely payment of bills and where summary billing does not have an adverse financial impact on the Company. The Company may, in its sole discretion, discontinue Summary Billing, or charge Customers an additional amount for Summary Billing to offset any actual or potential adverse financial impact on the Company. A single due date for accounts that are billed in summary shall be established by the Company and provided to the Customer. Summary Billing shall not commence unless and until the Customer agrees to the due date established for such Summary Billing.

3.22 Special Billing: The Company shall consider all requests from Customers to deviate from the Company's standard billing practices and procedures, including those described in this Tariff. The Company may, in its sole discretion, agree to provide special billing to a Customer, subject to, a payment by the Customer of all costs associated with the Company providing such special billing.

3.23 Metering: The Company shall maintain, install and operate meters and related equipment as necessary to measure and record the Customer's consumption and usage of all services provided under this Tariff. The Company may, in its sole discretion, install such meters and related equipment (including, but not limited to, telemetering equipment) it deems reasonable and appropriate to provide service to Customers under this Tariff. The Company may, in its sole and exclusive discretion, install such special metering as may be requested by a Customer, subject to the Customer paying all of the Company's material, labor, overheads and administrative and general expenses relating to such facilities.

The Company shall conduct inspections and tests of its meters in accordance with prudent electric practices and as otherwise prescribed by the BPU.

Section 3 - Billings, Payments, Credit Deposits & Metering

3.23 Metering: (Continued)

If requested by the Customer, the Company may, in its sole discretion, elect to provide kilowatt-hour pulses and/or time pulses from the Company's metering equipment. All costs for providing the meter pulses shall be paid by the Customer. If a Customer's consumption of kilowatts and/or kilowatt-hours increases as a result of interruptions or deficiencies in the supply of pulses for any reason, the Company shall not be responsible or liable, for damages or otherwise, for resulting increases in the Customer's bill.

If requested by a Customer, the Company may, in its sole discretion, elect to provide metering to a service location other than what is presently installed or otherwise proposed to be installed by the Company at that location. All costs for special metering facilities provided by the Company, including, but not limited to, all material, labor, overheads and administrative and general expenses, shall be billed to and paid by the Customer.

3.24 Advanced Metering Opt-Out

Any Full Service Customer or Delivery Service Customer who declines to have an AMI meter installed when notified, requests the transmitter of an AMI meter be disabled or requests an AMI meter be removed for a digital non-AMI meter, will be classified as having opted-out of AMI metering and shall be subject to the following terms:

1.) Monthly Meter Reading – A monthly fee of $15.00 shall apply to any customer who: refuses to allow the Company to install an AMI meter; requests that the transmitter of an AMI meter be disabled; or requests that an AMI meter be removed.

2.) Meter Replacements – Customers shall be charged a one-time fee of $44.46 for the replacement of an AMI meter with a non-AMI meter. The replacement meter will be manually read. This fee will also apply to any customer who elects to participate in AMI metering after requesting the removal of such meter.

3.) Access to Premises – Customers who Opt-out of AMI metering must provide reasonable access for meter reading and meter maintenance that free of safety hazard to customers, the public or the utility personnel or facilities If the customer fails to provide access for two months in a twelve-month period, then the customer will be required to: (a) relocate their metering equipment to an external location, at the customer’s expense; or (b) permit the Company to reinstall an AMI meter or enable the AMI meter transmitter feature.

Customers who are taking service under a time differentiated rate, billed with time dependent rates or are involved in net metered generation will not have the option to opt out of having a smart meter.

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Section 4 - Supply and Use of Service

4.01 Continuity of Service: The Company will use reasonable diligence to maintain a regular and uninterrupted provision of Service, but should the Service be interrupted, curtailed, suspended, or discontinued by the Company for any of the reasons set forth in Section 7 of these Standard Terms and Conditions, or should the Service be interrupted, curtailed, deficient, defective, or fail by reason of any natural disaster, accident, act of a third party, strike, legal process, governmental interference or by reason of compliance in good faith with any governmental order or directive, notwithstanding that such order or directive subsequently may be held to be invalid, or other causes whatsoever beyond its control, the Company shall not be liable for any loss or damage, direct or consequential, resulting from any such suspension, discontinuance, interruption, curtailment, deficiency, defect, or failure. The Company will not be responsible for any damage or injury arising from the presence or the use of Service provided to the Customer by the Company after it passes from the Company's facilities to the Point of Delivery, unless such damage or injury is caused by the sole negligence or willful misconduct of the Company. Any damage or injury arising from occurrences or circumstances beyond the Company's reasonable control, or from its conformance with standard electric industry system design or operation practices, shall be conclusively deemed not to result from the negligence of the Company. Due to the sensitive nature of computers and other electric and electronically controlled equipment, Customers, especially three-phase Customers, are advised to and should provide protection against such variations in power and voltage supply.

4.02 Temporary Service: Service for a temporary or short term period will be provided and billed under the applicable Service Classification when the Company's available installed facilities are of adequate capacity to render such Service, provided the Customer pays in advance the estimated net cost of installing and removing all facilities provided to furnish such Service. If the total period of temporary Service is less than one month, the total billing for such period shall not be less than the stated monthly minimum of the applicable Service Classification. At the option of the Company, bills for temporary Service may be prorated and rendered at periodic intervals of less than one month and are due and payable upon presentation. The Company's specifications for the Customer's installation are available from the Company upon request.

4.03 Transformation Facilities for Transmission Customers: Where, for the mutual convenience of the Company and Customer, the transformation equipment at a delivery point is utilized by both parties, the Company will provide such facility at a monthly charge of 1.5% of the prorated cost. The prorated cost shall be (1) the product of (a) the highest 15-minute demand (rounded to the next highest 100 KW) established by the Customer on such commonly-used transformation facility since Service was originally established, and (b) the Company's book cost of such commonly-used transformer substation less those items of equipment devoted solely to uses other than supplying the Customer, (2) divided by the maximum capability of the transformation equipment when operating under load conditions. In the event that the transformer bank's maximum capability is altered, either by changes in the transformers, the transformer cooling equipment, or in the characteristics of the Customer's load, item (2) above shall be redetermined to reflect the changed conditions.

Section 4 - Supply and Use of Service

4.04 Emergency Curtailment of Service: The Company may curtail or discontinue the provision of Service to any Customer, upon reasonable notice if possible, in the event it becomes necessary to do so in case of emergencies or in compliance with an order or directive of Federal, State, or municipal authorities. The Company may interrupt Service to any Customer or Customers in an emergency threatening the integrity of its system or to aid in the restoration of Service if, in its sole judgment, such action will alleviate the emergency condition and enable it to continue or restore Service consistent with the public welfare. (Also see Sections 4.01 and 7.02) In the event of an actual or threatened restriction of fuel supplies available to its system or the systems to which it is directly or indirectly connected, the Company may curtail or interrupt Service or reduce voltage to any Customer or Customers if, in its sole judgment, such action will prevent or alleviate the emergency condition. (See NJAC 14:3-3A.1)

4.05 Special Company Facilities: At the Customer's request, or as required, subject to approval by the Company, the Company will furnish and install on its system, special, substitute, or additional facilities to meet the Customer's special or additional requirements or to protect the Company's system from disturbance of standard voltage regulation that otherwise would be caused by the operation of customer's equipment. When the Company furnishes facilities not normally supplied or when the estimated or actual cost of such special substitute or additional facilities exceeds the estimated cost of the standard facilities that normally would be supplied by the Company without special charge, either (a) the Customer shall pay in a manner to be agreed upon a facilities charge annually amounting to 18% of such additional cost, or (b) by mutual agreement the Customer may pay an amount equivalent to such additional cost, plus applicable taxes. However, alternative (a) shall not be available unless the facilities are such as are commonly and usually transferred from place to place for use in the Company's system or are reasonably capable of reuse. The Customer may also be subject to other monthly or special charges in order to meet their special needs.

4.06 Single Source of Energy Supply: No Customer may maintain or operate any source of electric energy on his premises or at his contract location in a manner whereby such source may become interconnected with the Company's facilities without the prior written approval of the Company. Such prior approval may be conditioned, among other things, on the installation and operation by the Customer at the Customer's cost and expense of such switches and/or protective devices as the Company may deem necessary to prevent injury to persons or damage to property of either the customer or the Company. Such approved interconnection may be maintained only at the appropriate rates and charges as provided in this Tariff.

4.07 Changes in Customer's Installation: The Customer, prior to making any material increase or decrease in Connected Load, demand, or other conditions of use of Service or change of purpose, arrangement, or characteristics of electrical equipment, shall notify the Company of such intention so that the Company may determine if any changes in its distribution facilities or in the Point of Delivery will be required in order that safe, adequate, and proper Service may be supplied to the Customer under the proposed changed conditions. Prior to starting any work, the Customer or his agent shall submit for the Company's approval sufficient copies as required of the plans of such proposed installations, together with a list of the principal apparatus to be used. The Company will advise the Customer if any feature of the proposed changed conditions would be incompatible with such Service. (Also see Section 5.06) Such proposed changes in the Customer's Service conditions shall not be made effective until they have been approved by the Company.

Section 4 - Supply and Use of Service

4.08 Customer's Liability to Company: Failure of the Customer to give prior notice of changes in conditions as described in Section 4.07 shall render the Customer responsible and liable for any personal injury and any property damage caused by the changed conditions, including damage to the Company's property and injury to its employees. In those cases where the Customer's bill is based on the connected load, failure to give notice of changes therein will not relieve the Customer from liability for payment of proper charges for Service based upon such changed conditions from the date such change first occurred, nor entitle the Customer to a refund or adjustment if the charges billed exceed the amount that would normally be applicable under the changed conditions.

4.09 Request for Relocation of, or Work on, Company Facilities: When the Company is requested to relocate or work on its facilities and such relocation or work is for the purpose of enabling the Customer to work on or maintain his electrical facilities or building, or perform work or construction safely in the vicinity of Company equipment, the Customer shall pay to the Company, in advance of any relocation or work by the Company, the estimated cost to be incurred by the Company in performing such relocation or work. For work of a routine nature frequently performed within the Company's service area, the Company may specify a flat fee based upon the average costs of performing such work. (Also see Sections 6.04, 6.06, and 6.08)

4.10 Liability for Supply or Use of Electric Service: The Company will not be responsible for the use, care, condition, quality or handling of the Service delivered to the Customer after same passes beyond the point at which the Company's service facilities connect to the Customer's wires and facilities. The Customer shall hold the Company harmless from any claims, suits or liability arising, accruing, or resulting from the supply to, or use of Service by, the Customer.

4.11 Relocation of Meters or Service Equipment: Where meter locations are changed from indoor to outdoor, the Company may permit feeding back from the new meter location to the original Service Entrance. When an existing Service Entrance is to be changed, the old Service shall remain active and properly metered until the old Service is disconnected and the new Service is reconnected. When it is impractical to comply with this requirement, the Company must be contacted and arrangements made to accomplish the changeover. Metered and unmetered conductors will not be permitted in the same conduit or raceway, except in special cases where Company approval has been obtained.

4.12 Liability for Acts of Alternative Electric Suppliers: The Company shall have no liability or responsibility whatsoever to the Customer for any agreement, act or omission of, or in any way related to, the Customer's Alternative Electric Supplier.

Section 5 - Customer's Installation

5.01 General Requirements: The Customer's installation must conform to the Company's specifications and all requirements of municipal and State authorities and regulations set forth in the National Electric Code in effect at the time of such installation. The Company will, however, install and maintain facilities on the Customer's premises at the Customer's cost when the Company determines such installation and maintenance to be necessary or more convenient for the delivery of Service and there is mutual agreement as to the installation and maintenance cost. Where for engineering or operating reasons it is necessary or desirable to install a substation, transformers, capacitors, control, protective or other equipment on the Customer's premises in order to supply the Service required by the Customer, the Customer shall provide a suitable place and housing for such facilities. The Company's specifications for the Customer's installation are available from the Company upon request.

5.02 Service Entrance: The Customer's Service Entrance facilities shall extend from the Point of Delivery specified by the Company to an approved entrance switch cabinet located on the Customer's premises. With the exception of metering equipment and related facilities furnished by the Company, all of the facilities necessary to conduct electricity from the Point of Delivery to the Customer's circuits shall be installed, owned, and maintained by the Customer. The Customer must provide and install an approved service head and assure all fittings used in the Service Entrance provide a water-tight connection. At least three feet of wire must be left for the connection to the Service Drop on all services. (Specifications for service installations will be furnished by the Company upon request.)

5.03 Inspection and Acceptance: The Company may refuse to connect with any Customer's installation or to make additions or alterations to the Company's Service Connection when such installation is not in accordance with the National Electrical Code, or with the Company's requirements, or where a certificate approving such installations has not been issued by an electrical inspection authority certified by the New Jersey Department of Community Affairs for the area in which the installation is located, or by a City or County Inspection Authority having exclusive authority to make electrical inspection in such area. (See NJAC 14:3-8.3(g) and (h))

5.04 Special Customer Facilities: The Customer shall furnish at his own expense any special facilities necessary to meet his particular requirements for Service at other than the standard conditions specified under the provisions of the applicable Service Classification. (Also see Section 5.05)

5.05 Regulation of Power Factor: The Company shall have the right to require the Customer to maintain a power factor in the range of 87% to 100% coincident with the Customer's maximum on-peak monthly demand and to provide, at its sole expense, any corrective equipment necessary in order to do so. The Company may inspect the Customer's installed equipment and/or place instruments on the premises of the Customer in order to determine compliance with this requirement, as deemed appropriate by the Company. The installation by the Company of corrective devices necessary for compliance with this provision, shall, as deemed appropriate by the Company, be billed to the Customer under the provisions of Section 4.05. The Company is under no obligation to serve, or to continue to serve, a Customer who does not maintain a power factor acceptable to the Company. (Also see Sections 5.01 and 5.04)

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Section 5 - Customer's Installation

5.06 Change in Point of Delivery: In the event that the Company shall be required by any governmental authority to relocate its distribution facilities or to place any portion of them underground, the Customer shall at its own expense make such changes in its Service Entrance and/or in its underground Service Connection as may be necessary in order to conform to the new Point of Delivery specified by the Company. Any change requested by the Customer in the location of the existing Point of Delivery, if approved by the Company, will be at the expense of the Customer.

5.07 Liability for Customer's Installation: The Company will not be liable for damages to or injuries sustained by the Customer or others, or by the equipment or property of Customer or others, by reason of the condition, character, or operation of the Customer's wiring or equipment, or the wiring or equipment of others.

5.08 Meter Sockets and Current Transformer Cabinets: Upon the Company's designation of a Point of Delivery at which its Service line will terminate, the Customer shall provide, at its sole cost and expense, a place suitable to the Company for the installation of metering and all other electric facilities needed for the provision of electric energy by the Company or an Alternative Electric Supplier. It shall be the Customer's responsibility to furnish, install, and maintain self-contained meter sockets and current transformer cabinets in accordance with Company specifications which are available upon request.

5.09 Restricted Off-Peak Water Heater Specifications: Service supplied under Service Classification RS - Residential Service, Special Provision (a), or Service Classification GS - General Service Secondary, Special Provision (d), must conform to the following requirements as well as any other applicable conditions of Service:

(a) The minimum capacity of the water heater should not be less than 50 gallons.
(b) Should the water heater have two non-inductive heating elements, each shall be controlled by its own thermostat and both shall be electrically interlocked to prevent simultaneous operation, with the upper heating element located to heat the top one-quarter of the tank volume and the lower element located to heat the entire tank.
(c) The upper heating element may be wired to operate during the on-peak as well as off-peak periods, whereas the lower element, or single element (in a one-element water heater), may operate only during the off-peak periods.
(d) The wattage of each heating element shall not be in excess of 30 watts per gallon of tank volume, rounded to the nearest 500 watts.
(e) Service to water heaters will be supplied at single-phase 208 or 240 volts, depending on the voltage available. For the supply of equipment with one tank or a combination of tanks in excess of 250 gallons or in excess of 7500 watts, the Company must be consulted for installation specifications.

Section 5 - Customer's Installation

5.10 Restricted Controlled Water Heating Specifications: Service supplied under Service Classification RS - Residential Service, Special Provision (b), or under Service Classification GS - General Service Secondary, Special Provision (e), must conform to the following requirements as well as any other applicable conditions of Service:

(a) The water heater shall have two non-inductive heating elements, each controlled by its own thermostat and electrically interlocked to prevent simultaneous operation.
(b) The upper heating element shall be located to heat the top one-quarter of the tank volume and the lower element located to heat the entire tank.
(c) The wattage of each element shall not be in excess of 35 watts per gallon of tank volume rounded to the nearest 500 watts for water heater of 40 gallons or more.
(d) Thirty-gallon water heaters may contain either one or two heating elements, with an element size not to exceed 1500 watts.

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Section 6 - Company's Equipment on Customer's Premises

6.01 Ownership, Maintenance and Removal: The Company shall furnish, install and maintain the meters, related equipment and facilities necessary for Service unless otherwise stated. All facilities and equipment supplied by the Company shall remain exclusively its property. The Company may remove such facilities and equipment from the premises of the Customer after termination of Service.

6.02 Customer's Responsibility: Under certain circumstances, it may be necessary for the Company to install equipment on the Customer's premises. This equipment may be placed in vaults, manholes, hand-holes, outdoor substations on concrete pads, etc. These Customer-owned facilities must be constructed in accordance with all applicable codes and to the Company's specifications. Prior to starting work, the Customer or his agent shall submit for the Company's approval plans of such proposed installations, together with a list of the principal apparatus to be used. The Customer shall be responsible for the protection and safe-keeping of the facilities and equipment of the Company while on the Customer's premises and shall not permit access thereto except by duly authorized governmental officials and representatives of the Company. The Customer should notify the Company immediately if any question arises as to the authority or credentials of any person claiming to be a governmental official or a Company representative. Any malfunction or defect in the Company's equipment observed by the Customer should be reported to the Company immediately. (See Section 6.04)

6.03 Access to Customer's Premises: The Company shall have the right to construct, operate, modify, replace and/or maintain any and all facilities it deems necessary to render Service to the Customer and adjoining customers upon, over, across and/or under lands owned or controlled by the Customer. The Company shall have the right of reasonable access to all property furnished by the Company, at all reasonable times for the purpose of inspection of any premises incident to the rendering of service, reading meters, or inspecting, testing, or repairing its facilities used in connection with providing the Service, or for the removal of its property. The Company shall have the right to enter upon the lands owned or occupied by the Customer for the purpose of moving, removing, replacing, altering, accessing, servicing or maintaining any structures, fixtures, equipment, instruments, meters or other property owned by the Company, above or beneath such lands, and shall have the right to trim, cut, move, clear or destroy any trees, shrubs, plants or other growth on such lands as necessary to keep or prevent same from endangering or interfering with the Company's structures, fixtures, equipment, instruments, meters or other property, or with the providing of safe, adequate and reliable Service. The Customer shall obtain, or cause to be obtained, all permits needed by the Company for access to the Company's facilities. Access to the Company's facilities shall not be given except to authorized employees of the Company or duly authorized governmental officials. During an alleged diversion of Service, it is the Company's responsibility to obtain access to the Company’s equipment in accordance with NJAC 14:3-3.6 and 6.8. (See Section 7.03)

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Section 6 - Company's Equipment on Customer's Premises

6.04 Tampering: In the event it is established that the Company's wires, meters, meter seals, switch boxes, or other equipment (including, but not limited to, revenue protection locks, meters and other devices) on the Customer's premises have been tampered with, the Customer shall be required to bear all of the costs incurred by the Company including, but not limited to, the following: (a) investigations, (b) inspections, (c) costs of prosecution including legal fees, and (d) installation of any protective equipment deemed necessary by the Company. Furthermore, where tampering with the Company's or Customer's facilities results in incorrect measurement of the Service, the Customer shall pay for such Service as the Company may estimate from available information to have been used on the premises but not registered by the Company's meter or meters. Tampering with the Company's facilities is punishable by fine and/or imprisonment under New Jersey law. (See NJAC 14:3-7.8)

6.05 Payment for Repairs or Loss: The Customer shall pay the Company for any damage to or any loss of Company's property located on the Customer's premises caused by the act or negligence of the Customer or his agents, servants, licensees or invitees or due to the Customer's failure to comply with the applicable provisions of this Tariff.

6.06 Service Disconnection and Meter Removal Authorized: A licensed electrician or an electrical contractor, upon notifying the Company, will be authorized to disconnect and permanently reconnect a single-phase secondary overhead service that is 200 amps or less. Disconnections or meter removals performed by persons other than authorized licensed electricians, authorized electrical contractors, or authorized Company personnel are prohibited and shall constitute tampering. (See Sections 6.07 and 6.08)

6.07 Reconnection of Service or Replacement of Meter: The Company shall have sole authority to reconnect a service or replace a meter. However, upon contacting the Company, a licensed electrician or electrical contractor may be authorized to reconnect a service or reinstall the meter upon completion of his work as provided in Section 6.06. (See Section 4.09)

6.08 Sealing of Meters and Devices: It is the practice of the Company to seal all meters. Service Entrance switches, wiring troughs, or cabinets connected ahead of meters or instrument transformers, will be sealed by the Company. When Service is introduced prior to the completion of the wiring, or where Service is discontinued, the Company or its designated agent may seal all Service equipment. No one except an authorized employee of the Company is permitted to remove a Company seal or padlock, except as provided in Section 6.06.

6.09 Power Disturbance Protection Service: The Company shall offer to provide the following to Customers which request power disturbance protection: (a) diagnostic services to identify the probable cause of electrical disturbance, (b) engineering analysis and design to develop a power conditioning solution, (c) electrical system modification and/or power conditioning equipment installation, and (d) maintenance of the power conditioning systems. Charges for such Service shall be not less than the actual cost to provide such Service. The Company shall not be liable for damage or injury arising from the improper use of power disturbance protection/conditioned power service, systems or equipment, or for any costs or damages attributable to injury or the loss of the Customer's business, production or facilities resulting from the failure of power disturbance protection/conditioned power service, systems or equipment.

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Section 7 - Suspension or Discontinuance of Service

7.01 Work on Company's Facilities: The Company may, upon reasonable notice when it can be reasonably given, suspend, curtail, or interrupt Service to a Customer for the purpose of making repairs, changes, or improvements to or in any of its facilities either on or off the Customer's premises.

7.02 Compliance with Governmental Orders: The Company may curtail, discontinue, or take appropriate action with respect to Service, either generally or as to a particular Customer, as may be required by compliance in good faith with any governmental order or directive, and shall not be subject to any liability, penalty, or payment, or be liable for direct or consequential damages by reason thereof, notwithstanding that such instruction, order or directive subsequently may be held to be invalid or in error. Verbal or written orders of police, fire, public health, or similar officers, acting in the performance of their duties, shall be deemed to come within the scope of this subsection. (See Sections 4.01 and 4.04)

7.03 Customer Acts or Omissions: The Company may, upon giving reasonable notice to the Customer when it can be reasonably given, suspend or discontinue Service and remove the Company's equipment from the Customer's premises for any of the following acts or omissions:

(a) Non-payment of any valid bill due from the Customer or the Customer's resident spouse for Service furnished by the Company at any present or previous location. However, non-payment for business Service shall not be a reason for discontinuance of residential Service, except in cases of diversion of Service. (See Section 3.08)
(b) Tampering with any of the Company's facilities. (See Section 6.04)
(c) Fraudulent representation or application in relation to the use of Service. (See Section 1.03)
(d) Moving from the premises, unless the Customer has requested the Company to continue Service at the Customer's expense. (See Section 2.06)
(e) Resale, transfer, or delivering any part of the Service supplied by the Company to others without the Company's permission. (See Section 1.05)
(f) Refusal or failure to make or increase an advance payment or credit deposit as provided for in this Tariff. (See Section 3.09)
(g) Refusal or failure to contract for Service when reasonably required by the Company to do so. (See Section 2)
(h) Connecting and operating equipment so as to produce disturbing effects on the Company's system or Service to other Customers. (See Section 1.06)
(i) Refusal or failure to comply with any provisions of this Tariff.
(j) Where, in the Company's opinion, the condition of the Customer's installation presents a hazard to life or property.
(k) Refusal or failure to correct any faulty or hazardous condition of the Customer's installation.
(l) Refusal of reasonable access to Customer's premises for necessary purposes in connection with rendering of Service, including meter installation, reading or testing, or the maintenance or removal of the Company's property.

Failure by the Company to exercise its rights shall not be deemed a waiver thereof. (See NJAC 14:3-3A.1)

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Section 7 - Suspension or Discontinuance of Service

7.04 Reconnection of Service: When Service has been discontinued by reason of any act or omission or default of the Customer, the Company will not restore service to the Customer's premises until the Customer has made proper application therefor and has rectified the condition or conditions that caused the discontinuance. It is further required that the Customer shall have paid all amounts due as provided in this Tariff including the Service Charge of the applicable Service Classification to reimburse the Company in part for the cost of special handling of the account and of the special costs associated with the disconnection and reconnection of Service.

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Section 8 - Service Connections

8.01 General: This Section governs situations in which the Company's distribution lines and facilities are of adequate capacity to serve the Customer's load and are located adjacent to the Customer's premises. In these situations, the connection between the Company's system and the Customer's installation shall be made by the Company and established in accordance with the provisions of this Section.

8.02 Overhead Service Connection: The Company will install, connect, and maintain at its own cost and expense not more than one Service Drop for each contract location. The Company shall not be required to install a Service Drop where its length would exceed the safe distance over which a single span of Service Drop conductors can be placed.

8.03 Underground Secondary Service Connection (other than a manhole duct system) to Serve an Individual Residential Customer/Applicant: (a) A residential Customer or Applicant electing an underground Service Connection instead of an overhead Service Connection can elect to install such connection at his/her own cost and expense in accordance with the Company's specifications for such construction. At the Customer's option, the Company will install and connect such underground Service Connection, upon the Customer making a non-refundable contribution, as described in (b) below. In either case, the Company will assume ownership and responsibility for maintenance, including replacement when appropriate, at the Company's expense, of the underground Service Connection upon connection to the Company's system (subject to receipt of requisite easements, rights of way or the like, at no cost to the Company). In addition, at the Customer's option, the Company will assume ownership and responsibility for maintenance, including replacement when appropriate, at the Company's expense, of all private residential underground Service Connections installed prior to the date of this tariff sheet (subject to receipt of requisite easements, rights of way or the like, at no cost to the Company). In connection with any Company work performed under this Section 8.03, whether on Company-owned or Customer-owned facilities, the Company must first be granted the right by the Customer to trim or remove vegetation and to remove structures or other obstructions that interfere with such work and the Company will not be responsible for the costs of repair, replacement or restoration thereof.

(b) The non-refundable contribution will be equal to the predetermined unit cost differential of furnishing such facilities underground instead of overhead. If the Customer provides the trench, the underground Service Connection charge will be credited accordingly.

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Section 8 - Service Connections

8.04 Underground Distribution Service Connection to Serve a Non-Residential Customer: Where a non-residential Customer or Applicant elects such underground Service Connection instead of an overhead Service Connection, or where an overhead or secondary network system is not available, the Customer or Applicant, or the Company at the Customer or Applicant's discretion, must install such connection at the Customer or Applicant's own cost and expense in accordance with the Company's specifications for such construction. The Service Connection will be made by the Company, and shall be owned and maintained, and when necessary, relocated in accordance with the Company's specifications, by Customer at the Customer's own cost and expense.

8.05 Underground Distribution Service Connection (other than a manhole duct system) in Residential Subdivision: Where distribution circuits have been extended underground pursuant to Tariff Part II, Section 10, the Service Connection shall be installed underground as part of the entire electrical system for the development upon payment of the applicable charges computed in accordance with Appendix A of these Standard Terms and Conditions.

8.06 Conventional Underground Service Connection (Secondary Network System): If a Customer's or Applicant's facility is located in a designated network system, one conventional underground Service Connection to each contract location will be provided by the Company without cost to the Customer which shall terminate at a point not more than 30 feet distant from the curb, measured at right angles to the curb, nearest the point of connection to the Customer's facilities, provided, however, that the Company will not supply a Service Connection in whole or in part under or within a building except that portion extending through the building wall. When the required length of Service Connection exceeds the foregoing, the Customer shall have the option of terminating his facilities at either (1) a splice box acceptable to the Company installed, owned, and maintained by the Customer at a point within the distance limit described above, or (2) at the discretion of the Company, in the nearest available splice box or manhole provided in and as part of the Company's normal underground distribution system. All connections between the Customer's and Company's facilities shall be made by the Company.

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Section 9 - General Interconnect Requirements for On-Site Generation

9.01 The following requirements and standards for connection of generating facilities located on Customer's premises to the Company system shall be met to assure the integrity and safe operation of the Company system with no deterioration to the quality and reliability of service to other Customers. The operation of the generation facility should be done in a competent manner, such that the Company system as a whole is protected.

9.02 All small power producers or cogenerators shall make application to the Company for approval to interconnect their facilities with the Company system.

9.03 The Company shall require the following as part of the application:

(a) Plans and specifications of the proposed installation.
(b) Single line diagram and details of the proposed protection schemes.
(c) Instruction manuals for all protective components.
(d) Component specification and internal wiring diagrams of protective components if not provided in instruction manuals.
(e) Generator data required to analyze fault contributions and load current flows including, but not limited to, equivalent impedances and time constants.
(f) All protective equipment's ratings if not provided in instruction manuals.
(g) Evidence of insurance satisfactory to the Company.
(h) An agreement to indemnify and hold harmless the Company from any and all liability or claim thereof for damage to property, including property of the Company and injury or death to persons resulting from or caused by the presence, operation, maintenance or removal of such installation.

9.04 The Company shall within 30 days from the receipt of all required data from the Applicant either approve or reject in writing the application for connection to the Company system. Rejection of an application shall state with specificity the reasons for such rejection. Connection to the Company system will be permitted only upon obtaining the formal approval of the Company. The Company may require the execution of a formal application form and/or interconnection agreement by the customer.

9.05 The installation of the generation facilities must be in compliance with the requirements of the National Electrical Code and all applicable local, State and federal codes or regulations. The installation shall be undertaken and completed in a workmanlike manner, and shall meet or exceed industry acceptance standards of good practice. The provisions of the National Electrical Safety Code and the standards of the Institute of Electrical and Electronics Engineers, National Electrical Manufacturers Association and the American National Standards Institute shall be observed to the extent that they are applicable. Prior to connection, the Company must be provided with evidence that electrical inspection by an authorized inspection agency indicates that the above items were completed in a manner satisfactory to the Company.

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Section 9 - General Interconnect Requirements for On-Site Generation

9.06 The generation facility shall have the following characteristics:

(a) Interconnection voltage shall be compatible and consistent with the system to which the Company determines the generation facility is to be connected.
(b) The generation facility shall produce 60 Hertz sinusoidal output compatible with the Company system to which the facility is to be connected.
(c) The generation facility must provide and maintain automatic synchronization with the Company system to which it is to be connected.
(d) The break point between the generation facilities producing single-phase or three-phase output shall be in accordance with existing Company motor specifications or as otherwise specified by the Company.
(e) At no time shall the operation of the facility result in excessive harmonic distortion of the Company wave form. Total harmonic distortion greater than 5% shall be deemed excessive and shall result in disconnection of the facility from the Company system.
(f) The installation of power factor correction ("PFC") capacitors at the facility may be required under conditions to be determined by the Company when necessary to assure the quality and reliability of service to other Customers. The cost of PFC capacitors shall be borne by the Customer.
(g) The cost of supplying and installing 15-minute integrated generation output metering, and any other special facilities or devices occasioned by the generation facility which the Company may deem necessary on its system, such as telemetry and control equipment, shall be borne by the Customer.

9.07 The Customer shall provide automatic disconnecting devices with appropriate control devices which will isolate the facility from the Company system within a time period specified by the Company for, but not necessarily limited to, the following conditions:

(a) A fault on the Customer's equipment.
(b) A fault on the Company system.
(c) A de-energized Company line to which the customer is connected.
(d) An abnormal operating voltage or frequency.
(e) Failure of automatic synchronization with the Company system.
(f) Loss of a phase or improper phase sequence.
(g) Total harmonic content in excess of 5%.
(h) Abnormal power factor.

The devices shall be so designed and constructed to prevent reconnection of the facility to the Company system until the cause of disconnection is corrected.

9.08 The Company shall reserve the right to specify settings of all isolation devices which are part of the generation facility.

Section 9 - General Interconnect Requirements for On-Site Generation

9.09 The Company shall require initial inspection and testing as well as subsequent inspection and testing of the facility's isolation and fault protection systems at the Customer's expense on an annual basis. Maintenance of these systems must be performed and documented by the customer at specified intervals to the satisfaction of the Company. The Company shall reserve the right to disconnect the customer and/or the generation equipment from the Company system for failure to comply with these inspections, testing and maintenance requirements.

9.10 The Customer is solely responsible for providing adequate protection for the equipment located on the Customer's side of the interconnection system. This protection shall include, but not be limited to, negative phase sequence voltage on three-phase systems.

9.11 The Customer shall provide a Company-controlled disconnecting device providing a visible break on the Company side of the interconnection system. The Company shall require that this device accept a Company-provided padlock. The Company may also require manual operation of the device when required. The Company shall require this device to be labeled "Cogeneration Disconnection Switch" and located outside the facility such that 24-hour access is possible.

9.12 The Customer shall agree to grant access to the Company's authorized representative during any reasonable hours to install, inspect and maintain the Company's metering equipment.

9.13 The Customer must satisfy, and shall be subject to, all terms and conditions of the Company's Tariff for Service.

9.14 No wind generator, tower structure or device shall be installed at a location where, in the event of failure, it can fall in such a manner as to contact, land upon, or interfere with any Company lines or equipment.

9.15 The Customer shall maintain or cause to be maintained the generator and its associated structures, wiring and devices in a safe and proper operating condition so that the installation continues to meet all the requirements contained herein.

9.16 When and if any controversy arises as to the interpretation and application of these requirements and standards, the matter may be referred to the BPU for determination.

9.17 The Company reserves the right to modify or replace the Customer's service meter to prevent reverse registration from the customer's generation facility. Customers desiring to sell power to the Company should refer to Rider QFS - Cogeneration and Small Power Production Service.

Section 10 – Extension of Company Facilities (NJAC 14:3-8)

10.01 General Information: Where a line extension is necessary to provide Service to a Customer or Applicant or group of Customers, and where the request is for an extension of Company facilities to serve new customers, or where the request is for an expansion, upgrade, improvement, or other installation of plant and/or facilities by an Applicant, the procedures set forth in this Section 10 shall be utilized as a guide to determine the extent of any refundable deposit or non-refundable contribution, which may be required from the Customer or Applicant pursuant to NJAC 14:3-8. The Company shall not be precluded from entering into a mutually favorable agreement with the Customer or Applicant when it is deemed that a portion of the investment is for purposes of system improvement. This Section 10 does not apply to installation of special facilities or back-up systems which are not normally supplied by the Company. When such facilities or back-up systems are requested by the Customer, Section 4.05 shall be applicable.

For purposes of this Section 10, the following defined terms are exclusively for use in connection with this Section. Other definitions, as provided in Part I of the Company's Tariff for Service, may also be applicable to any Applicant under this Section and, where appropriate, should be used in conjunction with these terms.

The term "Applicant" means a person or an entity that requests Extension Service from the Company. An Applicant may or may not be the End User or Customer of the Company.

The term "Extension Service" refers to the construction or installation of electric distribution plant and/or facilities by the Company used to convey Service from existing or new plant and/or facilities (and includes the new plant and/or facilities themselves) to a structure or property for which the Applicant has requested Service in response to (i) an application for Extension Service from an Applicant to serve new customer(s) and/or (ii) an application for Extension Service requesting expansion, upgrade, improvement, or other installation of plant and/or facilities to serve existing customer(s). The Extension Service begins at existing plant and/or facilities and ends at the point of connection to or with the Service Connection, and includes the meter.

The term "Extension Cost" refers to the cost of construction and installation of the Extension Service based on the Company's "standard least cost design" criteria, using the Company's unitized or actual cost for materials and labor (both internal and external) employed in the design, construction, and/or installation of the Extension Service, including, but not limited to, Service Connection (subject to Section 8), metering-related costs, and including overheads directly attributable to the work, and the loading factors, such as those for mapping and design. Extension Costs may be apportioned based upon load depending on factors such as the Applicant's needs as compared to the Company's need to enhance or improve reliability, or the needs of other Applicant(s) who may be using the same facilities.

The term "refundable deposit" pertains to the non-interest bearing monies, which must be increased in accordance with Part II, Section 3.14 to provide for the associated income tax liability, that the Applicant must advance prior to the start of construction. The entire refundable deposit amount is subject to refund as set forth herein. Any portion of the refundable deposit remaining after the tenth year of service, as provided in this Section 10, is no longer subject to refund, and becomes the property of the Company. In no event shall more than the original refundable deposit be refunded.

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Section 10 – Extension of Company Facilities (NJAC 14:3-8)

10.01 General Information: (Continued)

A “non-refundable contribution," which the Applicant must pay in full prior to construction, becomes the property of the Company and is not subject to refund. All non-refundable contributions must be increased in accordance with Part II, Section 3.14 to provide for the associated income tax liability.

The term "distribution revenues" utilized in this Section 10, as defined by the BPU, shall mean the total revenue, plus related sales and use tax, collected by a regulated entity from a Customer, minus basic generation service charges, plus sales and use tax on the basic generation service charges, and, unless included with basic generation service charges, transmission charges derived from Federal Energy Regulatory Commission (FERC) approved transmission charges, plus sales and use tax on the transmission charges, assessed in accordance with the Company’s Tariff for Service. This definition refers to the total amount of Delivery Service charges (which include Sales and Use Tax) from customer(s), as provided in the applicable rate schedule in Part III of the Company’s Tariff for Service.

The term "underground distribution" refers to buried distribution conductors with associated above-grade equipment.

The term "conventional underground" refers to a secondary network installed in a complete manhole and duct system with all equipment below grade level and is generally located in central sections of the more urban communities.

The term “standard least cost design” refers to the Company’s design criteria for an overhead extension of its facilities, which is based upon then-existing Company specifications as contained in the Company’s Construction Standards, Material Specifications, and Distribution Engineering Practices. These standards are developed in compliance with the current edition of the National Electrical Safety Code in order to provide reliable electric service in a cost-effective manner.

The term “alternate design” refers to an Applicant’s request for Extension Service in a particular manner that exceeds the Company’s “standard least cost design” criteria, including, but not limited to, underground requirements and the removal of existing facilities. An example of an “alternate design” requested by an Applicant would be the installation of a pad-mounted transformer adjacent to a parking lot behind a building, rather than at the front corner closest to the Company’s existing distribution circuit. The difference in cost between the “alternate design” and the “standard least cost design” shall, in all cases, be paid in full by the Applicant as a non-refundable contribution.

Section 10 – Extension of Company Facilities (NJAC 14:3-8)

10.02 Rights-of-Way: The Company shall not be required to extend or relocate its facilities for the purpose of rendering Extension Service to Applicants until rights-of-way or easements satisfactory to the Company have been obtained from government agencies and property owners to permit the installation, operation, and maintenance of the Company's lines and facilities. In connection with granting to, or obtaining for, the Company, without charge, such rights-of-way or easements as necessary for the Company's lines and facilities to be placed upon, over, across, or under property as necessary to provide the Extension Service, Applicants requiring Extension Service shall perform all initial vegetation clearance and trimming. The Company shall also be granted the right to trim or remove vegetation and to remove structures or other obstructions that might subsequently interfere with such lines and facilities, the right of access and entry without notice for Company agents and equipment necessary in the exercise of privileges under the grant, and the right to use and extend the Company's lines and facilities, and install additional lines and facilities, as deemed necessary by the Company in order to provide Service to other Customers. Any right-of-way or permit fees, either initial or recurring, or charges in connection with rights-of-way for providing Extension Service to an Applicant, shall be paid for by the Applicant.

10.03 Extension Service to the Boundary of a Subdivision (Residential and Non-Residential): Such an extension shall normally be provided overhead on public right-of-way and/or private property based upon the Company's standard least cost design criteria, but shall not be provided underground on public right-of-way unless required of, or approved by, the Company.

If the Applicant requests Extension Service that exceeds the Company's standard least cost design criteria, and the Company approves the request, the Applicant shall be required to make a non-refundable contribution equal to the additional cost of the alternate design.

The Company may require a refundable deposit of the Extension Cost, prior to construction, to be refunded as provided in Sections 10.04 or 10.05, as applicable.

Section 10 – Extension of Company Facilities (NJAC 14:3-8)

10.04 Extension Service within a Residential Subdivision: Such an extension shall not be provided overhead. It shall be provided underground based upon the Company's underground design criteria, on public right-of-way and/or private property. This Section is applicable only for new, predominantly residential areas where all the applicable provisions of the Standard Terms and Conditions of this Tariff and any applicable provisions of the New Jersey Administrative Code (NJAC) are complied with.

The Applicant shall make a non-refundable contribution for the construction cost differences between the overhead and the underground design in accordance with Appendix A of Part II of this Tariff.

If the Applicant has not obtained sale contracts for at least 20% of the total units, the Company may require a refundable deposit equal to the Extension Cost using the total unitized cost for the equivalent overhead construction.

Any refundable deposit received from the Applicant will be refunded as follows: One year after the first connection of a completed premise occupied by a bona fide owner or a responsible tenant who has entered into a contract with the Company for Service, the Company will refund a sum equal to ten times total actual distribution revenues from all such bona fide owner(s) or responsible tenant(s) during such contract year, up to (but not in excess of) the refundable deposit amount. Refunds in subsequent years, for up to nine additional years after the first year, will be equal to ten times the positive difference after subtracting: 1) the highest total actual distribution revenues that was used for calculating the refund in any previous year, from 2) the total actual distribution revenues from all such bona fide owners or responsible tenants during each such subsequent year, up to (but not in excess of) the remaining refundable deposit amount.

10.05 Extension Service to Serve Non-Residential Customers (including within Non-Residential Subdivisions), Multi-unit Residential Apartment Buildings, and Three-Phase Individual Residential Customers: Such an extension will be provided overhead based upon the Company's standard least cost design criteria, but may be provided underground as an alternate design, but shall not be provided underground on public right-of-way, unless required of, or approved by, the Company. When Extension Service is provided underground pursuant to this Section 10.05, the Applicant, or the Company at the Applicant's discretion (and at the Applicant's own cost and expense consistent with Section 10.01), shall provide all trenching and backfill in accordance with the Company's specifications.

If the Applicant requests Extension Service that exceeds the Company's standard least cost design criteria, and the Company approves the request, the Applicant shall be required to make a non-refundable contribution equal to the additional cost of the alternate design.

The Company may require a refundable deposit equal to the Extension Cost. The refundable deposit under this Section 10.05 shall be eligible for refund, up to (but not in excess of) the refundable deposit amount, as follows: At the end of the first year, the Company will refund from the refundable deposit an amount equal to ten times the total actual distribution revenues billed during that period. At the end of each subsequent year, for an additional nine years, a refund will be equal to ten times the positive difference after subtracting: 1) the highest total actual distribution revenues that was used for calculating the refund in any previous year, from 2) the total actual distribution revenues billed during each such subsequent year, up to (but not in excess of) the remaining refundable deposit amount.

Section 10 – Extension of Company Facilities (NJAC 14:3-8)

10.06 Extension Service to Serve a Single-Phase, Individual Residential Customer: Such an extension shall be provided overhead based upon the Company's standard least cost design criteria, and may be provided underground as an alternate design, but shall not be provided underground on a public right-of-way. When Extension Service is provided underground pursuant to this Section 10.06, the Applicant shall be required to provide all trenching and backfill in accordance with the Company's specifications.

The difference in cost between the alternate design and the Company's standard least cost design shall be paid in full by the Applicant as a non-refundable contribution.

When provided overhead on a public right-of-way, the Extension Service will be provided without charge or deposit requirement. When provided overhead on private property, the Extension Service will be provided without charge when the Extension Cost, based on the distance measured from the property line to the dwelling location, does not exceed ten times the estimated annual distribution revenues. A refundable deposit may be required from the Applicant for any Extension Cost in excess of ten times the estimated annual distribution revenues.

The refundable deposit under this Section 10.06 shall be eligible for refund, up to (but not in excess of) the refundable deposit amount, as follows: At the end of the first year, the Company will refund from the refundable deposit an amount equal to ten times the total actual distribution revenues billed during that period, less the estimated annual distribution revenues (used as the basis for the initial refundable deposit calculation). At the end of each subsequent year, for an additional nine years, a refund will be equal to ten times the positive difference after subtracting: 1) the highest total actual distribution revenues used for calculating the refund in any previous year, from 2) the total actual distribution revenues billed during each subsequent year, up to (but not in excess of) the remaining refundable deposit amount.

10.07 Extension Service within Conventional Underground Area: Such an extension for 600 volt systems necessary on public right-of-way shall be installed without charge or deposit requirement. Such extensions shall not be provided on private property or for other than 600 volt systems.

10.08 Extension Service Initiation: The Company shall not commence construction of the Extension Service until (a) it has received and accepted an application for service; (b) the Applicant has completely executed appropriate contracts for Service, including, but not limited to, Extension Service as set forth in this Section 10; (c) the Applicant has paid any and all associated Extension Costs or other charges, whether by way of a refundable deposit or a nonrefundable contribution as applicable; and (d) the Applicant requesting the Extension Service has furnished to the Company satisfactory rights-of-way over, across, through, in and/or on property that are acceptable to the Company and necessary for the construction, maintenance and operation of the Extension Service.

10.09 Grading Requirements: The Applicant shall perform or arrange and pay for all Company-directed rough grading in accordance with the Company's specifications for underground lines and facilities as said specifications shall be modified by the Company from time to time. The Company's specifications are available from the Company upon request.

10.10 Exceptions: No deviations from the Company's standard construction practices shall be permitted without the Company's approval. Any Company-approved deviations from said construction practices shall be at the Applicant's sole expense.

Section 11 – Third Party Supplier Standards

11.01 Tariff Governs: The Company's BPU-approved Third Party Supplier Agreement and Customer Account Services Master Service Agreement will be governed by reference to this Tariff for Service.

11.02 Uniform Agreement: The Company shall offer the same BPU-approved Third Party Supplier Agreement and Customer Account Services Master Service Agreement to all licensed entities that seek to serve as Alternative Electric Suppliers in the Company's service area by providing electric generation service to Customers located therein.

11.03 Procedure for Agreement Modification: Modifications of the Supplier Fees and Charges contained in the Company's Third Party Supplier Agreement shall be made in accordance with applicable BPU Orders, including the BPU Order dated August 17, 1999 (Docket No. EO97070460). Other modifications to the Company's Third Party Supplier Agreement must be approved by the BPU in accordance with the standards set forth in the aforementioned Order, as follows, or as otherwise directed by the BPU.

The Company shall file a written request for BPU approval of intended modifications (the "Request") with the Board. The date of filing shall be referenced herein as the "Filing Date." A copy of the filing shall simultaneously be provided, by regular mail, facsimile, hand delivery, or electronic means, to the Division of the Ratepayer Advocate, Public Service Electric and Gas, Conectiv, Rockland Electric, and to all BPU-licensed Alternative Electric Suppliers (using a list of addresses for the Alternative Electric Suppliers that shall be maintained by the BPU and made available to the Company). The mode(s) of transmission shall be selected to effectuate actual delivery of the copies within 48 hours of filing with the Board.

Should the Ratepayer Advocate or any BPU-licensed Alternative Electric Supplier wish to contest the Request, the contesting entity must file its reasons for contesting the Request, in writing, with the BPU and simultaneously serve copies thereof upon the Company and the Ratepayer Advocate. This must be done within 17 days of the Filing Date. Service upon the Company shall be made by way of the Company representative who filed the Request.

Within 45 days of the Filing Date, the BPU may issue a Suspension Order stating that the Request requires further study. Such determination would put the Request on hold, pending future action by the Board.

If the BPU does not take action on the Request within 45 days of the Filing Date, the Company may implement the intended modifications, although the BPU retains the authority to make a determination on the Request in the future.

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Section 12 – Net Metering Installations

12.01 General: For the purpose of this Section of the Tariff for Service a Customer-generator is an electricity customer such as an industrial, commercial or residential customer that generates electricity using Class 1 renewable resources as defined in NJAC 14:8-1.2 on the customer's side of the meter. Net metering, as defined in Section 12.02 below, provides for the billing or crediting, as applicable, of energy usage by measuring the difference between the amount of electricity delivered by the Company to a Customer-generator, as defined in Section 12.02 below, in a given Billing Month and the electricity delivered by a Customer-generator into the Company distribution system. The Company reserves the right to select and supply the type of meter(s) that will enable the net metering of electricity as described above.

The Customer generator shall be responsible for all interconnection costs as defined in NJAC 14:8-5.7 et seq., which shall be in addition to any other charges applicable to meet service requirements. For customers eligible for Net Metering the term usage as applied in Section 2.05 shall mean net usage as determined by Net Metering. It is the Customer-generator's responsibility to know all of the rules associated with the provision of net metering service.

12.02 Limitations and Qualifications for Net Metering: "Net metering" means a system of metering and billing for electricity in which the Company 1) credits a customer-generator at the full retail rate for each kilowatt-hour produced by a Class 1 renewable energy system installed on the customer-generator's side of the electric revenue meter, up to the total amount of electricity used by that customer-generator during an annualized period determined under NJAC 14:8-4.3 and 2) compensates the customer-generator at the end of the annualized period determined under NJAC 14:8-4.3 for any remaining credits, at a rate equal to the avoided cost of wholesale power. To qualify for Net Metering, a Customer-generator must generate Class 1 renewable energy as defined in NJAC 14:8-1.2. The Company will offer net metering to any customer that generates Class 1 renewable electricity on the customer's side of the meter provided that the generating capacity of the Customer-generator's facility does not exceed the amount of electricity supplied by the Company over an Annualized period (as defined in NJAC 14:8-4.3).

12.03 Limitations and Qualifications for Aggregated Net Metering (N.J.S.A. 48:3-87e(4)) and (N.J.A.C 14:8-7): To qualify for Aggregated Net Metering a customer must be: a state entity, school district, county, county agency, county authority, municipality, municipal agency, or municipal authority that has multiple facilities with metered accounts to be known collectively as the "Aggregated Meters." The Aggregated Meters must be: located within the Company's territory; served under the same rate schedule; all served by either Basic Generation Service or by the same Third Party Supplier; and located within the customer's territorial jurisdiction or, for a State entity, located within 5 miles of one another. One of the Aggregated Meters must operate a Class 1 solar electric power generation system using a net metered account as defined in Section 12.02, Limitations and Qualifications for Net Metering, except for the annualized electric generation capability limitation. The Qualified Customer-Generator must be located on property owned by the customer. The size of the Qualified Customer-Generator for Aggregated Net Metering is defined in Section 12.03.a, Customer-Generator Sizing Qualifications for Aggregated Net Metering.

a) **Customer-Generator Sizing Qualifications for Aggregated Net Metering:** The annualized electric generation capability of the customer's solar generating system, located at the net metered location cannot exceed the amount of electricity supplied by the electric power supplier or basic generation service provider to all of the Aggregated Meters over an annualized period. The Aggregated Meters used to determine the maximum annualized electric generation capability of the customer's solar generating system may not be used to determine the maximum annualized electric generation capability of other aggregated net metered facilities nor become a Qualified Customer-Generator as defined in Section 12.02, Limitations and Qualifications for Net Metering.

Section 12 – Net Metering Installations

12.03 Limitations and Qualifications for Aggregated Net Metering (N.J.S.A. 48:3-87e(4)) and (N.J.A.C 14:8-7): (Continued)

b) **Billing for Aggregated Net Metering**: The Qualified Customer-Generator will be billed as defined in Section 12.07, Net Metering Billing. However, Section 12.06, Net Metering Billing will not apply to the other Aggregated Meters and those meters will continue to be billed at the full retail rate pursuant to the applicable rate schedules.

c) **Incremental Costs Associated with Aggregated Net Metering:** All incremental costs incurred by the Company resulting from the implementation of Aggregated Net Metering shall be recovered from Aggregated Net Metering customers.

12.04 Limitations and Qualifications for Remote Net Metering (BPU Docket No. QO18070697, Order dated September 17, 2018):

The Clean Energy Act, P.L. 2018, Chapter 17, Section 6 required the BPU to establish an application and approval process to facilitate Remote Net Metering in which a public entity certified to act as a host customer with a solar electric energy project may allocate credits to other public entities within the same electric public utility service territory. To qualify for Remote Net Metering a customer must be a public entity, which is a State entity, school district, county, county agency, county authority, municipality, municipal agency, municipal authority or public university that has completed the BPU-approved application process and received BPU approval for certification as a participant eligible to receive Remote Net Metering credits. A host customer is a public entity that proposes to host a solar electric generation facility on its property. The entities designated to receive credits are considered to be receiving customers that are public entities located in the same electric distribution company (“EDC”) territory as the host customer. Both the host customer and the receiving customer must be a customer of record of JCP&L, and there may be no more than 10 receiving customer accounts per host.

Eligible public entities must follow the established application and approval process to certify public entities to act as a host customer for Remote Net Metering, requiring submittal of the BPU-approved form of “Public Entity Certification Agreement” used by the host customers and receiving customers which shall be fully executed and provided to the Company, reviewed by the Staff of the BPU and approved by the BPU prior to the application of any Remote Net Metering credits. The Public Entity Certification Agreement is available on the New Jersey Clean Energy Program website as well as the Company’s website in the section dedicated to information regarding net metering and interconnection processes. The standard form “Public Entity Certification Agreement” must be fully executed by the host customer and each receiving customer, be accompanied by the BPU-approved standard form of Interconnection Application (Part 1) as used for all net metered projects and be delivered to both BPU Staff and the Company. The Company and BPU Staff will review the Public Entity Certification Agreement for administrative completeness. Within 10 days, the Company will provide its input to BPU Staff, whereupon BPU Staff will issue a notice of its findings to the contact person listed on the form. Following the issuance of a notice of administrative completeness, the Company will have 20 business days to review the application for eligibility and feasibility, including the proposed system size and all account information and make a recommendation to BPU Staff to approve or deny. In the case of a recommendation of denial, the Company will provide to BPU Staff a description of the deficiencies and potential means to correct the deficiencies. BPU Staff will present the fully executed “Public Entity Certification Agreement” and Part 1 of the Interconnection application to the BPU with a recommendation for approval or denial.

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Section 12 – Net Metering Installations

Host Customer Solar Electric Generator Sizing for Remote Net Metering: The size of a host customer's solar electric generation facility shall be limited to the installed capacity that can produce electricity on an annual basis in an amount not to exceed the total average usage of the host customer's electric accounts with the Company. The host customer is not required to use more than one account for purposes of sizing the solar electric generation facility. However, the solar facility must be located on property containing at least one Company electric meter for the host customer. The host customer is required to identify which account(s) to use to calculate the total average usage for the previous 12 months of consumption in kWhs. The total quantity of annual, historic consumed kWh will be divided by (i) the number of accounts, if more than one account is used, and (ii) 1,200 annual kWh per kilowatt ("kWdc") to arrive at the maximum capacity for the solar electric generation facility in kWs.

Billing and Credits for Remote Net Metering: No more than 10 receiving accounts may be party to a Public Entity Certification Agreement and not less than 10% of the solar electric generating facility output may be allocated to an individual receiving account. The terms and conditions of the Public Entity Certification Agreement, including all designated receiving accounts and their associated percentage of output allocations, shall be fixed throughout the annualized period with the exception of a once per annum opportunity to reallocate upon BPU Staff's approval of a revision to a Public Entity Certification Agreement, which is re-executed with all parties' approval, including the Company. The host customer shall agree to the installation of a revenue grade production meter at its expense as specified by the Company, to record the solar generation at the host site. On a monthly basis, the Company shall use the metered kWh data produced by the solar electric generation facility on the host customer property to calculate the credits due to receiving customers. The monthly output will be allocated to receiving customers according to the percentage allotments indicated on the Public Entity Certification Agreement. The value of a Remote Net Metering credit will reflect a rough approximation of the generation, transmission and distribution value of a kWh produced by the solar electric generation facility. Each credited kWh for a receiving customer shall offset the variable kWh charges of a receiving customer(s) except for the SBC charge. No fixed, demand ($/kW), customer or SBC charges shall be offset by a remote net metering credit. On a monthly basis, the Company will credit an apportioned amount of kWh output from the solar facility in the form of kWh to be deducted from the kWh consumed by the receiving customers according to the percentage allotments indicated on the Public Entity Certification Agreement. The apportioned amount of solar electricity generated in kWh, the gross amount of electricity consumed and the net amount of kWh after credit allocation will be identified on the monthly electric bills of the designated receiving customer account. The receiving customers will be charged the SBC amounts attributable to the apportioned credit kWh. The application of an annualized period as currently used in the net metering rules at N.J.A.C. 14:8-4.2 shall apply to remote net metering. Any excess generation for an individual receiving customer account after a monthly credit allocation shall be carried over to the next month within the annualized period. If an individual receiving customer account holds credits at the end of an annualized period, the account shall be trued up consistent with current net metering practice, with excess kWh compensated at the average annual LMP in the Company's transmission zone.

Remote Net Metering customers shall be responsible for all interconnection costs as described in Section 12.01

Section 12 – Net Metering Installations

12.05 Installation Standards: A Customer-generator shall comply with the requirements of the Company which are set forth in detail in the Application/Agreement Parts 1 and 2 for Level 1 Projects or the Interconnection Application and Agreement for Level 2 or Level 3 Projects both of which are approved by the New Jersey Office of Clean Energy and available at www.firstenergycorp.com. In addition, the Customer-generator shall be responsible for meeting all applicable safety and power quality standards as set forth below.

The Customer-generator's facility shall comply with all applicable safety and power quality standards specified by the National Electrical Code, Institute of Electrical and Electronics Engineers, and accredited testing institutions, such as Underwriters Laboratories. The Customer-generator's facility should be constructed and installed in accordance with the State of New Jersey Uniform Construction Code requirements for electrical installations, UL 1741 and the IEEE Standard 1547. Net Metering systems served by network distribution systems, shall comply with standards established by the Company and approved by the BPU in addition to the aforementioned applicable safety and power quality standards and all other requirements in NJAC 14:8-5.2 et seq

12.06 Initiation of Service: Prior to interconnecting with the Company's distribution system the Customer-generator is required to provide the Company with an Interconnection Application/Agreement Parts 1 and 2 for Level 1 projects or an Interconnection Application and Agreement for Level 2 or Level 3 Projects and must also pay all appropriate charges as detailed in these applications. Additionally, the Company may, at its option, inspect the interconnection prior to the initiation of Net Metering service.

Initiation of service will become effective on the Customer-generator's first regularly scheduled meter reading date that is at least twenty (20) days after the Customer-generator elects to take service under or to be billed under or in accordance with this provision, by executing an Interconnection Application, but in no case prior to the installation of the necessary meter(s), and shall terminate at a regularly scheduled meter reading date that is at least twenty (20) days following the receipt by the Company of Customer-generator's notification of termination or from the date that the Company determines that the customer-generator is no longer eligible for net metering service pursuant to NJAC 14:8-4.1 et seq.

12.07 Net Metering Billing: In any Billing Month during an Annualized period, where the amount of electricity delivered by the Customer-generator plus any kilowatt-hour credits held over from the previous Billing Month or Billing Months exceeds the electricity supplied by the Customer-generator's electric supplier or basic generation service provider, as applicable, the excess kilowatt-hours shall be credited to the Customer-generator in the next Billing Month during the Annualized period. At the end of the Annualized period, the Customer-generator will be compensated for any remaining credits by the Customer-generator's electric supplier or basic generation service provider, as applicable, at the avoided cost of wholesale power (as defined at NJAC 14:8-4.2).

A Customer-generator shall have a one-time opportunity to select a Billing Month as the start of the Customer-generator's Annualized period. This selection will become effective on the first regularly scheduled meter reading date that is at least twenty (20) days after the Customer-generator notifies the Company of the Customer-generator's selection under the one-time opportunity provided in NJAC 14:8-4.3 (f) – (j).

In the event that a Customer-generator changes suppliers, the electric power supplier or basic generation service provider with whom service is terminating shall treat the end of the service period as if it were the end of the Annualized period and shall compensate the Customer-generator for any remaining credits at the avoided cost of wholesale power.

12.08 Program Availability: The Company may be authorized by the BPU to cease offering net metering whenever the total rated generating capacity owned and operated by Customer-generators on a Statewide basis equals 5.8 percent of total annual kilowatt-hour sales in the State.

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Section 13 – Community Solar Energy Pilot Program

13.01 General:

The Community Solar Energy Pilot Program is open to customers of all rate classes who subscribe to community solar projects that are approved by the BPU. Community solar projects and customer subscribers to those approved projects must meet the following minimum requirements, and the full requirements defined in N.J.A.C. 14:8-9.1, *et seq.*, in accordance with N.J.S.A. 48:3-87.11. The program provides for the participation of customers of the Company in all rate classes as subscribers to BPU-approved community solar projects that are located within the service territory of the Company, but may be remotely located from the subscriber's electric service address, and receive a credit on their utility bills in accordance with their participation share. Existing solar projects may not apply to requalify as a Community Solar Energy Pilot Program project. The Pilot Program shall run for a period of no more than 36 months, divided into Program Year 1 (PY1), Program Year 2 (PY2), and Program Year 3 (PY3). PY1 shall begin February 19, 2019, and last until December 31, 2019. Subsequent program years shall begin on January 1 and last for the full calendar year. For each of the three program years, BPU staff shall initiate an annual application process. The annual capacity limit in the Company's service territory each year shall be calculated by the BPU by multiplying the Company's percentage of in-State retail electric sales by the total statewide capacity approved for that year. In PY1, this represented approximately 20.625 MW based upon the Company's 27.5% share of the 75 MW available statewide capacity. Any unallocated capacity at the end of a program year may be reallocated to subsequent program years. At least 40 percent of the annual capacity limit shall be allocated to low and moderate income community (LMI) solar projects. The application and criteria for selection of community solar projects is managed by the BPU. Only projects that are selected by the BPU will be eligible to participate in the Pilot Program. The capacity limit for individual community solar pilot projects is set at a maximum of five MWs per project, measured as the sum of the nameplate capacity in DC rating of all PV panels comprising the community solar facility. The minimum number of participating subscribers for each community solar project shall be set at 10 subscribers and the maximum number of participating subscribers for each community solar project shall be set at 250 subscribers per one MW installed capacity (prorated to project capacity). Each community solar project must be equipped with at least one utility grade meter to facilitate the recording of solar generation underlying the bill credit process.

13.02 Selected Definitions (N.J.A.C. 14:8-9.2):

"Community solar pilot project," "community solar project," or "project" refers to a community solar project approved by the BPU for participation in the Pilot Program, including, but not limited to, the community solar facility, project participants, and subscribers.

"Community solar subscriber organization" or "subscriber organization" means the entity, duly registered with the BPU that works to acquire original subscribers for the community solar project and/or acquires replacement subscribers over the lifetime of the community solar project and/or manages subscriptions for a community solar project. The community solar subscriber organization may or may not be, in whole, in part, or not at all, organized by the community solar developer, community solar owner, or community solar operator.

"Community solar subscriber" or "subscriber" refers to any person or entity who participates in a community solar project by means of the purchase or payment for a portion of the capacity and/or energy produced by a community solar facility. One electric meter denotes one subscriber.

"Community solar subscription" or "subscription" refers to an agreement to participate in a community solar project, by which the subscriber receives a bill credit for a portion of the community solar capacity and/or energy produced by a community solar facility. A subscription may be measured as capacity in kW and/or energy in kWh, ownership of a panel or panels in a community solar facility, ownership of a share of a community solar project, or a fixed and/or variable monthly payment to the project operator.

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Section 13 – Community Solar Energy Pilot Program

13.03 Subscription Requirements:

Community solar pilot project subscriptions shall not exceed 100 percent of the subscriber's historic annual usage, calculated over the past 12 months, available at the time of the application. In cases where a 12-month history is not available, the community solar subscriber organization shall estimate, in a commercially reasonable manner, a subscriber's load based on available history. No single subscriber shall subscribe to more than 40 percent of a community solar project's total annual net energy. Subscriptions are portable, provided that the subscriber remains within the original Company service territory as the community solar pilot project to which they are subscribed. Appropriate notice of the change in residence and/or location must be provided to the Company, no later than 30 days after the effective date of the change in residence and/or location. In cases of relocation, subscribers are entitled to one revision per move to their subscription size to account for a change in average consumption. Subscriptions may be sold or transferred back to the project owner or community solar subscriber organization by subscribers as specified in their subscription agreements. Subscribers may not sell or transfer a subscription to another party other than the project owner or community solar subscriber organization. A subscriber may not participate in more than one community solar project. It is the responsibility of the subscriber organization to verify that their subscribers are not already subscribed to another community solar project. The Company shall establish, in coordination with BPU staff, a standardized process by which community solar subscriber organizations can submit on a monthly basis the list of subscribers for a community solar project, and their respective participation shares. The Company shall apply the community solar bill credit to subscribers' utility bills in proportion to each subscriber's participation share, in conformance with the bill credit calculation method described below.

Additional details regarding JCP&L's subscription process may be found on the Company's website at www.firstenergycorp.com/supplierservices/nj/nj-solar-program.html.

13.04 Community Solar Bill Credits

Participating subscriber customers will receive a dollar-based bill credit for their subscribed percentage of the monthly kilowatt-hour output of the community solar project in proportion to the subscriber's share of the community solar project as indicated on the most recent list received from the subscriber organization. The monthly dollar credit on the subscriber's bill will be the equivalent of their subscription percentage of the community solar project monthly kilowatt-hour generation amount applied to all kilowatt-hour charges on the subscriber's bill, excluding all fixed and non-by-passable charges and SUT. The non-bypassable charges are the fixed monthly customer charge, all kW demand charges (if applicable), the SBC charge, the NGC charge and the ZEC charge. The value of the bill credit shall be set at the weighted class average retail rate for their respective service classification. The bill credit for CIEP eligible customers will be set at the average hourly energy price. Customers served by a third-party supplier will have their credit based upon the BGS rate. The subscriber's bill credit will be used to offset the subscriber's total bill up to the amount of actual metered consumption. The calculation of the value of the bill credit shall remain as described above and shall remain in effect for the life of the project, defined as no more than 20 years from the date of commercial operation of the project or the period until the project is decommissioned, whichever comes first, in addition to any modifications subsequently ordered by the BPU. The community solar bill credit will be specifically identified as the community solar bill credit in a separate line on the subscribers' utility bills.

Section 13 – Community Solar Energy Pilot Program

13.04 Community Solar Bill Credits (Continued)

An annualized period shall be established for each subscriber. The annualized period shall begin on the day a subscriber first earns a community solar bill credit based on the delivery of energy, and continues for a period of 12 months, until the subscription ends, or until the subscriber's Company account is closed, whichever occurs earlier. The Company may sync up the monthly billing period of subscribers and projects, by modifying, with due notice given, the monthly billing period for subscribers upon their first month of participation in the community solar project. Excess credits above the level of the metered monthly consumption shall carry over from monthly billing period to monthly billing period, with the balance of credits accumulating until the earlier of either the end of the annualized period, the closure of the subscriber's Company account, or the end of the subscriber's community solar subscription. At the end of the annualized period and/or when a subscriber's Company account is closed and/or at the end of the subscriber's community solar subscription, any excess net bill credits greater than the sum of all appropriate billable charges shall be compensated at the Company's average LMP of the JCP&L transmission zone. The excess compensation must be returned to the subscriber by bill credit, wire transfer, or check. If a subscriber receives net excess credits for each of the three previous consecutive years, the subscriber organization must resize the subscriber's subscription size to ensure it does not exceed 100 percent of historic annual usage, calculated over the past 12 months, available at the time of the reassessment.

Any generation delivered to the grid that has not been allocated to a subscriber may be "banked" by the project operator in a dedicated project Company account for an annualized period of up to 12 months. The banked credits may be distributed by the project operator to any new or existing subscriber during that 12-month period, in conformance with subscription requirements set forth in N.J.A.C. 14:8-9.6. At the end of the up to 12-month period, any remaining generation credits shall be compensated at the Company's average LMP of the JCP&L transmission zone. Subscribers must have an active electric account within the Company's service territory of the community solar project to which they are subscribed. Upon Company request, If required by the Company, subscribers must agree to a remote read smart meter upon EDC request, purchased and installed at EDC cost.

The Company will utilize a standardized process for sharing subscriber information between subscriber organizations and the Company by which subscriber organizations can submit the lists of subscribers. Subscriber organizations shall send to the Company a list of subscribers to the project with all appropriate subscriber information, no later than 60 days prior to the first monthly billing period for the community solar project. Additionally, subscriber organizations shall send an updated list to the Company once per month.

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Appendix A - Unit Costs of Underground Construction
Single Family Developments

Appendix A - Residential Electric Underground Extensions
The Applicant shall pay the Company the amount determined from the following table:

A. Base Charges

1. Single Family	Average Front Footage Per Lot <= 125 Ft	126-225 Ft	226-325 Ft	>= 326Ft
Nonrefundable charge per building lot				
• With Applicant providing all trenching and road crossing conduits	$ 581.00	$ 723.00	$ 864.00	$ 1,605.00
Refundable deposit based on equivalent overhead construction	$ 914.00	$1,828.00	$2,742.00	$ 4,570.00

2. Lots requiring 1Φ primary extension
   Without primary enclosure $1,847.38
   With primary enclosure $5,260.30

3. Duplex-family buildings, mobile homes, multiple occupancy buildings, three-phase high capacity extensions, lots requiring primary extensions thereon, excess transformer capacity above 8.5 KVA, etc. — Charge to be based on differential cost according to unit costs specified in Exhibits I through III

B. Additional Charges

1. Street Lights - SVL
   16 foot fiberglass pole with standard colonial post top luminaire ..... $ 492.00
   16 foot fiberglass pole with ornate colonial post top luminaire $1,199.00
   30 foot fiberglass pole with cobra head luminaire on 6 foot bracket $1,268.00
   12 foot 9 inch ornate fiberglass pole with ornate colonial post top luminaire $2,666.00
   12 foot 9 inch ornate fiberglass pole with acorn style post top luminaire - LED $3,098.00
   16 foot Fiberglass pole with colonial post top luminaire……$ 678.00
   30 foot fiberglass pole with Cobra Head……$1,247.00
   12 foot 9 inch ornate fiberglass pole with acorn style post top luminaire……..$2,145.00

2. Multi-Phase Construction $1.11 per added phase per foot

3. Pavement cutting and restoration, rock removal, blasting, difficult digging, and special backfill — At actual low bid cost with option of Applicant to contract for as limited by NJAC

Note: All charges are subject to taxes as provided in Section 3.14.

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JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 14 ELECTRIC - PART II Original Sheet No. 45

Appendix A - Exhibit I - Unit Costs of Underground Construction Single-Phase 15 kV

Item	Unit	Total Cost
1. Primary cable 1/0 aluminum	per foot	$ 4.04
2. Secondary cable 3/0 aluminum	per foot	3.29
350 MCM aluminum	per foot	5.63
500 MCM aluminum	per foot	7.17
750 MCM aluminum	per foot	10.33
3. Service - 200 amp and below	per foot	3.29
50 feet complete	each	596.84
4. Primary termination - branch	each	1,642.24
5. Primary junction enclosure - branch	each	3,412.92
6. Secondary enclosure	each	1,134.53
7. Conduit - 3 inch PVC	per foot	8.09
Conduit - 4 inch PVC	per foot	8.53
8. Street light cable - # 12 cu. duplex	per foot	3.02
9. Transformers - including fiberglass pad		
25 kVa – single-phase	each	3,291.68
50 kVa – single-phase	each	3,688.43
75 kVa – single-phase	each	4,865.17
100 kVa – single-phase	each	4,395.02
167 kVa – single-phase	each	5,552.27
25 kVa – single-phase Dual Voltage	each	3,169.99
50 kVa – single-phase Dual Voltage	each	3,397.93
75 kVa – single-phase Dual Voltage	each	5,437.36
10. Street light poles		
16 foot post top fiberglass pole	each	678.14
30 foot fiberglass pole	each	1,246.67
12 foot 9 inch ornate fiberglass pole	each	2,144.67
11. Street light luminaire – cobra head SVL	each	567.88
12. Post top luminaire – SVL		
50, 70, 100 & 150 watt colonial style	each	360.15
70 & 100 watt ornate colonial style	each	1,067.86
70 & 100 watt ornate acorn style	each	1,499.75
13. Primary splice – # 2 aluminum	each	223.97

Note: All charges are subject to taxes as provided in Section 3.14.

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JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 14 ELECTRIC - PART II Original Sheet No. 46

Appendix A - Exhibit II - Unit Costs of Underground Construction Three-Phase 15 kV

	Item	Unit	Total Cost
1.	Primary cable – three-phase main feeder	per foot	$ 22.24
2.	Secondary cable - 4-wire 350 MCM aluminum	per foot	9.53
3.	Service cable - 4-wire 350 MCM aluminum	per foot	10.75
4.	Primary termination - main		
	# 2 aluminum three-phase	each	4,226.12
	1000 MCM aluminum three-phase	each	5,682.50
5.	Primary junction - main	each	5,339.66
6.	Primary switch - main		
	PMH-9	each	31,712.74
	PMH-10	each	27,685.16
	PMH-11	each	28,702.93
	PMH-12	each	34,269.87
7.	Conduit - 5 inch PVC	per foot	13.75
	- 6 inch PVC	per foot	12.82
8.	Transformers - including concrete pad		
	75 kVa three-phase	each	7,872.26
	150 kVa three-phase	each	9,297.18
	300 kVa three-phase	each	15,199.18
	500 kVa three-phase	each	14,704.84
9.	Primary splice – 15 kV three-phase cable	each	432.37

Note: All charges are subject to taxes as provided in Section 3.14.

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JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 14 ELECTRIC - PART II Original Sheet No. 47

Appendix A - Exhibit III - Unit Costs of Overhead Construction Single and Three-Phase 15 kV

	Item	Unit	Total Cost
1.	Pole line (including 40 foot poles, anchors & guys)	per foot	$ 6.94*
2.	Primary wire		
	Single-phase – branch	per foot	2.93
	Three-phase – main	per foot	13.92
3.	Primary wire - neutral	per foot	2.74
4.	Secondary cable		
	Three-wire	per foot	5.48
	Four-wire	per foot	7.77
5.	Service		
	Single-phase	each	264.70
	Single–phase - 200 amp and below	per foot	2.72
	Three-phase – up to 200 amp	per foot	3.93
	Three-phase – over 200 amp	per foot	5.62
6.	Transformers		
	25 kVa – single-phase	each	1,776.44
	50 kVa – single-phase	each	2,269.32
	75 kVa – single-phase	each	2,860.31
	100 kVa – single-phase	each	3,312.11
	167 kVa – single-phase	each	3,327.65
	3- 25 kVa – three-phase	each	4,943.29
	3- 50 kVa – three-phase	each	6,391.93
	3- 75 kVa – three-phase	each	8,421.13
	3-100 kVa – three-phase	each	9,776.53
	3-167 kVa – three-phase	each	9,823.15
7.	Street light luminaire – cobra head SVL	each	546.61

Pole line cost to be used = $6.94 / 2 = $3.47

Note: All charges are subject to taxes as provided in Section 3.14.

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JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 14 ELECTRIC - PART II Original Sheet No. 48

Appendix A - Exhibit III - Unit Costs of Overhead Construction Single and Three-Phase 15 kV

Item	Unit	Total Cost
8. Street light luminaire – LED – Contributions		
Monthly Contribution Fixture charge of $2.65		
30 W Cobra Head	each	$ 358.38
50 W Cobra Head	each	354.88
90 W Cobra Head	each	403.55
130 W Cobra Head	each	492.97
260 W Cobra Head	each	694.22
50 W Acorn	each	1,295.80
90 W Acorn	each	1,243.30
50 W Colonial	each	619.38
90 W Colonial	each	793.88
Monthly Contribution Fixture charge of $4.24		
30 W Cobra Head	each	209.20
50 W Cobra Head	each	205.70
90 W Cobra Head	each	254.37
130 W Cobra Head	each	343.79
260 W Cobra Head	each	545.04
50 W Acorn	each	1,146.62
90 W Acorn	each	1,094.12
50 W Colonial	each	470.20
90 W Colonial	each	644.70

Note: All charges are subject to taxes as provided in Section 3.14.

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JERSEY CENTRAL POWER & LIGHT COMPANY

BPU NO. 14 ELECTRIC ORIGINAL TITLE SHEET

TARIFF for SERVICE

Part III

Service Classifications and Riders

Issued: **Effective:**

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300 Madison Avenue, Morristown, NJ 07962-1911

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 14 ELECTRIC - PART III Original Sheet No. 1

PART III
SERVICE CLASSIFICATIONS AND RIDERS
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300 Madison Avenue, Morristown, NJ 07962-1911

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 14 ELECTRIC - PART III Original Sheet No. 2

PART III
SERVICE CLASSIFICATIONS AND RIDERS
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Issued: **Effective:**

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300 Madison Avenue, Morristown, NJ 07962-1911

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 14 ELECTRIC - PART III Original Sheet No. 3

Service Classification RS
Residential Service

APPLICABLE TO USE OF SERVICE FOR: Service Classification RS is available for: (a) Individual Residential Structures; (b) separately metered residences in Multiple Residential Structures; (c) incidental use for non-residential purposes when included along with the residence; and/or (d) Auxiliary Residential Purposes whether metered separately from the residence or not.

This Service Classification is optional for customers which elect to be billed hereunder rather than under Service Classification RT. (Also see Part II, Section 2.03)

CHARACTER OF SERVICE: Single-phase service, with limited applications of three-phase service, at secondary voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)

2) **Transmission Charge: $0.010056** per KWH for all KWH including Water Heating

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge: $ 5.60** per month
Supplemental Customer Charge: $ 2.92 per month Off-Peak/Controlled Water Heating

2) **Distribution Charge:**

June through September:
$0.022169 per KWH for the first 600 KWH (except Water Heating)
$0.087667 per KWH for all KWH over 600 KWH (except Water Heating)

October through May:
$0.036315 per KWH for all KWH (except Water Heating)

Water Heating Service:
$0.024238 per KWH for all KWH for Off-Peak Water Heating
$0.031925 per KWH for all KWH for Controlled Water Heating

BPU No. 14 ELECTRIC - PART III **Original Sheet No. 4**

Service Classification RS
Residential Service

3) Non-utility Generation Charge (Rider NGC): (See Rider NGC for any applicable St. Lawrence Hydroelectric Power credit)
See Rider NGC for rate per KWH for all KWH including Off-Peak/Controlled Water Heating

4) Societal Benefits Charge (Rider SBC):
See Rider SBC for rate per KWH for all KWH including Off-Peak/Controlled Water Heating

5) RGGI Recovery Charge (Rider RRC):
See Rider RRC for rate per KWH for all KWH including Off-Peak/Controlled Water Heating

6) Zero Emission Certificate Recovery Charge (Rider ZEC):
See Rider ZEC for rate per KWH for all KWH including Off-Peak/Controlled Water Heating

7) Tax Act Adjustment (Rider TAA):
See Rider TAA for rate per KWH for all KWH including Off-Peak/Controlled Water Heating

8) JCP&L Reliability Plus Charge (Rider RP):
See Rider RP for rate per KWH for all KWH including Off-Peak/Controlled Water Heating

9) JCP&L Lost Revenue Adjustment Mechanism Charge (Rider LRAM):
See Rider LRAM for rate per KWH for all KWH including Off-Peak/Controlled Water Heating

10) Electric Vehicle Charger Rider (Rider EV):
See Rider EV for information about the EV Driven Program

TERM OF CONTRACT: None, except that reasonable notice of service discontinuance will be required. Where special circumstances apply or special or unusual facilities are supplied, a contract of one year or more may be required.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill.

SERVICE CHARGE: A Service Charge of **$14.00** shall be applicable for initiating service to a customer under any Service Classification (see Part II, Section 2.01). A **$54.00** Service Charge shall be applicable for final bill readings requested to be performed other than during the normal working hours of 8 AM to 4:30 PM, Monday through Friday. (See Part II, Section 3.13)

RECONNECTION CHARGES: A Reconnection Charge, applicable after a discontinuance requested by the customer or because of a default by the customer, of **$35.00** is applicable to service reconnections which can be performed at the meter. The charge for all reconnections which cannot be performed at the meter shall be based upon the costs incurred by the Company. (See Part II, Section 7.04)

DELINQUENT CHARGE: A Field Collection Charge of **$35.00** shall be applicable for each collection visit made to the customer's premises. (See Part II, Section 3.20)

Service Classification RS
Residential Service

SPECIAL PROVISIONS:

(a) Restricted Off-Peak Water Heating Service: Locations currently receiving service under this Special Provision which have automatic storage-type water heaters for the supply of hot water requirements of the premises, where such water heaters comply with and are installed in accordance with Company specifications, shall be billed a Supplemental Customer Charge, and shall have the KWH used during the off-peak hours of 8 PM to 8 AM Eastern Standard Time measured by a separate meter and billed at the Charges provided above. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change. (Also see Part II, Section 5.09)

(b) Restricted Controlled Water Heating Service: Locations currently receiving service under this Special Provision which have automatic storage-type water heaters for the supply of hot water requirements of the premises, where such water heaters comply with and are installed in accordance with Company specifications and have the operation of both upper and lower elements restricted by Company control devices to the hours of 11 PM to 4 PM Eastern Standard Time, shall be billed a Supplemental Customer Charge, and shall have the KWH used during those hours measured by a separate meter and billed at the Charges provided above. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change. (Also see Part II, Section 5.10)

ADDITIONAL MODIFYING RIDER: This Service Classification may also be modified for other Rider(s) subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

Service Classification RT
Residential Time-of-Day Service

APPLICABLE TO USE OF SERVICE FOR: Service Classification RT is available for: (a) Individual Residential Structures; (b) separately metered residences in Multiple Residential Structures; (c) incidental use for non-residential purposes when included along with the residence; and/or (d) Auxiliary Residential Purposes whether metered separately from the residence or not.

This Service Classification is optional for customers which elect to be billed hereunder rather than under Service Classification RS. (Also see Part II, Section 2.03)

CHARACTER OF SERVICE: Single-phase service, with limited applications of three-phase service, at secondary voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)

2) **Transmission Charge: $0.010056** per KWH for all KWH on-peak and off-peak

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge: $ 9.07** per month
Solar Water Heating Credit: $ 2.28 per month

2) **Distribution Charge:**
$0.067550 per KWH for all KWH on-peak for June through September
$0.049618 per KWH for all KWH on-peak for October through May
$0.031555 per KWH for all KWH off-peak

3) **Non-utility Generation Charge (Rider NGC): (See Rider NGC for any applicable St. Lawrence Hydroelectric Power credit)**
See Rider NGC for rate per KWH for all KWH on-peak and off-peak

4) **Societal Benefits Charge (Rider SBC):**
See Rider SBC for rate per KWH for all KWH on-peak and off-peak

5) **RGGI Recovery Charge (Rider RRC):**
See Rider RRC for rate per KWH for all KWH on-peak and off-peak

6) **Zero Emission Certificate Recovery Charge (Rider ZEC):**
See Rider ZEC for rate per KWH for all KWH on-peak and off-peak

7) **Tax Act Adjustment (Rider TAA):**
See Rider TAA for rate per KWH for all KWH on-peak and off-peak

8) **JCP&L Reliability Plus Charge (Rider RP):**
See Rider RP for rate per KWH for all KWH on-peak and off-peak

9) **JCP&L Lost Revenue Adjustment Mechanism Charge (Rider LRAM):**
See Rider LRAM for rate per KWH for all KWH on-peak and off-peak

10) **Electric Vehicle Charger Rider (Rider EV):**
See Rider EV for information about the EV Driven Program

Service Classification RT
Residential Time-of-Day Service

DEFINITION OF ON-PEAK AND OFF-PEAK HOURS: The hours to be considered as on-peak are from 8 AM to 8 PM Eastern Standard Time, Monday through Friday. All other hours including weekend hours will be considered off-peak. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change. The Company may also selectively stagger the on-peak hours up to one hour in either direction when required to alleviate local distribution system peaking within high density areas. The off-peak hours will not, however, be less than 12 hours daily.

TERM OF CONTRACT: None, except that reasonable notice of service discontinuance will be required. Where special circumstances apply or special or unusual facilities are supplied, contracts of one year or more may be required.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill.

SERVICE CHARGE: A Service Charge of **$14.00** shall be applicable for initiating service to a customer under any Service Classification (see Part II, Section 2.01). A **$54.00** Service Charge shall be applicable for final bill readings requested to be performed other than during the normal working hours of 8 AM to 4:30 PM, Monday through Friday. (See Part II, Section 3.13)

RECONNECTION CHARGES: A Reconnection Charge, applicable after a discontinuance requested by the customer or because of a default by the customer, of **$35.00** is applicable to service reconnections which can be performed at the meter. The charge for all reconnections which cannot be performed at the meter shall be based upon the costs incurred by the Company. (See Part II, Section 7.04)

DELINQUENT CHARGE: A Field Collection Charge of **$35.00** shall be applicable for each collection visit made to the customer's premises. (See Part II, Section 3.20)

SPECIAL PROVISION: Solar Water Heating Systems: For customers who install a solar water heating system with electric backup, the monthly Customer Charge shall be reduced by the credit provided above.

ADDITIONAL MODIFYING RIDER: This Service Classification may also be modified for other Rider(s), subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 14 ELECTRIC - PART III Original Sheet No. 8

Service Classification RGT
Residential Geothermal & Heat Pump Service

APPLICABLE TO USE OF SERVICE FOR: Service Classification RGT is available for residential customers residing in individual residential structures, or in separately metered residences in multiple-unit residential structures, who have one of the following types of electric space heating systems as the primary source of heat for such structure or unit and which system meets the corresponding energy efficiency criterion:

Geothermal Systems with Energy Efficiency Ratio (EER) of 13.0 or greater;
Heat Pump Systems with Seasonal Energy Efficiency Ratio (SEER) of 11.0 or greater, and a Heating Season Performance Factor (HSPF) which meets the then current Federal HSPF standards;
Room Unit Heat Pump Systems with Energy Efficiency Ratio (EER) of 9.5 or greater.

Service Classification RGT is not available for customers residing in individual residential structures, or in separately metered residences in multiple-unit residential structures, which have an electric resistance heating system as the primary source of space heating for such structure or unit.

CHARACTER OF SERVICE: Single-phase service, with limited applications of three-phase service, at secondary voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)

2) **Transmission Charge:**
$0.010056 per KWH for all KWH on-peak and off-peak for June through September
$0.010056 per KWH for all KWH for October through May

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge: $ 9.07** per month

2) **Distribution Charge:**

June through September:
$0.067550 per KWH for all KWH on-peak
$0.031555 per KWH for all KWH off-peak

October through May:
$0.036315 per KWH for all KWH

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Service Classification RGT
Residential Geothermal & Heat Pump Service

3) Non-utility Generation Charge (Rider NGC): (See Rider NGC for any applicable St. Lawrence Hydroelectric Power credit)
See Rider NGC per KWH for all KWH on-peak and off-peak

4) Societal Benefits Charge (Rider SBC):
See Rider SBC per KWH for all KWH on-peak and off-peak

5) RGGI Recovery Charge (Rider RRC):
See Rider RRC for rate per KWH for all KWH on-peak and off-peak

6) Zero Emission Certificate Recovery Charge (Rider ZEC):
See Rider ZEC for rate per KWH for all KWH on-peak and off-peak

7) Tax Act Adjustment (Rider TAA):
See Rider TAA for rate per KWH for all KWH on-peak and off-peak

8) JCP&L Reliability Plus Charge (Rider RP):
See Rider RP for rate per KWH for all KWH on-peak and off-peak

9) JCP&L Lost Revenue Adjustment Mechanism Charge (Rider LRAM):
See Rider LRAM for rate per KWH for all KWH on-peak and off-peak

10) Electric Vehicle Charger Rider (Rider EV):
See Rider EV for information about the EV Driven Program

DEFINITION OF ON-PEAK AND OFF-PEAK HOURS: The hours to be considered as on-peak are from 8 AM to 8 PM Eastern Standard Time, Monday through Friday. All other hours including weekend hours will be considered off-peak. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change. The Company may also selectively stagger the on-peak hours up to one hour in either direction when required to alleviate local distribution system peaking within high-density areas. The off-peak hours will not, however, be less than 12 hours daily.

TERM OF CONTRACT: None, except that reasonable notice of service discontinuance will be required. Where special circumstances apply or special or unusual facilities are supplied, contracts of one year or more may be required.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill.

SERVICE CHARGE: A Service Charge of **$14.00** shall be applicable for initiating service to a customer under any Service Classification (see Part II, Section 2.01). A **$54.00** Service Charge shall be applicable for final bill readings requested to be performed other than during the normal working hours of 8 AM to 4:30 PM, Monday through Friday. (See Part II, Section 3.13)

RECONNECTION CHARGES: A Reconnection Charge, applicable after a discontinuance requested by the customer or because of a default by the customer, of **$35.00** is applicable to service reconnections which can be performed at the meter. The charge for all reconnections which cannot be performed at the meter shall be based upon the costs incurred by the Company. (See Part II, Section 7.04)

DELINQUENT CHARGE: A Field Collection Charge of **$35.000** shall be applicable for each collection visit made to the customer's premises. (See Part II, Section 3.20)

ADDITIONAL MODIFYING RIDER: This Service Classification may also be modified for other Rider(s), subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

BPU No. 14 ELECTRIC - PART III **Original Sheet No. 10**

Service Classification GS
General Service Secondary

APPLICABLE TO USE OF SERVICE FOR: Service Classification GS is available for general service purposes at secondary voltages not included under Service Classifications RS, RT, RGT or GST.

CHARACTER OF SERVICE: Single or three-phase service at secondary voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly BGS-FP) **or Rider BGS-CIEP (Basic Generation Service – Commercial Industrial Energy Pricing)**

2) **Transmission Charge:**
$0.010056 per KWH for all KWH including Water Heating

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge:** **$ 5.31** per month single-phase
$19.08 per month three-phase

Supplemental Customer Charge: **$ 2.92** per month Off-Peak/Controlled Water Heating
$ 4.35 per month Day/Night Service
$19.82 per month Traffic Signal Service

2) **Distribution Charge:**

KW Charge: (Demand Charge)
$ 10.29 per maximum KW during June through September, in excess of 10 KW
$ 9.57 per maximum KW during October through May, in excess of 10 KW
$ 4.66 per KW Minimum Charge, in excess of 10 KW

Service Classification GS
General Service Secondary

KWH Charge:
June through September (excluding Water Heating and Traffic Signal Service):
$0.086167 per KWH for all KWH up to 1000 KWH
$0.006891 per KWH for all KWH over 1000 KWH

October through May (excluding Water Heating and Traffic Signal Service):
$0.079729 per KWH for all KWH up to 1000 KWH
$0.006891 per KWH for all KWH over 1000 KWH

Water Heating Service:
$0.024238 per KWH for all KWH Off-Peak Water Heating
$0.031925 per KWH for all KWH Controlled Water Heating

Traffic Signal Service:
$0.018057 per KWH for all KWH

Religious House of Worship Credit:
$0.043928 per KWH for all KWH up to 1000 KWH

3) **Non-utility Generation Charge (Rider NGC):**
See Rider NGC for rate per KWH for all KWH (including Off-Peak/Controlled Water Heating and Traffic Signal Service)

4) **Societal Benefits Charge (Rider SBC):**
See Rider SBC for rate per KWH for all KWH (including Off-Peak/Controlled Water Heating and Traffic Signal Service)

5) **CIEP – Standby Fee as provided in Rider CIEP – Standby Fee** (formerly Rider DSSAC)

6) **RGGI Recovery Charge (Rider RRC):**
See Rider RRC for rate per KWH for all KWH (including Off-Peak/Controlled Water Heating and Traffic Signal Service)

7) **Zero Emission Certificate Recovery Charge (Rider ZEC):**
See Rider ZEC for rate per KWH for all KWH (including Off-Peak/Controlled Water Heating and Traffic Signal Service)

8) **Tax Act Adjustment (Rider TAA):**
See Rider TAA for rate per KWH for all KWH (including Off-Peak/Controlled Water Heating and Traffic Signal Service)

9) **JCP&L Reliability Plus Charge (Rider RP):**
See Rider RP for rate per KWH for all KWH (including Off-Peak/Controlled Water Heating and traffic Signal Service)

10) **JCP&L Lost Revenue Adjustment Mechanism Charge (Rider LRAM):**
See Rider LRAM for rate per KWH for all KWH (including Off-Peak/Controlled Water Heating and traffic Signal Service)

11) **Electric Vehicle Charger Rider (Rider EV):**
See Rider EV for information about the EV Driven Program

MINIMUM DEMAND CHARGE PER MONTH: The monthly KW Demand Charge under Distribution Charge shall be the greater of (1) the product of the KW Charge per maximum KW provided above and the current month's maximum demand created during on-peak hours as determined below; or (2) the product of the KW Minimum Charge provided above and the highest on-peak or off-peak demand created in the current and preceding eleven months (but not less than the Contract Demand).

Service Classification GS
General Service Secondary

DETERMINATION OF DEMAND: The KW used for billing purposes shall be the maximum 15-minute integrated kilowatt demand during each billing month calculated to the nearest one-tenth KW. In instances where the Company has determined that the demand will not exceed 10 KW, and has therefore elected to not install a demand meter, the demand shall be considered less than 10 KW for billing purposes. Where Service is rendered under Special Provision (a), the on-peak demand shall be the maximum 15-minute integrated kilowatt demand created during the on-peak hours of 8 AM to 8 PM prevailing time, Monday through Friday each billing month, while the off-peak demand shall be the maximum demand created during the remaining hours. A Contract Demand not less than the actual monthly demands may also be specified for mutually agreeable contract purposes.

TERM OF CONTRACT: None, except that reasonable notice of service discontinuance will be required. Where special circumstances apply or special or unusual facilities are supplied by the Company, a contract of one year or more to supply such facilities or accommodate special circumstances may be required for any Full Service Customer and any Delivery Service Customer.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill. Overdue bills thereafter become subject to a late payment charge as described in Section 3.19, Part II.

SERVICE CHARGE: A Service Charge of **$14.00** shall be applicable for initiating service to a customer under any Service Classification (see Part II, Section 2.01). A **$54.00** Service Charge shall be applicable for final bill readings requested to be performed other than during the normal working hours of 8 AM to 4:30 PM, Monday through Friday. (See Part II, Section 3.13)

RECONNECTION CHARGES: A Reconnection Charge, applicable after a discontinuance requested by the customer or because of a default by the customer, of **$35.00** is applicable to service reconnections which can be performed at the meter. The charge for all reconnections which cannot be performed at the meter shall be based upon the costs incurred by the Company. (See Part II, Section 7.04)

DELINQUENT CHARGE: A Field Collection Charge of **$35.00** shall be applicable for each collection visit made to the customer's premises. (See Part II, Section 3.20)

RECONNECTIONS WITHIN 12-MONTH PERIOD: Customers who request a disconnection and reconnection of service at the same location within a 12-month period shall not be relieved of Minimum Demand Charges resulting from demands created during the preceding eleven months, even though occurring prior to such disconnection.

Customers who request more than one disconnection and reconnection of service at the same location within a 12-month period shall be subject to the conditions specified above for the first such period of disconnection. In addition, for subsequent periods of disconnection, the customer shall be required to pay an additional Reconnection Charge equivalent to the sum of the Minimum Demand Charges, determined in accordance with the conditions specified in the preceding paragraph, for each month of that subsequent period.

Service Classification GS
General Service Secondary

SPECIAL PROVISIONS:

(a) Day/Night Service: Customers who normally operate in such manner that their maximum demands do not occur during the Company's on-peak period and elect to receive Service under this Special Provision shall have their monthly demand charge under this Service Classification based upon the greater of: (a) the maximum on-peak demand created during the month; or (b) 40 percent of the maximum off-peak demand created during the month. For the monthly KW Minimum Charge calculation, the Customer's demand will be based on the greater of: (a) the maximum on-peak demand created during the current and preceding eleven months; or (b) 40 percent of the maximum off-peak demand created during the current and preceding eleven months (but not less than the Contract Demand). Customers served under this Special Provision shall be billed an additional Supplemental Customer Charge provided above.

(b) Restricted Commercial and Industrial Space Heating Service: Customers served as of February 6, 1979, who have (1) electricity as the sole primary source of energy for space heating the entire structure(s) as well as for lighting, power, cooking, refrigeration, water heating, and similar purposes except for incidental special applications or purposes where electrical energy cannot reasonably be used; (2) the sum of the connected loads for lighting, space heating, cooking, and water heating exceed 50% of the total connected load; and (3) at least 50% of the total electrical load is located in a structure(s) heated by electricity; shall have the monthly KW Minimum Charge calculation modified such that the Customer's demand will be based on the highest demand established in the summer billing months only.

(c) Traffic Signal Service: Customers receiving service for traffic signal installations shall be billed an additional monthly Supplemental Customer Charge and the KWH Charges provided above.

(d) Restricted Off-Peak Water Heating Service: Locations currently receiving Service under this Special Provision which have automatic storage-type water heaters for the supply of hot water requirements of the premises, where such water heaters comply with and are installed in accordance with Company specifications, shall be billed a Supplemental Customer Charge, and shall have the KWH used during the off-peak hours of 8 PM to 8 AM Eastern Standard Time measured by a separate meter and billed at the Charges provided above. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change. (Also see Part II, Section 5.09)

(e) Restricted Controlled Water Heating Service: Locations currently receiving Service under this Special Provision which have automatic storage-type water heaters for the supply of hot water requirements of the premises, where such water heaters comply with and are installed in accordance with Company specifications and have the operation of both upper and lower elements restricted by Company control devices to the hours of 11 PM to 4 PM Eastern Standard Time, shall be billed a Supplemental Customer Charge, and shall have the KWH used during those hours measured by a separate meter and billed at the Charges provided above. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change. (Also see Part II, Section 5.10)

(f) Religious Houses of Worship Service: When electric service is supplied to a customer where the primary use of service is for public religious services and the customer applies for and is eligible for such Service, the customer's monthly Distribution Charge will be subject to a KWH Credit provided above for the first 1000 KWH usage per month. The Customer will be required to sign an Application for Religious Houses of Worship Service certifying eligibility. Upon request by Company, the Customer shall furnish satisfactory proof of eligibility for Service under this Special Provision.

ADDITIONAL MODIFYING RIDERS: This Service Classification may also be modified for other Rider(s), subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

Service Classification GS
General Service Secondary

VETERANS' ORGANIZATION SERVICE SPECIAL PROVISION:

Pursuant to N.J.S.A 48:2-21.41, when electric service is delivered to a customer that is a Veterans' Organization, 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 of 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.

The customer will continue to be billed on this Service Classification. At least once annually, the Company shall review eligible customers' delivery service charges under this Special Provision for all relevant periods. If the comparable delivery service charges under Service Classification RS (Residential Service) are lower than the delivery service charges under this Service Classification, a credit in the amount of the difference will be applied to the customer's next bill.

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Service Classification GST
General Service Secondary Time-Of-Day

APPLICABLE TO USE OF SERVICE FOR: Service Classification GST is available for general Service purposes for commercial and industrial customers establishing demands in excess of 750 KW in two consecutive months during the current 24-month period. Customers which were served under this Service Classification as part of its previous experimental implementation may continue such Service until voluntarily transferring to Service Classification GS.

CHARACTER OF SERVICE: Single or three-phase service at secondary voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP) **or Rider BGS-CIEP (Basic Generation Service – Commercial Industrial Energy Pricing)**

2) **Transmission Charge: $0.010056** per KWH for all KWH on-peak and off-peak

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge:** **$ 46.18** per month single-phase
$ 65.88 per month three-phase

2) **Distribution Charge:**

KW Charge: (Demand Charge)
$ 11.46 per maximum KW during June through September
$ 10.72 per maximum KW during October through May
$ 5.00 per KW Minimum Charge

KWH Charge:
$0.005165 per KWH for all KWH on-peak
$0.005165 per KWH for all KWH off-peak

Service Classification GST
General Service Secondary Time-Of-Day

3) **Non-utility Generation Charge (Rider NGC):**
See Rider NGC for rate per KWH for all KWH on-peak and off-peak

4) **Societal Benefits Charge (Rider SBC)**:
See Rider SBC for rate per KWH for all KWH on-peak and off-peak

5) **CIEP – Standby Fee as provided in Rider CIEP – Standby Fee** (formerly Rider DSSAC)

6) **RGGI Recovery Charge (Rider RRC):**
See Rider RRC for rate per KWH for all KWH on-peak and off-peak

7) **Zero Emission Certificate Recovery Charge (Rider ZEC):**
See Rider ZEC for rate per KWH for all KWH on-peak and off-peak

8) **Tax Act Adjustment (Rider TAA):**
See Rider TAA for rate per KWH for all KWH on-peak and off-peak

9) **JCP&L Reliability Plus Charge (Rider RP):**
See Rider RP for rate per KW for all KW

10) **JCP&L Lost Revenue Adjustment Mechanism Charge (Rider LRAM):**
See Rider LRAM for rate per KW for all KW

11) **Electric Vehicle Charger Rider (Rider EV):**
See Rider EV for information about the EV Driven Program

MINIMUM DEMAND CHARGE PER MONTH: The monthly KW Demand Charge under Distribution Charge shall be the greater of (1) the product of the KW Charge per maximum KW provided above and the current month's maximum demand created during on-peak hours as determined below; or (2) the product of the KW Minimum Charge provided above and the highest on-peak or off-peak demand created in the current and preceding eleven months (but not less than the Contract Demand).

DETERMINATION OF DEMAND: The KW during on-peak hours used for billing purposes shall be the maximum 15-minute integrated kilowatt demand created during the on-peak hours each billing month calculated to nearest one-tenth KW. The off-peak demand shall be the maximum demand created during the remaining hours. A Contract Demand not less than the actual monthly demands may also be specified for mutually agreeable contract purposes.

DEFINITION OF ON-PEAK AND OFF-PEAK HOURS: The hours to be considered as on-peak are from 8 AM to 8 PM prevailing time Monday through Friday. All other hours including weekend hours will be considered off-peak. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change. The off-peak hours will not be less than 12 hours daily.

TERM OF CONTRACT: None, except that reasonable notice of service discontinuance will be required. Where special circumstances apply or special or unusual facilities are supplied by the Company, a contract of one year or more to supply such facilities or accommodate special circumstances may be required for any Full Service Customer and any Delivery Service Customer.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill. Overdue bills thereafter become subject to a late payment charge as described in Section 3.19, Part II.

SERVICE CHARGE: A Service Charge of **$14.00** shall be applicable for initiating service to a customer under any Service Classification (see Part II, Section 2.01). A **$54.00** Service Charge shall be applicable for final bill readings requested to be performed other than during the normal working hours of 8 AM to 4:30 PM, Monday through Friday. (See Part II, Section 3.13)

Service Classification GST
General Service Secondary Time-Of-Day

RECONNECTION CHARGES: A Reconnection Charge, applicable after a discontinuance requested by the customer or because of a default by the customer, of **$35.00** is applicable to service reconnections which can be performed at the meter. The charge for all reconnections which cannot be performed at the meter shall be based upon the costs incurred by the Company. (See Part II, Section 7.04)

RECONNECTIONS WITHIN 12-MONTH PERIOD: Customers who request a disconnection and reconnection of service at the same location within a 12-month period shall not be relieved of Minimum Demand Charges resulting from demands created during the preceding eleven months, even though occurring prior to such disconnection.

Customers who request more than one disconnection and reconnection of service at the same location within a 12-month period shall be subject to the conditions specified above for the first such period of disconnection. In addition, for subsequent periods of disconnection, the customer shall be required to pay an additional Reconnection Charge equivalent to the sum of the Minimum Demand Charges, determined in accordance with the conditions specified in the preceding paragraph, for each month of that subsequent period.

DELINQUENT CHARGE: A Field Collection Charge of **$35.00** shall be applicable for each collection visit made to the customer's premises. (See Part II, Section 3.20)

ADDITIONAL MODIFYING RIDERS: This Service Classification may also be modified for other Rider(s), subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

Service Classification GST
General Service Secondary Time-Of-Day

VETERANS' ORGANIZATION SERVICE SPECIAL PROVISION:

Pursuant to N.J.S.A 48:2-21.41, when electric service is delivered to a customer that is a Veterans' Organization, 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 of 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.

The customer will continue to be billed on this Service Classification. At least once annually, the Company shall review eligible customers' delivery service charges under this Special Provision for all relevant periods. If the comparable delivery service charges under Service Classification RS (Residential Service) are lower than the delivery service charges under this Service Classification, a credit in the amount of the difference will be applied to the customer's next bill.

Service Classification GP
General Service Primary

APPLICABLE TO USE OF SERVICE FOR: Service Classification GP is available for general service purposes for commercial and industrial customers.

CHARACTER OF SERVICE: Single or three-phase service at primary voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy, Capacity and Reconciliation Charges as provided in Rider BGS-CIEP (Basic Generation Service – Commercial Industrial Energy Pricing).**
2) **Transmission Charge: $0.006116** per KWH for all KWH

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge: $ 80.09** per month
2) **Distribution Charge:**

   KW Charge: (Demand Charge)
   $ 8.84 per maximum KW during June through September
   $ 8.20 per maximum KW during October through May
   $ 2.99 per KW Minimum Charge

   KVAR Charge: (Kilovolt-Ampere Reactive Charge)
   $ 0.58 per KVAR based upon the 15-minute integrated KVAR demand which occurs coincident with the maximum on-peak KW demand in the current billing month (See Part II, Section 5.05)

   KWH Charge:
   $0.003681 per KWH for all KWH on-peak and off-peak
3) **Non-utility Generation Charge (Rider NGC):**
   See Rider NGC for rate per KWH for all KWH on-peak and off-peak
4) **Societal Benefits Charge (Rider SBC)**:
   See Rider SBC for rate per KWH for all KWH on-peak and off-peak
5) **CIEP – Standby Fee as provided in Rider CIEP – Standby Fee** (formerly Rider DSSAC)
6) **RGGI Recovery Charge (Rider RRC):**
   See Rider RRC for rate per KWH for all KWH on-peak and off-peak
7) **Zero Emission Certificate Recovery Charge (Rider ZEC):**
   See Rider ZEC for rate per KWH for all KWH on-peak and off-peak
8) **Tax Act Adjustment (Rider TAA):**
   See Rider TAA for rate per KWH for all KWH on-peak and off-peak
9) **JCP&L Reliability Plus Charge (Rider RP):**
   See Rider RP for rate per KW for all KW
10) **JCP&L Lost Revenue Adjustment Mechanism Charge (Rider LRAM):**
    See Rider LRAM for rate per KW for all KW
11) **Electric Vehicle Charger Rider (Rider EV):**
    See Rider EV for information about the EV Driven Program

Service Classification GP
General Service Primary

MINIMUM DEMAND CHARGE PER MONTH: The monthly KW Demand Charge under Distribution Charge shall be the greater of (1) the product of the KW Charge per maximum KW provided above and the current month's maximum demand created during on-peak hours as determined below; or (2) the product of the KW Minimum Charge provided above and the highest on-peak or off-peak demand created in the current and preceding eleven months (but not less than the Contract Demand).

DETERMINATION OF DEMAND: The KW during on-peak hours used for billing purposes shall be the maximum 15-minute integrated kilowatt demand created during the on-peak hours each billing month calculated to nearest one-tenth KW. The off-peak demand shall be the maximum demand created during the remaining hours. A Contract Demand not less than the actual monthly demands may also be specified for mutually agreeable contract purposes.

DEFINITION OF ON-PEAK AND OFF-PEAK HOURS: The hours to be considered as on-peak are from 8 a.m. to 8 p.m. prevailing time Monday through Friday. All other hours including weekend hours will be considered off-peak. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change. The off-peak hours will not be less than 12 hours daily.

TERM OF CONTRACT: None, except that reasonable notice of service discontinuance will be required. Where special circumstances apply or special or unusual facilities are supplied by the Company, a contract of one year or more to supply such facilities or accommodate special circumstances may be required for any Full Service Customer and any Delivery Service Customer.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill. Overdue bills thereafter become subject to a late payment charge as described in Section 3.19, Part II.

SERVICE CHARGE: A Service Charge of **$14.00** shall be applicable for initiating service to a customer under any Service Classification (see Part II, Section 2.01). A **$54.00** Service Charge shall be applicable for final bill readings requested to be performed other than during the normal working hours of 8 AM to 4:30 PM, Monday through Friday. (See Part II, Section 3.13)

DISCONNECTION / RECONNECTION CHARGES: Charges for all disconnections and reconnections shall be based upon actual costs. (See Part II, Section 7.04)

RECONNECTIONS WITHIN 12-MONTH PERIOD: Customers who request a disconnection and reconnection of service at the same location within a 12-month period shall not be relieved of Minimum Demand Charges resulting from demands created during the preceding eleven months, even though occurring prior to such disconnection.

Customers who request more than one disconnection and reconnection of service at the same location within a 12-month period shall be subject to the conditions specified above for the first such period of disconnection. In addition, for subsequent periods of disconnection, the customer shall be required to pay an additional Reconnection Charge equivalent to the sum of the Minimum Demand Charges, determined in accordance with the conditions specified in the preceding paragraph, for each month of that subsequent period.

ADDITIONAL MODIFYING RIDERS: This Service Classification may also be modified for other Rider(s), subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

Service Classification GP
General Service Primary

VETERANS' ORGANIZATION SERVICE SPECIAL PROVISION:

Pursuant to N.J.S.A 48:2-21.41, when electric service is delivered to a customer that is a Veterans' Organization, 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 of 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.

The customer will continue to be billed on this Service Classification. At least once annually, the Company shall review eligible customers' delivery service charges under this Special Provision for all relevant periods. If the comparable delivery service charges under Service Classification RS (Residential Service) are lower than the delivery service charges under this Service Classification, a credit in the amount of the difference will be applied to the customer's next bill.

Service Classification GT
General Service Transmission

APPLICABLE TO USE OF SERVICE FOR: Service Classification GT is available for general service purposes for commercial and industrial customers.

CHARACTER OF SERVICE: Three-phase service at transmission voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy, Capacity and Reconciliation Charges as provided in Rider BGS-CIEP (Basic Generation Service – Commercial Industrial Energy Pricing).**

2) **Transmission Charge:** **$0.005376** per KWH for all KWH
$0.001448 per KWH for all KWH High Tension Service

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge: $ 343.97** per month

2) **Distribution Charge:**

KW Charge: (Demand Charge)
$ 5.67 per maximum KW
$ 1.51 per KW High Tension Service Credit
$ 3.77 per KW DOD Service Credit

KW Minimum Charge: (Demand Charge)
$ 1.72 per KW Minimum Charge
$ 1.13 per KW DOD Service Credit
$ 0.71 per KW Minimum Charge Credit

KVAR Charge: (Kilovolt-Ampere Reactive Charge)
$ 0.55 per KVAR based upon the 15-minute integrated KVAR demand which occurs coincident with the maximum on-peak KW demand in the current billing month (See Part II, Section 5.05)

KWH Charge:
$0.002850 per KWH for all KWH on-peak and off-peak
$0.001012 per KWH High Tension Service Credit
$0.001852 per KWH DOD Service Credit

3) **Non-utility Generation Charge (Rider NGC):**
See Rider NGC for rate per KWH for all KWH on-peak and off-peak – excluding High Tension Service
See Rider NGC for rate per KWH for all KWH on-peak and off-peak – High Tension Service

4) **Societal Benefits Charge (Rider SBC)**:
See Rider SBC for rate per KWH for all KWH on-peak and off-peak

Service Classification GT
General Service Transmission

5) **CIEP – Standby Fee as provided in Rider CIEP – Standby Fee** (formerly Rider DSSAC)
6) **RGGI Recovery Charge (Rider RRC):**
   See Rider RRC for rate per KWH for all KWH on-peak and off-peak
7) **Zero Emission Certificate Recovery Charge (Rider ZEC):**
   See Rider ZEC for rate per KWH for all KWH on-peak and off-peak
8) **Tax Act Adjustment (Rider TAA):**
   See Rider TAA for rate per KWH for all KWH on-peak and off-peak
9) **JCP&L Reliability Plus Charge (Rider RP):**
   See Rider RP for rate per KW for all KW
10) **JCP&L Lost Revenue Adjustment Mechanism Charge (Rider LRAM):**
   See Rider LRAM for rate per KW for all KW
11) **Electric Vehicle Charger Rider (Rider EV):**
   See Rider EV for information about the EV Driven Program

MINIMUM CHARGE PER MONTH: The monthly KW Charge (Demand Charge) under Distribution Charge shall be the greater of (1) the product of the KW Charge per maximum KW provided above and the current month's maximum demand created during on-peak hours as determined below; or (2) the product of the KW Minimum Charge provided above and the highest on-peak or off-peak demand created in the current and preceding eleven months (but not less than the Contract Demand). When the maximum on-peak demand created in the current and preceding eleven months has not exceeded 3% of the maximum off-peak demand created in the current and preceding eleven months, the KW Minimum Charge specified above shall be reduced by the KW Minimum Charge Credit stated above.

DETERMINATION OF DEMAND: The KW during on-peak hours used for billing purposes shall be the maximum 15-minute integrated kilowatt demand created during the on-peak hours each billing month calculated to nearest one-tenth KW. The off-peak demand shall be the maximum demand created during the remaining hours. A Contract Demand not less than the actual monthly demands may also be specified for mutually agreeable contract purposes.

DEFINITION OF ON-PEAK AND OFF-PEAK HOURS: The hours to be considered as on-peak are from 8 AM to 8 PM prevailing time Monday through Friday. All other hours including weekend hours will be considered off-peak. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change. The off-peak hours will not be less than 12 hours daily.

TERM OF CONTRACT: None, except that reasonable notice of service discontinuance will be required. Where special circumstances apply or special or unusual facilities are supplied by the Company, a contract of one year or more to supply such facilities or accommodate special circumstances may be required for any Full Service Customer and any Delivery Service Customer.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill. Overdue bills thereafter become subject to a late payment charge as described in Section 3.19, Part II.

SERVICE CHARGE: A Service Charge of **$14.00** shall be applicable for initiating service to a customer under any Service Classification (see Part II, Section 2.01). A **$54.00** Service Charge shall be applicable for final bill readings requested to be performed other than during the normal working hours of 8 AM to 4:30 PM, Monday through Friday. (See Part II, Section 3.13)

DISCONNECTION / RECONNECTION CHARGES: Charges for all disconnections and reconnections shall be based upon actual costs. (See Part II, Section 7.04)

RECONNECTIONS WITHIN 12-MONTH PERIOD: Customers who request a disconnection and reconnection of service at the same location within a 12-month period shall not be relieved of Minimum Demand Charges resulting from demands created during the preceding eleven months, even though occurring prior to such disconnection.

JERSEY CENTRAL POWER & LIGHT COMPANY

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Service Classification GT
General Service Transmission

RECONNECTIONS WITHIN 12-MONTH PERIOD: (Continued)
Customers who request more than one disconnection and reconnection of service at the same location within a 12-month period shall be subject to the conditions specified above for the first such period of disconnection. In addition, for subsequent periods of disconnection, the customer shall be required to pay an additional Reconnection Charge equivalent to the sum of the Minimum Demand Charges, determined in accordance with the conditions specified in the preceding paragraph, for each month of that subsequent period.

SPECIAL PROVISIONS:

(a) Commuter Rail Service: Where service is supplied to traction power accounts for a commuter rail system, such accounts shall be conjunctively billed based upon coincident demands. This Special Provision also modifies the DEFINITION OF ON-PEAK AND OFF-PEAK HOURS for Demand Charge purposes only, such that the following Federal Holidays are considered off-peak the entire day: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day and Christmas Day. In addition, the periods from 8 AM to 10 AM and from 5 PM to 8 PM prevailing time Monday through Friday shall be considered as off-peak for Demand Charge purposes only. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change.

Where traction power is supplied at high tension (230 KV) and such power is being provided during a limited period to supplant power normally supplied by another utility, that limited period shall be excluded for the purpose of determining billing demand.

(b) High Tension Service: Where service is supplied at 230 KV, the determination of KW and KVAR demands shall be modified to refer to 60-minute demands, and the Distribution KW and KWH Charges, except for KW Minimum Charge, shall be reduced by the High Tension Service Credits provided above to reflect the reduced line losses associated with service at this voltage level. Any Customer taking this Special Provision shall not be qualified for Special Provisions (c) and (d) below.

(c) Department of Defense Service: Where service is supplied to the major military installations of the United States Department of Defense at transmission voltages, the Distribution KW Charge, KW Minimum Charge and KWH Charge shall be reduced by the DOD Service Credits provided above.

(d) Closing of GTX Service: Upon the closing of Service Classification GTX effective April 1, 2004, for any GTX customer as of August 1, 2003 where service is supplied at 230 KV, the monthly billing demand shall be the maximum 60-minute integrated kilowatt demand created during all on-peak and off-peak hours of the billing month and the Distribution KW Charge (Demand Charge) shall be $0.54 per KW ($0.58 per KW including SUT). The Distribution KW Minimum Charge, KVAR Charge and KWH Charge provided above shall not apply, and the Non-utility Generation Charge shall be the lesser of (1) $0.000312 per KWH ($0.000333 per KWH including SUT), or (2) the net of NGC – High Tension Service stated above and an NGC Credit of $0.009844 per KWH ($0.010496 per KWH including SUT), but not less than zero, for all KWH usage. Effective May 1, 2018 and for an initial term of 10 years, the Societal Benefits Charge (Rider SBC) shall include only the Demand Side Factor (Rider DSF) charge.

ADDITIONAL MODIFYING RIDERS: This Service Classification may also be modified for other Rider(s), subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

Issued: **Effective:**

Filed pursuant to Order of Board of Public Utilities
Docket No. dated

Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

Service Classification GT
General Service Transmission

VETERANS' ORGANIZATION SERVICE SPECIAL PROVISION:

Pursuant to N.J.S.A 48:2-21.41, when electric service is delivered to a customer that is a Veterans' Organization, 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 of 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.

The customer will continue to be billed on this Service Classification. At least once annually, the Company shall review eligible customers' delivery service charges under this Special Provision for all relevant periods. If the comparable delivery service charges under Service Classification RS (Residential Service) are lower than the delivery service charges under this Service Classification, a credit in the amount of the difference will be applied to the customer's next bill.

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Service Classification OL
Outdoor Lighting Service

RESTRICTION: Mercury vapor (MV) area lighting is no longer available for replacement and shall be removed from service when existing MV area lighting fails.

APPLICABLE TO USE OF SERVICE FOR: Service Classification OL is available for outdoor flood and area lighting service operating on a standard illumination schedule of 4200 hours per year, and installed on existing wood distribution poles where secondary facilities exist. This Service is not available for the lighting of public streets and highways. This Service is also not available where, in the Company's judgment, it may be objectionable to others, or where, having been installed, it is objectionable to others.

CHARACTER OF SERVICE: Sodium vapor (SV) flood lighting, high pressure sodium (HPS) and mercury vapor (MV) area lighting for limited period (dusk to dawn) at nominal 120 volts.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):

(A) FIXTURE CHARGE:

Nominal Ratings

Lamp Wattage	Lamp & Ballast Wattage	Billing Month KWH *	HPS Area Lighting	MV Area Lighting	SV Flood Lighting
100	121	42	Not Available	**$3.06**	Not Available
175	211	74	Not Available	**$3.06**	Not Available
70	99	35	**$12.70**	Not Available	Not Available
100	137	48	**$12.70**	Not Available	Not Available
150	176	62	Not Available	Not Available	**$14.92**
250	293	103	Not Available	Not Available	**$15.67**
400	498	174	Not Available	Not Available	**$16.09**

* Based on standard illumination schedule of 4200 hours per year. Billing Month KWH is calculated to the nearest whole KWH based on the nominal lamp & ballast wattage of the light, times the light's annual burning hours per year, divided by 12 months per year, divided by 1000 watts per KWH.

(B) KWH CHARGES: The following charges apply to all Billing Month KWH and to all billing months (January through December). All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)
2) **Transmission Charge: $0.000000** per KWH

DELIVERY SERVICE (Distribution Charge includes Corporation Business Tax as provided in Rider CBT):

1) **Distribution Charge: $0.057275** per KWH
2) **Non-utility Generation Charge (Rider NGC): See Rider NGC for rate** per KWH
3) **Societal Benefits Charge (Rider SBC): See Rider SBC for rate** per KWH
4) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
5) **Zero Emission Certificate Recovery Charge (Rider ZEC): See Rider ZEC for rate** per KWH
6) **Tax Act Adjustment (Rider TAA): See Rider TAA for rate** per KWH
7) **JCP&L Reliability Plus Charge (Rider RP): See Rider RP for rate** per Fixture
8) **JCP&L Lost Revenue Adjustment Mechanism Charge (Rider LRAM): See Rider LRAM for rate** per KWH

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Service Classification OL
Outdoor Lighting Service

TERM OF CONTRACT: One year for each installation and thereafter on a monthly basis. Service which is terminated before the end of the contract term shall be billed the total of 1) the light's monthly Fixture Charge plus 2) the per KWH Distribution Charge applicable to the light's Billing Month KWH, plus 3) any additional monthly facility charges, times the remaining months of the contract term. Restoration of Service to lamps before the end of the contract term shall be made at the expense of the customer. Restoration of Service to lamps which have been disconnected after the contract term has expired shall require a 5 year contract term to be initialized.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill.

FACILITIES:

(a) Location of Facilities: Fixtures, lamps, controls, poles, hardware, conductors, and other appurtenances necessary for Service under this Service Classification shall be owned and maintained by the Company and must be located where they can be maintained by the use of the Company's standard mechanized equipment. Should customer desire that Company relocate its outdoor lighting facilities at any time, the relocation expense shall be paid by the customer.

(b) Additional Facilities: The per Billing Month charges for poles, transformers and spans of wire furnished by the Company for Service under this Service Classification prior to February 6, 1979 shall respectively be **$0.83, $3.36** and **$0.78** until such time as there is a customer change or those facilities are no longer utilized exclusively for service under this Service Classification, or if those facilities require replacement. New or replacement facilities furnished after that date shall be provided, at the Company's option under a 5-year term of contract, based upon payment of: (1) the following per Billing Monthly charges to be added to the Flat Service Charge: 35 foot pole: **$7.66**; 40 foot pole: **$8.57** Secondary Span: **$3.87;** or (2) a single non-refundable contribution determined under Appendix A (See Tariff Part II) charges when applicable; or otherwise (3) upon payment of specific charges determined under billing work order unitized costs.

(c) Maintenance of Facilities: Maintenance of facilities furnished by the Company under this Service Classification shall be scheduled during the Company's regular business hours upon notification by the customer of the need for such service. Maintenance of facilities at times other than during the Company's regular business hours shall be performed at the expense of the customer.

SPECIAL PROVISIONS:

(a) Seasonal Service: Such Service will be rendered when the cost of disconnection and reconnection is paid by the customer. During such months of disconnection, the Billing Month KWH for the light will be zero, such that the per KWH charges for BGS Energy and Reconciliation Charges, Transmission Charge, Non-utility Generation Charge, Societal Benefits Charge, RGGI Recovery Charge, Zero Emission Certificate Recovery Charge, Tax Act Adjustment and JCP&L Lost Revenue Adjustment Mechanism Charge will not be billed. The monthly Fixture Charge, the JCP&L Reliability Plus Charge and a seasonal Distribution Charge will be billed during such months of disconnection. The seasonal Distribution Charge will be equal to the Billing Month KWH for the light on a standard illumination schedule, times the per KWH Distribution Charge.

ADDITIONAL MODIFYING RIDER: This Service Classification may also be modified for other Rider(s) subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

Service Classification SVL
Sodium Vapor Street Lighting Service

RESTRICTION: Service Classification SVL is in the process of being eliminated and is withdrawn as a Tariff service offering except for the SVL installations of Customers already receiving Service hereunder on January 1, 2024, and only for the specific premises and class of service of such Customer served hereunder on such date. Further, the Company shall cease installation of Sodium Vapor Luminaries on the earliest to occur of January 1, 2026 or on such date as the Company is unable to purchase Sodium Vapor Luminaries in reasonable quantities and at reasonable prices as reasonably determined by the Company.

APPLICABLE TO USE OF SERVICE FOR: Service Classification SVL is available for series and multiple circuit street lighting Service operating on a standard illumination schedule of 4200 hours per year supplied from overhead or underground facilities on streets and roads (and parking areas at the option of the Company) where required by City, Town, County, State or other Municipal or Public Agency or by an incorporated association of local residents.

Sodium vapor conversions of mercury vapor or incandescent street lights shall be scheduled in accordance with the Company's SVL Conversion Program, and may be limited to no more than 5% of the lamps served under this Service Classification at the end of the previous year.

CHARACTER OF SERVICE: Sodium vapor lighting for limited period (dusk to dawn) at secondary voltage.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):

(A) FIXTURE CHARGE:

Nominal Ratings

Lamp Wattage	Lamp & Ballast Wattage	Billing Month KWH *	Company Fixture	Contribution Fixture	Customer Fixture
50	60	21	**$ 7.41**	**$ 2.09**	**$ 1.01**
70	85	30	**$ 7.41**	**$ 2.09**	**$ 1.01**
100	121	42	**$ 7.41**	**$ 2.09**	**$ 1.01**
150	176	62	**$ 7.41**	**$ 2.09**	**$ 1.01**
250	293	103	**$ 8.76**	**$ 2.09**	**$ 1.01**
400	498	174	**$ 8.76**	**$ 2.09**	**$ 1.01**

* Based on standard illumination schedule of 4200 hours per year. Billing Month KWH is calculated to the nearest whole KWH based on the nominal lamp & ballast wattage of the light, times the light's annual burning hours per year, divided by 12 months per year, divided by 1000 watts per KWH.

(B) KWH CHARGES: The following charges apply to all Billing Month KWH and to all billing months (January through December). All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)
2) **Transmission Charge: $0.000000** per KWH

DELIVERY SERVICE (Distribution Charge includes Corporation Business Tax as provided in Rider CBT):

1) **Distribution Charge: $0.057275** per KWH
2) **Non-utility Generation Charge (Rider NGC): See Rider NGC for rate** per KWH
3) **Societal Benefits Charge (Rider SBC): See Rider SBC for rate** per KWH
4) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
5) **Zero Emission Certificate Recovery Charge (Rider ZEC): See Rider ZEC for rate** per KWH
6) **Tax Act Adjustment (Rider TAA): See Rider TAA for rate** per KWH
7) **JCP&L Reliability Plus Charge (Rider RP): See Rider RP for rate** per Fixture
8) **JCP&L Lost Revenue Adjustment Mechanism Charge (Rider LRAM): See Rider LRAM for rate** per KWH

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Service Classification SVL
Sodium Vapor Street Lighting Service

TERM OF CONTRACT: Five years for each Company Fixture installation and thereafter on a monthly basis. Where special circumstances apply or special or unusual facilities are supplied, contracts of more than five years may be required. Service which is terminated by a Customer before the end of the contract term (and prior to the earliest to occur of January 1, 2026 or on such date as the Company is unable to purchase Sodium Vapor Luminaries in reasonable quantities and at reasonable prices as reasonably determined by the Company) shall be billed the total of 1) the light's monthly Fixture Charge plus 2) the per KWH Distribution Charge applicable to the light's Billing Month KWH, times the remaining months of the contract term. Restoration of Service to lamps before the end of the contract term shall be made at the expense of the customer.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill. Overdue bills thereafter become subject to a late payment charge as described in Section 3.19, Part II.

FACILITIES:

(a) Company Fixtures: Company Fixtures refer to all street lighting equipment including brackets and luminaires installed by the Company at its expense in accordance with its standard specifications, and all other equipment necessary in rendering the required Service installed on wood distribution poles or Street Light Poles. Company Fixtures shall be owned, operated, maintained and serviced by the Company.

(b) Contribution Fixtures: Contribution Fixtures refer to Company Fixtures for which installation the customer has paid the following Contributed Installation Cost. Contribution Fixtures shall be owned, operated, maintained and serviced by the Company.

> **Contributed Installation Cost:** The Contributed Installation Cost, per fixture, shall be equal to the cost shown on Tariff Part II, Appendix A – Exhibit III, for Street Light Luminaire.

(c) Customer Fixtures: Customer fixtures refer to all customer provided and installed street lighting equipment, including brackets, luminaires, and wire required for connection by the Company to a designated point on the Company's existing distribution facilities. Such fixtures must be contiguous, and installed on customer provided and installed poles located in areas which allow them to be clearly discernable from non-customer owned street light facilities. Customer fixtures and poles must be installed in accordance with the current edition of the National Electrical Code, as well as equipment standards established and approved by the Company. Any necessary maintenance, repairs, or replacements to Customer Fixtures or poles, including lamp and control switch replacements, or luminaire cleaning, shall be made by the customer.

(d) Fixture Service: Fixture Service refers to the lamp replacement and luminaire cleaning by the Company on a scheduled basis as well as non-scheduled fixture maintenance or replacements as may be necessary. Such non-scheduled Fixture Service shall be made, where practicable, within 72 hours of notification. Fixture Service is provided for Company Fixtures and Contribution Fixtures only. Customer Fixtures currently being provided Limited Fixture Service (limited to lamp and control switch replacement plus luminaire cleaning), may continue such Service at the stated Customer Fixture Charge plus **$1.18** per Billing Month. However, Limited Fixture Service is not available for new Customer Fixture installations.

(e) Street Light Poles: Street Light Poles are defined as poles installed for street lighting purposes which are not "standard wood distribution-type poles". These street light poles are typically used for underground distribution applications, and would include aluminum, laminated wood and fiberglass poles. Street Light Poles are installed only upon payment of a non-refundable contribution determined under Appendix A (See Tariff Part II) charges when applicable, or otherwise under fixed-price billing work order costs. Street Light Poles which have previously been installed at the Company's cost shall be billed at the monthly Street Light Pole Charge set forth in Special Provision (b), or the customer may make a payment equivalent to the current installed cost of a similar pole. Street light poles may be provided on private property roadways and associated parking areas, such as apartment building and townhouse complexes. Wood distribution type

Service Classification SVL
Sodium Vapor Street Lighting Service

(Continued) poles typically required for street light installations served from overhead distribution facilities shall be considered as distribution poles rather than street light poles. When such poles include the mounting of street lighting fixtures provided under this Service Classification, they shall be considered as "fixture-poles" and will be installed, with their associated street lighting wire, without charge to the customer. "Span-poles", which are installed to carry wire to "fixture-poles", shall be installed with their associated wire only upon payment of a non-refundable contribution determined under Appendix A charges (see Tariff Part II) when applicable, or otherwise under billing work order cost estimates. Both fixture-poles and span-poles are installed only along public roadways, or for the extension of existing street lighting service on municipal or governmental properties.

(f) General: The Company reserves the right to modify from time to time its specifications relating to street lighting equipment and its installation in order to meet changing conditions. Installations subject to vandalism may be removed at the option of the Company, unless such maintenance costs are provided by the customer.

SPECIAL PROVISIONS:

(a) Seasonal Service: Such Service will be rendered when the cost of disconnection and reconnection is paid by the customer. During such months of disconnection, the Billing Month KWH for the light will be zero, such that the per KWH charges for BGS Energy and Reconciliation Charges, Transmission Charge, Non-utility Generation Charge, Societal Benefits Charge, RGGI Recovery Charge, Zero Emission Certificate Recovery Charge, Tax Act Adjustment and JCP&L Lost Revenue Adjustment Mechanism Charge will not be billed. The monthly Fixture Charge, the JCP&L Reliability Plus Charge and a seasonal Distribution Charge will be billed during such months of disconnection. The seasonal Distribution Charge will be equal to the Billing Month KWH for the light on a standard illumination schedule, times the per KWH Distribution Charge.

(b) Street Light Pole Charge: Where the Company has installed, at its cost, a pole other than a wood distribution pole for a lamp fixture, a per Billing Month Pole Charge of **$9.88** shall be added to the Fixture Charge specified. Such charge shall not be applicable to a Street Light Pole which has had its installation cost paid for by the customer.

(c) Reduced Lighting Hours: This Special Provision is restricted to previously installed municipal parking lot lighting where the customer desires that energy for such lighting be conserved by having the Service inoperative for six hours per night and the customer reimburses the Company for the cost of any labor and materials required to provide such time control. The Billing Month KWH for lights under this Special Provision will be reduced based on 2010 annual burning hours. The monthly bill shall be the total of 1) the full monthly Fixture Charge plus 2) the reduced Billing Month KWH times all per KWH charges (BGS Energy and Reconciliation Charges, Transmission Charge, Distribution Charge, Non-utility Generation Charge, Societal Benefits Charge, RGGI Recovery Charge, Zero Emission Certificate Recovery Charge, Tax Act Adjustment and JCP&L Lost Revenue Adjustment Mechanism Charge), plus 3) a reduced lighting hours adjustment equal to the Billing Month KWH difference between the standard illumination schedule and the reduced lighting hours schedule for the light, times the per KWH Distribution Charge; plus 4) the full monthly JCP&L Reliability Plus Charge.

ADDITIONAL MODIFYING RIDER: This Service Classification may also be modified for other Rider(s) subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

Service Classification MVL
Mercury Vapor Street Lighting Service

RESTRICTION: Service Classification MVL is in process of elimination and is withdrawn except for the installations of customers receiving Service hereunder on July 21, 1982, and only for the specific premises and class of service of such customer served hereunder on such date.

APPLICABLE TO USE OF SERVICE FOR: Series and multiple circuit street lighting service operating on a standard illumination schedule of 4200 hours per year supplied from overhead or underground facilities on streets and roads where required by City, Town, County, State or other Municipal or Public Agency or by an incorporated association of local residents. At the option of the Company, Service may also be provided for lighting service on streets, roads or parking areas on municipal or private property where supplied directly from the Company's facilities when such Service is contracted for by the owner or agency operating such property.

CHARACTER OF SERVICE: Mercury vapor lighting for limited period (dusk to dawn) at secondary voltage or on constant current series circuits.

RATE PER BILLING MONTH (All charges include Sale and Use Tax as provided in Rider SUT):
(A) FIXTURE CHARGE:

Nominal Ratings Lamp Wattage	Lamp & Ballast Wattage	Billing Month KWH *	Company Fixture	Contribution Fixture	Customer Fixture
100	121	42	**$ 5.17**	**$ 1.96**	**$ 1.00**
175	211	74	**$ 5.17**	**$ 1.96**	**$ 1.00**
250	295	103	**$ 5.17**	**$ 1.96**	**$ 1.00**
400	468	164	**$ 5.61**	**$ 1.96**	**$ 1.00**
700	803	281	**$ 6.79**	**$ 1.96**	**$ 1.00**
1000	1135	397	**$ 6.79**	**$ 1.96**	**$ 1.00**

* Based on standard illumination schedule of 4200 hours per year. Billing Month KWH is calculated to the nearest whole KWH based on the nominal lamp & ballast wattage of the light, times the light's annual burning hours per year, divided by 12 months per year, divided by 1000 watts per KWH.

(B) KWH CHARGES: The following charges apply to all Billing Month KWH and to all billing months (January through December). All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)
2) **Transmission Charge: $0.000000** per KWH

DELIVERY SERVICE (Distribution Charge includes Corporation Business Tax as provided in Rider CBT):

1) **Distribution Charge: $0.057275** per KWH
2) **Non-utility Generation Charge (Rider NGC): See Rider NGC for rate** per KWH
3) **Societal Benefits Charge (Rider SBC): See Rider SBC for rate** per KWH
4) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
5) **Zero Emission Certificate Recovery Charge (Rider ZEC): See Rider ZEC for rate** per KWH
6) **Tax Act Adjustment (Rider TAA): See Rider TAA for rate** per KWH
7) **JCP&L Reliability Plus Charge (Rider RP): See Rider RP for rate** per Fixture
8) **JCP&L Lost Revenue Adjustment Mechanism Charge (Rider LRAM): See Rider LRAM for rate** per KWH

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Service Classification MVL
Mercury Vapor Street Lighting Service

TERM OF CONTRACT: Five years for each Company Fixture installation and thereafter on a monthly basis. Where special circumstances apply or special or unusual facilities are supplied, contracts of more than five years may be required. Service which is terminated before the end of the contract term shall be billed the total of 1) the light's monthly Fixture Charge plus 2) the per KWH Distribution Charge applicable to the light's Billing Month KWH, times the remaining months of the contract term. Restoration of Service to lamps before the end of the contract term shall be made at the expense of the customer.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill. Overdue bills thereafter become subject to a late payment charge as described in Section 3.19, Part II.

FACILITIES:

(a) Company Fixtures: Company Fixtures refer to all street lighting equipment including brackets and luminaires installed by the Company at its expense in accordance with its standard specifications, and all other equipment necessary in rendering the required Service installed on wood distribution poles or Street Light Poles. Company Fixtures shall be owned, operated, maintained and serviced by the Company.

(b) Contribution Fixtures: Contribution Fixtures refer to Company Fixtures for which installation the customer has paid the following Contributed Installation Cost. Contribution Fixtures shall be owned, operated, maintained and serviced by the Company. The per Billing Month charges for Contribution Fixtures shall be discontinued only upon payment of a **$35.57** charge per fixture to cover the cost of removal.

Contributed Installation Cost:	Lamp Wattage	Lamp Wattage	Lamp Wattage
	100, 175, & 250	400	700 & 1000
For currently installed fixture:	**$141.33**	**$159.49**	**$210.97**

(c) Customer Fixtures: Customer fixtures refer to all customer provided and installed street lighting equipment, including brackets, luminaires, and wire required for connection by the Company to a designated point on the Company's existing distribution facilities. Such fixtures must be contiguous, and installed on customer provided and installed poles located in areas which allow them to be clearly discernable from non-customer owned street light facilities. Customer fixtures and poles must be installed in accordance with the equipment standards established and approved by the Company. Any necessary maintenance, repairs, or replacements to Customer Fixtures or poles, including lamp and control switch replacements, or luminaire cleaning, shall be made by the customer.

(d) Fixture Service: Fixture Service refers to the lamp replacement and luminaire cleaning by the Company on a scheduled basis as well as non-scheduled fixture maintenance or replacements as may be necessary. Such non-scheduled Fixture Service shall be made, where practicable, within 72 hours of notification. Customer Fixtures currently being provided Limited Fixture Service (limited to lamp and control switch replacement plus luminaire cleaning), may continue such Service at an additional cost of **$0.96** per Billing Month.

Service Classification MVL
Mercury Vapor Street Lighting Service

(e) Street Light Poles: Street Light Poles refer to all poles other than wood distribution poles, installed, owned and maintained by the Company for street lighting service. Street Light Poles are provided only upon payment by the customer for the installation cost of such pole. Street Light Poles which have previously been installed at the Company's cost, shall be billed at the per Billing Month Street Light Pole Charge set forth in Special Provision (b), or the customer may make a **$345.22** payment to cover the cost of such previous installation.

(f) General: The Company reserves the right to modify from time to time its specifications relating to street lighting equipment and its installation in order to meet changing conditions. Installations subject to vandalism may be removed at the option of the Company, unless such maintenance costs are provided by the customer.

SPECIAL PROVISIONS:

(a) Seasonal Service: Such Service will be rendered when the cost of disconnection and reconnection is paid by the customer. During such months of disconnection, the Billing Month KWH for the light will be zero, such that the per KWH charges for BGS Energy and Reconciliation Charges, Transmission Charge, Non-utility Generation Charge, Societal Benefits Charge, RGGI Recovery Charge, Zero Emission Certificate Recovery Charge, Tax Act Adjustment and JCP&L Lost Revenue Adjustment Mechanism Charge will not be billed. The monthly Fixture Charge, the JCP&L Reliability Plus Charge and a seasonal Distribution Charge will be billed during such months of disconnection. The seasonal Distribution Charge will be equal to the Billing Month KWH for the light on a standard illumination schedule, times the per KWH Distribution Charge.

(b) Street Light Pole Charge: Where the Company has installed, at its cost, a pole other than a wood distribution pole for a lamp fixture, a per Billing Month Pole Charge of **$9.88** shall be added to the Fixture Charge specified. Such charge shall not be applicable to a Street Light Pole which has had its installation cost paid for by the customer.

ADDITIONAL MODIFYING RIDER: This Service Classification may also be modified for other Rider(s) subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

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Service Classification ISL
Incandescent Street Lighting Service

RESTRICTION: Service Classification ISL is in process of elimination and is withdrawn except for the installations of customers currently receiving Service, and except for fire alarm and police box lamps provided under Special Provision (c). The obsolescence of this Service Classification's facilities further dictates that Service be discontinued to any installation that requires the replacement of a fixture, bracket or street light pole.

APPLICABLE TO USE OF SERVICE FOR: Series and multiple circuit street lighting service operating on a standard illumination schedule of 4200 hours per year supplied from overhead or underground facilities on streets or roads where required by city, town, county, State or other principal or public agency or by an incorporated association of local residents.

CHARACTER OF SERVICE: Incandescent lighting for limited period (dusk to dawn) at secondary voltage or on constant current series circuits.

RATE PER BILLING MONTH (All Charges include Sales and Use Tax as provided in Rider SUT):

(A) FIXTURE CHARGE:

Nominal Ratings Lamp Wattage	Billing Month KWH *	Company Fixture	Customer Fixture
105	37	**$ 2.19**	**$ 1.00**
205	72	**$ 2.19**	**$ 1.00**
327	114	**$ 2.19**	**$ 1.00**
448	157	**$ 2.19**	**$ 1.00**
690	242	**$ 2.19**	**$ 1.00**
860	301	**$ 2.19**	**$ 1.00**

* Based on standard illumination schedule of 4200 hours per year. Billing Month KWH is calculated to the nearest whole KWH based on the nominal lamp & ballast wattage of the light, times the light's annual burning hours per year, divided by 12 months per year, divided by 1000 watts per KWH.

(B) KWH CHARGES: The following charges apply to all Billing Month KWH and to all billing months (January through December). All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)
2) **Transmission Charge: $0.000000** per KWH

DELIVERY SERVICE (Distribution Charge includes Corporation Business Tax as provided in Rider CBT):

1) **Distribution Charge: $0.057275** per KWH
2) **Non-utility Generation Charge (Rider NGC): See Rider NGC for rate** per KWH
3) **Societal Benefits Charge (Rider SBC): See Rider SBC for rate** per KWH
4) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
5) **Zero Emission Certificate Recovery Charge (Rider ZEC): See Rider ZEC for rate** per KWH
6) **Tax Act Adjustment (Rider TAA): See Rider TAA for rate** per KWH
7) **JCP&L Reliability Plus Charge (Rider RP): See Rider RP for rate** per Fixture
8) **JCP&L Lost Revenue Adjustment Mechanism Charge (Rider LRAM): See Rider LRAM for rate** per KWH

Service Classification ISL
Incandescent Street Lighting Service

TERM OF CONTRACT: Five years for each Company Fixture installation and thereafter on a monthly basis. Where special circumstances apply or special or unusual facilities are supplied, contracts of more than five years may be required. Service which is terminated before the end of the contract term shall be billed the total of 1) the light's monthly Fixture Charge plus 2) the per KWH Distribution Charge applicable to the light's Billing Month KWH, times the remaining months of the contract term.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill. Overdue bills thereafter become subject to a late payment charge as described in Section 3.19, Part II.

FACILITIES:

(a) Company Fixtures: Company Fixtures refer to all street lighting equipment including brackets and luminaires installed by the Company at its expense in accordance with its standard specifications, and all other equipment necessary in rendering the required Service, installed on wood distribution poles or Street Light Poles. Company Fixtures shall be owned, operated, maintained and serviced by the Company.

(b) Customer Fixtures: Customer fixtures refer to all customer provided and installed street lighting equipment, including brackets, luminaires, and wire required for connection by the Company to a designated point on the Company's existing distribution facilities. Such fixtures must be contiguous, and installed on customer provided and installed poles located in areas which allow them to be clearly discernable from non-customer owned street light facilities. Customer fixtures and poles must be installed in accordance with the equipment standards established and approved by the Company. Any necessary maintenance, repairs, or replacements to Customer Fixtures or poles, including lamp and control switch replacements, or luminaire cleaning, shall be made by the customer.

(c) Fixture Service: Fixture Service refers to the lamp replacement and luminaire cleaning by the Company on a scheduled basis as well as non-scheduled lamp and control switch replacement as may be necessary. Such non-scheduled Fixture Service shall be made, where practicable, within 72 hours of notification. Customer fixtures currently being provided limited Fixture Service (limited to lamp and control switch replacement plus luminaire cleaning), may continue such Service at the stated Customer Fixture Charge plus **$1.18** per Billing Month.

(d) Street Light Poles: Street Light Poles refer to all poles, other than wood distribution poles, installed, owned and maintained by the Company for street lighting service. Replacement of Street Light Poles shall be provided only upon payment by the customer for the current installation cost of such replacement poles except when occasioned and such cost recoverable by a third party.

(e) General: The Company reserves the right to modify from time to time its specifications relating to street lighting equipment and its installation in order to meet changing conditions. Installations subject to vandalism may be removed at the option of the Company, unless such maintenance costs are provided by the customer.

Service Classification ISL
Incandescent Street Lighting Service

SPECIAL PROVISIONS:

(a) Seasonal Service: Such Service will be rendered when the cost of disconnection and reconnection is paid by the customer. During such months of disconnection, the Billing Month KWH for the light will be zero, such that the per KWH charges for BGS Energy and Reconciliation Charges, Transmission Charge, Non-utility Generation Charge, Societal Benefits Charge, RGGI Recovery Charge, Zero Emission Certificate Recovery Charge, Tax Act Adjustment and JCP&L Lost Revenue Adjustment Mechanism Charge will not be billed. The monthly Fixture Charge, the JCP&L Reliability Plus Charge and a seasonal Distribution Charge will be billed during such months of disconnection. The seasonal Distribution Charge will be equal to the Billing Month KWH for the light on a standard illumination schedule, times the per KWH Distribution Charge.

(b) Fire Alarm and Police Box Lamp Charge: 25 watt lamps serviced by the Company and served from existing secondary facilities will be billed a monthly Fixture Charge of **$1.28** and **$0.36** for lamps with individual time controls operated on a standard illumination schedule, and lamps operated 24 hours per day, respectively. Lamps with individual time controls operated on a standard illumination schedule will have a Billing Month KWH of 9 KWH. Lamps operated 24 hours per day will have a Billing Month KWH of 18 KWH. All per KWH charges (BGS Energy and Reconciliation Charges, Transmission Charge, Distribution Charge, Non-utility Generation Charge, Societal Benefits Charge, RGGI Recovery Charge, Zero Emission Certificate Recovery Charge, Tax Act Adjustment and JCP&L Lost Revenue Adjustment Mechanism Charge) will be billed based on the applicable lamp's Billing Month KWH.

ADDITIONAL MODIFYING RIDER: This Service Classification may also be modified for other Rider(s) subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

Service Classification LED
LED Street Lighting Service

APPLICABLE TO USE OF SERVICE FOR: Service Classification LED is available for installation of 12 or more LED (light emitting diode) fixtures per request for series and multiple circuit street lighting Service operating on a standard illumination schedule of 4200 hours per year supplied from overhead or underground facilities along public streets and roadways, or for the extension of existing street lighting service on municipal or governmental properties (and parking areas at the option of the Company) where required by City, Town, County, State or other Municipal or Public Agency or by an incorporated association of local residents.

CHARACTER OF SERVICE: LED lighting service is for limited period (dusk to dawn). Standard Service shall be supplied from existing lines, using the Company's standard fixtures and other appurtenances on existing wood distribution poles unrestricted as to their use by Company for purposes other than street lighting, on which existing wood distribution poles the required secondary voltage is present. The rating of the fixture in lumens is for identification and is intended to approximate the manufacturer's standard rating.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
(A) FIXTURE CHARGE:

COMPANY FIXTURES: Company Fixtures refer to fixtures installed by the Company in accordance with Standard Service and its specifications at its expense. Company Fixtures shall be owned, operated, maintained and serviced by the Company.

COMPANY FIXTURE

Lamp Wattage	Type	Lumens	Billing Month KWH*	Company Fixture
30	Cobra Head	2400	11	**$ 7.40**
50	Cobra Head	4000	18	**$ 7.36**
90	Cobra Head	7000	32	**$ 7.95**
130	Cobra Head	11500	46	**$ 9.04**
260	Cobra Head	24000	91	**$ 11.49**
50	Acorn	2500	18	**$ 18.83**
90	Acorn	5000	32	**$ 18.19**
50	Colonial	2500	18	**$ 10.58**
90	Colonial	5000	32	**$ 12.71**

CONTRIBUTION FIXTURES: Contribution Fixtures refer to fixtures installed by the Company in accordance with Standard Service and its specifications for which installation the customer has paid the Contributed Installation Cost. The Company provides two contribution levels for the Contributed Installation Cost, at the Customer's option, that have different corresponding monthly charges. Contribution Fixtures shall be owned, operated, maintained and serviced by the Company. Contribution Fixture service does not include or provide for the replacement of the fixture at failure or end of life. A contribution payment to JCP&L shall not give the customer any interest in the facilities, the ownership being vested exclusively in JCP&L.

Contributed Installation Cost: The Contributed Installation Cost, per fixture, shall be equal to the cost shown on Tariff Part II, Appendix A – Exhibit III, for Street Light Luminaire, which costs are subject to gross-up for applicable income taxes.

JERSEY CENTRAL POWER & LIGHT COMPANY

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Service Classification LED
LED Street Lighting Service

CONTRIBUTION FIXTURE (a)

Fixture Wattage	Type	Lumens	Billing Month KWH*	Fixture Charge	Contribution Fixture (a)
30	Cobra Head	2400	11	$ 2.65	$ 358.38
50	Cobra Head	4000	18	$ 2.65	$ 354.88
90	Cobra Head	7000	32	$ 2.65	$ 403.55
130	Cobra Head	11500	46	$ 2.65	$ 492.97
260	Cobra Head	24000	91	$ 2.65	$ 694.22
50	Acorn	2500	18	$ 2.65	$1,295.80
90	Acorn	5000	32	$ 2.65	$1,243.30
50	Colonial	2500	18	$ 2.65	$ 619.38
90	Colonial	5000	32	$ 2.65	$ 793.88

CONTRIBUTION FIXTURE (b)

Fixture Wattage	Type	Lumens	Billing Month KWH*	Fixture Charge	Contribution Fixture (b)
30	Cobra Head	2400	11	$ 4.24	$ 209.20
50	Cobra Head	4000	18	$ 4.24	$ 205.70
90	Cobra Head	7000	32	$ 4.24	$ 254.37
130	Cobra Head	11500	46	$ 4.24	$ 343.79
260	Cobra Head	24000	91	$ 4.24	$ 545.04
50	Acorn	2500	18	$ 4.24	$1,146.62
90	Acorn	5000	32	$ 4.24	$1,094.12
50	Colonial	2500	18	$ 4.24	$ 470.20
90	Colonial	5000	32	$ 4.24	$ 644.70

* Based on standard illumination schedule of 4200 hours per year. Billing Month KWH is calculated to the nearest whole KWH based on the wattage of the fixture, times the fixture's annual burning hours per year, divided by 12 months per year, divided by 1000 watts per KWH.

(B) KWH CHARGES: The following charges apply to all Billing Month KWH and to all billing months (January through December). All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)
2) **Transmission Charge: $0.000000** per KWH

DELIVERY SERVICE (Distribution Charge includes Corporation Business Tax as provided in Rider CBT):

1) **Distribution Charge: $0.057275** per KWH
2) **Non-utility Generation Charge (Rider NGC): See Rider NGC for rate** per KWH
3) **Societal Benefits Charge (Rider SBC): See Rider SBC for rate** per KWH
4) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
5) **Zero Emission Certificate Recovery Charge (Rider ZEC): See Rider ZEC for rate** per KWH
6) **Tax Act Adjustment (Rider TAA): See Rider TAA for rate** per KWH
7) **JCP&L Reliability Plus Charge (Rider RP): See Rider RP for rate** per Fixture
8) **JCP&L Lost Revenue Adjustment Mechanism Charge (Rider LRAM): See Rider LRAM for rate** per KWH

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Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 14 ELECTRIC - PART III Original Sheet No. 39

Service Classification LED
LED Street Lighting Service

TERM OF CONTRACT: Fifteen years for each fixture installation and thereafter on a monthly basis. Where special circumstances apply or special or unusual facilities are supplied, contracts of more than fifteen years may be required. Service which is terminated before the end of the contract term shall be billed the total of 1) the fixture's monthly Fixture Charge plus 2) the per KWH Distribution Charge applicable to the fixture's Billing Month KWH, times the remaining months of the contract term.

TERMS OF PAYMENT: Bills are due when rendered by the Company and become overdue when payment is not received by the Company on or before the due date specified on the bill. Overdue bills thereafter become subject to a late payment charge as described in Section 3.19, Part II.

MISCELLANEOUS:

Non-Standard Installations: Where the installation of additional facilities, including, but not limited to: poles, wire, transformers, and brackets, is required to provide service to a fixture, Customers shall be responsible for payment of a non-refundable Contribution in Aid of Construction determined under Appendix A charges (see Tariff Part II) when applicable, or otherwise under billing work order costs estimates, which costs are subject to gross-up for applicable income taxes.

(a) Changes in Fixture Wattage, Type or Location: Customers will be required to pay the cost for relocation, changes in fixture wattage, fixture type, color (Kelvin temperature) and conversion from an LED light source to another when the age of the fixture is less than 15 years. These costs will include removal cost less salvage and installation cost of the fixture. Except for relocations, the cost will also include the remaining net book value of the existing fixture and, in the case of Contribution Fixtures, payment of the Contributed Installation Cost.

i) Installation of a new fixture at the same location of the removal of an existing fixture within 12 months will be considered a replacement of the existing fixture and will be subject to charges including the removal cost less salvage for the fixture removed, the installation cost of the new fixture and, if applicable, any Contribution Installation Cost.

ii) LED conversions of sodium vapor, mercury vapor or incandescent fixtures shall be scheduled at the Company's reasonable discretion. JCP&L reserves the right to limit the number of fixtures conversions in any year to no more than 5% of the total fixtures served at the end of the previous year.

(b) Traffic Control: The Municipality will be responsible for providing and paying the costs of police assistance when deemed necessary by local authorities. The Company will provide basic traffic control (flaggers) at no cost to the Municipality. When traffic control (flagging) labor hours exceed construction labor hours (considered non-basic traffic control) the Municipality will be responsible for paying the differential in costs between basic and non-basic traffic control. The Municipality will also be responsible for all fees associated with required permitting.

(c) Seasonal Service: Such Service will be rendered when the cost of disconnection and reconnection is paid by the customer. During such months of disconnection, the Billing Month KWH for the fixture will be zero. Only the monthly Fixture Charge and a seasonal Distribution Charge will be billed (i.e., Basic Generation Service and other Delivery Service charges will not be billed) during such months of disconnection. The seasonal Distribution Charge will be equal to the Billing Month KWH for the light on a standard illumination schedule, times the per KWH Distribution Charge.

(d) General: The Company reserves the right to modify from time to time its specifications relating to street lighting equipment and its installation in order to meet changing conditions. Installations subject to vandalism may be removed at the option of the Company, unless such maintenance costs are provided by the customer.

Service Classification LED
LED Street Lighting Service

MISCELLANEOUS: (Continued)

Retrofitting of existing, non-LED street lighting: Where requested, the following shall be implemented on an interim basis, pending the resolution of the Board's current stakeholder proceeding addressing LED street lighting issues:

Option 1:

Upon failure, which shall be determined in the Company's sole discretion, and at the Customer's direction, which direction shall be set forth in an LED Replacement Agreement, the Company will replace a non-LED streetlight luminaire with an LED streetlight luminaire.

Option 2:

Where Customer requests replacement of existing non-LED streetlight luminaire with an LED streetlight luminaire, prior to its failure, the Customer is responsible for a one-time payment of the estimated average undepreciated luminaire cost (i.e., net book value) of the existing non-LED streetlight luminaire as set forth in the table below, prior to installation of the replacement LED streetlight.

Option 3:

Where Customer requests replacement of existing non-LED streetlight luminaire with an LED streetlight luminaire, prior to its failure, the Customer shall enter into a Payment Agreement with the Company and shall be responsible for payment for the estimated average undepreciated non-LED luminaire cost (i.e., net book value) of the existing non-LED streetlight luminaire in equal payments over a 60-month period, as set forth in the table below. In the event of termination of service under this Schedule, for any reason prior to the expiration of the Payment Agreement, prior to termination of service, the Customer shall pay to the Company any and all amounts due under the Payment Agreement and all costs associated with removal of the LED streetlights.

LED Streetlight – Stranded Costs

SVL

	Option #2 One-time Payment	Option #3 Equal Payment 60-month Period
Cobra Head	$352	$7.36
Acorn	$861	$18.01
Colonial	$493	$10.31

MVL

	Option #2 One-time Payment	Option #3 Equal Payment 60-month Period
Cobra Head	$201	$4.21
Acorn	$509	$10.65
Colonial	$287	$6.00

Special Contract Service: Where requested, negotiated contract service will be provided on an individual basis at the Company's reasonable discretion and at the Customer's cost. Such contracts shall incorporate the terms and conditions of this Tariff for Service and may include additional terms and conditions regarding advanced functionality and associated equipment, including but not limited to: controllers; dimming capabilities; sensors; or other network enabled functions. Customer contracts for this service will be submitted to the BPU for approval, unless and until the Company is otherwise directed by the BPU.

ADDITIONAL MODIFYING RIDER: This Service Classification may also be modified for other Rider(s) subject to each Rider's applicability, as specified.

STANDARD TERMS AND CONDITIONS: This Service Classification is subject to the Standard Terms and Conditions of this Tariff for Service.

JERSEY CENTRAL POWER & LIGHT COMPANY

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Rider BGS-RSCP
Basic Generation Service – Residential Small Commercial Pricing
(Applicable to Service Classifications RS, RT, RGT, GS, GST, OL, SVL, MVL, ISL and LED)

Effective June 1, 2015, Rider BGS-FP (Basic Generation Service – Fixed Pricing) is renamed Rider BGS-RSCP to comply with the BPU Order dated November 24, 2014 (Docket No. ER14040370).

AVAILABILITY: Rider BGS-RSCP is available to and provides Basic Generation Service (default service) charges applicable to all KWH usage for Full Service Customers taking service at secondary voltages under Service Classifications RS, RT, RGT, GS, GST, OL, SVL, MVL, ISL and LED, except for GS and GST customers that have a peak load share of 500 KW or greater as of November 1, 2021. Rider BGS-RSCP-eligible GS and GST customers may elect to take default service under Rider BGS-CIEP no later than the second business day in January of each year. Such election will be effective June 1 of that year and Rider BGS-CIEP will remain the customer's default service for the entire 12-month period from June 1 through May 31 of the following year. BGS-RSCP-eligible customers who have elected to take default service under BGS-CIEP may return to BGS-RSCP by notifying the Company no later than the second business day in January of each year. Such notification to return to BGS-RSCP will become effective June 1 of that year.

RATE PER BILLING MONTH: (For service rendered effective June 1, 2022 through May 31, 2023)
1) BGS Energy Charge per KWH: (All charges include Sales and Use Tax as provided in Rider SUT.)

Service Classification	June through September	October through May
RS - first 600 KWH	**$0.071484**	
- all KWH over 600	**$0.080709**	
- all KWH		**$0.081471**
(Excludes off-peak and controlled water heating special provisions)		
RT - all on-peak KWH	**$0.102557**	**$0.103818**
- all off-peak KWH	**$0.054151**	**$0.057373**
RGT - all on-peak KWH	**$0.102557**	
- all off-peak KWH	**$0.054151**	
- all KWH		**$0.081471**
RS and GS Water Heating – all KWH	**$0.074607**	**$0.074395**
(For separately metered off-peak and controlled water heating usage under applicable special provisions)		
GS - all KWH	**$0.074746**	**$0.074466**
(Excludes off-peak and controlled water heating special provisions)		
GST - all on-peak KWH	**$0.094431**	**$0.088547**
- all off-peak KWH	**$0.054711**	**$0.056672**
OL, SVL, MVL, ISL, LED - all KWH	**$0.057863**	**$0.058494**

BGS Energy Charges above reflect costs for energy, generation capacity, ancillary services and related cost.

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Rider BGS-RSCP
Basic Generation Service – Residential Small Commercial Pricing
(Applicable to Service Classifications RS, RT, RGT, GS, GST, OL, SVL, MVL, ISL and LED)

2) BGS Transmission Charge per KWH: As provided in the respective tariff for Service Classifications RS, RT, RGT, GS, GST, OL, SVL, MVL, ISL and LED. Effective September 1, 2019, a RMR surcharge of **$0.000000** per KWH (includes Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage.

Effective **December 15, 2021**, the following TEC surcharges (include Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage, except lighting under Service Classifications OL, SVL, MVL, ISL and LED:

EL18-680FM715-TEC surcharge of **$0.000000** per KWH

Effective **April 1, 2022**, the following TEC surcharges (include Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage, except lighting under Service Classifications OL, SVL, MVL, ISL and LED:

PSEG-TEC surcharge of **$0.002959** per KWH
VEPCO-TEC surcharge of **$0.000300** per KWH
PATH-TEC surcharge of **$0.000007** per KWH
AEP-East-TEC surcharge of **$0.000076** per KWH
MAIT-TEC surcharge of **$0.000076** per KWH
EL05-121-TEC surcharge of **$0.000235** per KWH
SRE-TEC surcharge of **$0.000200** per KWH
NIPSCO-TEC surcharge of **$0.000002** per KWH
SFC-TEC surcharge of **$0.000004** per KWH

Effective **September 1, 2022**, the following TEC surcharges (include Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage, except lighting under Service Classifications OL, SVL, MVL, ISL and LED:
TRAILCO-TEC surcharge of **$0.000208** per KWH
ACE-TEC surcharge of **$0.000098** per KWH
PECO-TEC surcharge of **$0.000068** per KWH
PPL-TEC surcharge of **$0.000643** per KWH
Delmarva-TEC surcharge of **$0.000005** per KWH
PEPCO-TEC surcharge of **$0.000013** per KWH
BG&E-TEC surcharge of **$0.000016** per KWH
COMED-TEC surcharge of **$0.000000** Per KWH
Duquesne-TEC surcharge of **$0.000000** Per KWH

3) BGS Reconciliation Charge per KWH: ($0.001659) (includes Sales and Use Tax as provided in Rider SUT)
The above BGS Reconciliation Charge recovers the difference between the costs for the provision of Basic Generation Service and the revenues from BGS customers for Basic Generation Service and is subject to quarterly true-ups.

Rider BGS-CIEP
Basic Generation Service – Commercial Industrial Energy Pricing
(Applicable to Service Classifications GP and GT and Certain Customers under Service Classifications GS and GST)

AVAILABILITY: Rider BGS-CIEP is available to and provides Basic Generation Service (default service) charges applicable to all Full Service Customers taking service at primary and transmission voltages under Service Classifications GP and GT and any Full Service Customers taking service at secondary voltages under Service Classifications GS and GST that have a peak load share of 500 KW or greater as of November 1, 2021, or that have elected to take BGS-CIEP service no later than the second business day in January of each year. All BGS-CIEP customers remain subject to this Rider for the entire 12-month period from June 1 of any given year through May 31 of the following year.

RATE PER BILLING MONTH:
(For service rendered effective June 1, 2022 through May 31, 2023)

1) BGS Energy Charge per KWH: The sum of actual real-time PJM load weighted average Residual Metered Load Aggregate Locational Marginal Price for JCP&L Transmission Zone and ancillary services of **$0.00600** per KWH, times the Losses Multiplier provided below, times 1.06625 multiplier for Sales and Use Tax as provided in Rider SUT.

Losses Multiplier:	GT – High Tension Service	1.005
	GT	1.027
	GP	1.047
	GST	1.103
	GS	1.103

2) BGS Capacity Charge per KW of Generation Obligation: $0.25480 per KW-day times BGS-CIEP customer's share of the capacity peak load assigned to the JCP&L Transmission Zone by the PJM Interconnection, L.L.C., as adjusted by PJM assigned capacity related factors, times 1.06625 multiplier for Sales and Use Tax as provided in Rider SUT.

3) BGS Transmission Charge per KWH: As provided in the respective tariff for Service Classifications GS, GST, GP and GT. Effective September 1, 2019, a RMR surcharge will be added to the BGS Transmission Charge applicable to all KWH usage, as follows (includes Sales and Use Tax as provided in Rider SUT):

GT – High Tension Service	**$0.000000**
GT	**$0.000000**
GP	**$0.000000**
GS and GST	**$0.000000**

Rider BGS-CIEP
Basic Generation Service – Commercial Industrial Energy Pricing
(Applicable to Service Classifications GP and GT and Certain Customers under Service Classifications GS and GST)

3) BGS Transmission Charge per KWH: (Continued)

Effective **December 15, 2021**, the following TEC surcharges (include Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage:

	EL18-680Fm715-TEC
GS and GST	**$0.000000**
GP	**$0.000000**
GT	**$0.000000**
GT – High Tension Service	**$0.000000**

Effective **April 1, 2022**, the following TEC surcharges (include Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage:

	PSEG-TEC	VEPCO-TEC	PATH-TEC	AEP-East-TEC	
GS and GST	**$0.002959**	**$0.000300**	**$0.000007**	**$0.000076**	
GP	**$0.001800**	**$0.000182**	**$0.000004**	**$0.000046**	
GT	**$0.001581**	**$0.000160**	**$0.000004**	**$0.000041**	
GT – High Tension Service	**$0.000425**	**$0.000043**	**$0.000001**	**$0.000011**	
	MAIT-TEC	EL05-121-TEC	SRE-TEC	NIPSCO-TEC	SFC-TEC
GS and GST	**$0.000076**	**$0.000235**	**$0.000200**	**$0.000002**	**$0.000004**
GP	**$0.000046**	**$0.000143**	**$0.000122**	**$0.000001**	**$0.000002**
GT	**$0.000041**	**$0.000126**	**$0.000107**	**$0.000001**	**$0.000002**
GT – High Tension Service	**$0.000011**	**$0.000034**	**$0.000029**	**$0.000000**	**$0.000001**

Effective **September 1, 2022**, the following TEC surcharges (include Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage:

	TRAILCO-TEC	ACE-TEC	PECO-TEC	Delmarva-TEC	
GS and GST	**$0.000208**	**$0.000098**	**$0.000068**	**$0.000005**	
GP	**$0.000124**	**$0.000059**	**$0.000041**	**$0.000003**	
GT	**$0.000113**	**$0.000053**	**$0.000037**	**$0.000003**	
GT – High Tension Service	**$0.000033**	**$0.000016**	**$0.000011**	**$0.000001**	
	PPL-TEC	PEPCO-TEC	BG&E-TEC	COMED-TEC	Duquesne-TEC
GS and GST	**$0.000643**	**$0.000013**	**$0.000016**	**$0.000000**	**$0.000000**
GP	**$0.000383**	**$0.000007**	**$0.000010**	**$0.000000**	**$0.000000**
GT	**$0.000350**	**$0.000006**	**$0.000009**	**$0.000000**	**$0.000000**
GT – High Tension Service	**$0.000102**	**$0.000002**	**$0.000002**	**$0.000000**	**$0.000000**

4) BGS Reconciliation Charge per KWH: ($0.000044) (includes Sales and Use Tax as provided in Rider SUT)

The above BGS Reconciliation Charge recovers the difference between the costs for the provision of Basic Generation Service and the revenues from BGS customers for Basic Generation Service and is subject to quarterly true-ups.

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Rider CIEP – Standby Fee
Commercial Industrial Energy Pricing Standby Fee
(Applicable to Service Classifications GP and GT and Certain Customers under Service Classifications GS and GST)

Effective June 1, 2007, Rider DSSAC (Default Supply Service Availability Charge) is renamed Rider CIEP – Standby Fee to comply with the BPU Order dated December 22, 2006 (Docket No. EO06020119).

APPLICABILITY: Rider CIEP – Standby Fee provides a charge applicable to all KWH usage of all Full Service Customers or Delivery Service Customers taking service under Service Classifications GP and GT and any Full Service Customer or Delivery Service Customer taking service under Service Classifications GS and GST that has a peak load share of 500 KW or greater as of November 1, 2021, or that has elected to take Basic Generation Service-Commercial Industrial Energy Pricing under Rider-CIEP no later than the second business day in January of each year. This charge is applicable for service rendered from June 1, 2022 through May 31, 2023 to recover costs associated with administrating and maintaining the availability of the hourly-priced default Basic Generation Service for these customers.

CIEP – Standby Fee per KWH: $0.000150

(**$0.000160** including Sales and Use Tax as provided in Rider SUT)

JERSEY CENTRAL POWER & LIGHT COMPANY

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Rider NGC
Non-utility Generation Charge

APPLICABILITY: Rider NGC provides a non-utility generation charge ("NGC") applicable to all KWH usage of any Full Service Customer or Delivery Service Customer. Effective September 1, 2004, Rider MTC ("Market Transition Charge") is renamed Rider NGC to comply with the BPU Final Order dated May 17, 2004 (Docket Nos. ER02080506, etc.) that "the MTC shall be discontinued and renamed the NGC" for customer billing purposes.

Effective August 1, 2003, the Company recovers through the MTC charge, the MTC deferred balance which includes: (1) BPU-approved costs incurred during the transition to a competitive retail market and under-recovered during the period from August 1, 1999 through July 31, 2003; and (2) all BPU-approved costs associated with committed supply energy, capacity and ancillary services, net of all revenues from the sale of the committed supply in the wholesale market (Docket Nos. EX01110754 and EX01050303, etc.) Carrying cost shall be computed on a monthly basis at the applicable BPU-approved interest rate on the average net-of-tax over or under-recovered balance of the MTC, compounded annually.

Effective August 1, 2003, the composite MTC Factor shall be $0.011013 per KWH (excluding SUT), which includes the interim recovery of MTC deferred balance as of July 31, 2003, until the BPU's decision on the securitization of the MTC deferred balance.

Effective June 1, 2005, the composite MTC Factor shall be reduced to $0.010614 per KWH (excluding SUT), which includes the anticipation of the savings to be realized from the securitization of a portion of the MTC deferred balance as of July 31, 2003 ("Deferred BGS Transition Costs") pending the BPU approval. By Order dated June 8, 2006, the BPU approved the securitization of Deferred BGS Transition Costs.

Effective December 6, 2006, the composite MTC/NGC Factor shall be $0.015492 per KWH (excluding SUT), which includes an increase in the NGC Factor of $0.004878 per KWH.

Effective March 1, 2011, the composite MTC/NGC Factor shall be $0.007687 per KWH (excluding SUT), which includes a decrease in the NGC Factor of $0.007805 per KWH.

Effective March 1, 2012, the composite MTC/NGC Factor shall be $0.002839 per KWH (excluding SUT), which includes a decrease in the NGC Factor of $0.004848 per KWH.

Effective February 2, 2015, the composite MTC/NGC Factor shall be $0.003750 per KWH (excluding SUT), which includes an increase in the NGC Factor of $0.000911 per KWH.

Effective September 1, 2016, the composite MTC/NGC Factor shall be $0.005012 per KWH (excluding SUT), which includes an increase in the NGC Factor of $0.001262 per KWH. By Board Order dated May 31, 2017 (Docket No. ER16101046), the Board approved no change to this Factor for the 2015 NGC Filing.

Effective June 10, 2017, the composite MTC/NGC Factor shall be $0.001527 per KWH (excluding SUT), which includes a decrease in the NGC Factor of $0.001548 per KWH and the OC-TBC and OC-MTC-Tax associated with the securitization of Oyster Creek at zero rate. By Board Order dated September 17, 2018 (Docket No. ER17030306), the Board approved no change to this Factor for the 2016 NGC Filing.

Effective November 1, 2018, the composite MTC/NGC Factor shall be $0.000451 per KWH (excluding SUT), which includes a decrease in the NGC Factor of $0.001076 per KWH. By Board Order dated June 12, 2019 (Docket No. ER18090977), the Board approved no change to this Factor for the 2017 NGC Filing.

Effective January 1, 2020, the composite MTC/NGC Factor shall be $0.000105 per KWH (excluding SUT), which includes a decrease in the NGC Factor of $0.000346 per KWH. By Board Order dated December 2, 2020 (Docket No. ER20060473), the Board approved no change to this Factor for the 2019 NGC Filing.

Effective November 15, 2021, the MTC/NGC Factor shall be -$0.000215 per KWH (excluding SUT), with the DB-TBC and DB-MTC-Tax associated with the securitization of Deferred BGS Transition Costs at zero Rate.

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Rider NGC
Non-utility Generation Charge

For billing purposes, the composite MTC/NGC Factor of -$0.000215 per KWH shall be applied to all KWH usage of any Full Service Customer or Delivery Service Customer as follows:

Voltage Adjusted MTC Charges per KWH (renamed NGC Charges per KWH)		Including SUT
Secondary Voltages	**-$0.000219**	**-$0.000234**
(Applicable to Service Classifications RS, RT, RGT, GS, GST, OL, SVL, MVL, ISL and LED)		
Primary Voltages	**-$0.000208**	**-$0.000222**
(Applicable to Service Classification GP)		
Transmission Voltages	**-$0.000204**	**-$0.000218**
High Tension Service (230 KV)	**-$0.000200**	**-$0.000213**
(Applicable to Service Classification GT)		

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BPU No. 14 ELECTRIC - PART III **Original Sheet No. 48**

Rider NGC
Non-utility Generation Charge

Securitization of Oyster Creek

On February 6, 2002, the BPU approved and issued a Bondable Stranded Costs Rate Order ("Oyster Creek Rate Order") (Docket No. EF99080615) authorizing the issuance and sale of up to $320 million aggregate principal amount of transition bonds to recover certain bondable stranded costs related to the investment in the Oyster Creek Nuclear Generating Station, the imposition of a non-bypassable Transition Bond Charge ("OC-TBC") for the recovery of such costs and the related Market Transition Charge-Tax ("OC-MTC-Tax). The bondable stranded costs are defined in the Oyster Creek Rate Order and include: (1) the capital reduction costs, (2) the upfront transaction costs and (3) the ongoing transition bond costs.

Effective June 11, 2002, the MTC included an OC-TBC of $0.001921 per KWH and an OC-MTC-Tax of $0.000505 per KWH (or $0.002036 per KWH and $0.000535 per KWH including SUT, respectively). The OC-TBC and OC-MTC-Tax are governed by the provisions of the Oyster Creek Rate Order and are subject to periodic true-ups, at least annually but not more frequently than quarterly, except monthly true-ups are permitted in the last year before the scheduled maturity of the transition bonds and continuing until final maturity, as provided in the Oyster Creek Rate Order.

On February 28, 2017, a true-up letter was filed with the BPU in accordance with the provisions in the Oyster Creek Rate Order. Effective May 1, 2017 through May 6, 2017, the OC-TBC and OC-MTC-Tax shall be $0.001198 per KWH and $0.000739 per KWH, respectively (or $0.001280 per KWH and $0.000790 per KWH including SUT, respectively). Effective May 7, 2017, the OC-TBC and OC-MTC-Tax shall be at zero.

Securitization of Deferred BGS Transition Costs

By Order dated June 8, 2006, the BPU approved and issued a Bondable Stranded Costs Rate Order ("Deferred BGS Transition Costs Rate Order") (Docket No. ER03020133) authorizing the issuance and sale of $182.4 million aggregate principal amount of transition bonds to recover the Company's net of tax deferred basic generation service transition costs incurred during the transition period from August 1, 1999 through July 31, 2003, the imposition of a non-bypassable Transition Bond Charge ("DB-TBC") for the recovery of such costs and the related Market Transition Charge-Tax ("DB-MTC-Tax"). The bondable stranded costs are defined in the Deferred BGS Transition Costs Rate Order and include: (1) the upfront transaction costs and (2) the ongoing transition bond costs.

Effective August 10, 2006, the NGC included a DB-TBC of $0.001230 per KWH and a DB-MTC-Tax of $0.000572 per KWH (or $0.001316 per KWH and $0.000612 per KWH including SUT, respectively). The DB-TBC and DB-MTC-Tax are governed by the provisions of the Deferred BGS Transition Costs Rate Order and are subject to periodic true-ups, at least annually but not more frequently than quarterly, and continuing until final maturity, as provided in the Deferred BGS Transition Costs Rate Order.

On February 28, 2021, a true-up letter was filed with the BPU in accordance with the provisions in the Deferred BGS Transition Costs Rate Order. Effective May 1, 2021 through May 10, 2021, the DB-TBC and DB-MTC-Tax shall continue to be $0.000735 per KWH and $0.000321 per KWH, respectively (or $0.000784 per KWH and $0.000342 per KWH including SUT, respectively). Effective May 11, 2021, the DB-TBC and DB-MTC-Tax shall be at zero.

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Rider NGC
Non-utility Generation Charge

St. Lawrence Hydroelectric Power

At the November 9, 2004 agenda meeting, the BPU verbally approved, among other things, the Public Power Association of New Jersey ("PPANJ") as Bargaining Agent for the State of New Jersey to renegotiate with the New York Power Authority ("NYPA"), on the allocation of service tariff capacity and associated energy produced at the St. Lawrence/FDR project (In the Matter of the Allocation of St. Lawrence Hydroelectric Power to the State of New Jersey Docket No. EO04101124).

On December 21, 2004, the PPANJ filed with the BPU the following documents associated with the St. Lawrence Hydroelectric Power matter: 1) Agreement for Electric Service Investor Owned Utility Between the PPANJ and JCP&L, PSE&G, Rockland Electric and Atlantic City Electric Company; 2) Agreement Governing Administration of NYPA Power ("Administration Agreement"); and 3) PPANJ for State of New Jersey Service Tariff Capacity and Associated Energy.

Pursuant to the Administration Agreement, the Company, as Nominal Recipient of the Investor-Owned Electric Utilities' share of St. Lawrence/FDR project, is responsible to deliver and distribute the capacity and associated energy as Basic Generation Service to residential customers as designated by the BPU. In addition, the Company is responsible to distribute to each of the Investor-Owned Electric Utilities the Net Economic Benefits calculated according to the Rate Schedule attached to the Administration Agreement. Each of the Investor-Owned Electric Utilities shall allocate the Net Economic Benefits distributed to it to its residential customers through the Investor-Owned Electric Utility's applicable clause through which it recovers non-utility generation costs, or other appropriate rate mechanism if no such clause exists, in a manner that ensures that such benefits flow exclusively to residential customers.

The Company, in its role as Nominal Recipient of the St. Lawrence/FDR project, advises the Investor-Owned Electric Utilities of their respective allocation of the Net Economic Benefits for the period started January 1, 2019 through January 31, 2020. JCP&L's share of the Net Economic Benefits totaled $137,272.61.

Effective June 1, 2020 through May 31, 2021, a St. Lawrence Hydroelectric Power **credit** of **$0.000015** per KWH **($0.000016** per KWH including SUT) will be combined with the Secondary Voltages Adjusted NGC Charge applicable to Service Classifications RS, RT and RGT. Such combined NGC Charge shall be applied to all KWH usage of any Full Service or Delivery Service residential customers.

Effective February 1, 2020, St. Lawrence Allocation shall be exclusively assigned to the municipally owned utilities and rural electric cooperative in New Jersey. The Company ceases to receive any Net Economic Benefits of St. Lawrence Project's allocation.

JERSEY CENTRAL POWER & LIGHT COMPANY

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Rider SBC
Societal Benefits Charge

APPLICABILITY: Rider SBC provides a charge applicable to all KWH usage of any Full Service Customer or Delivery Service Customer. The charges that may be included in calculating the SBC include nuclear plant decommissioning costs (Rider NDC), demand side management costs (Rider DSF), manufactured gas plant remediation costs (Rider RAC), uncollectible costs (Rider UNC), and universal service fund costs (Rider USF), in accordance with the New Jersey Electric Discount and Energy Competition Act. The current SBC includes the following charges per KWH:

		Including SUT
Rider DSF	**$0.003280**	**$0.003497**
Rider NDC	**$0.000000**	**$0.000000**
Rider RAC	**$0.000806**	**$0.000859**
Rider UNC	**$0.000352**	**$0.000375**
Rider USF	**$0.003940**	**$0.004201**

Carrying costs on unamortized balances of demand side management costs, nuclear decommissioning costs, manufactured gas plant remediation costs, uncollectible costs and universal service fund costs shall be calculated in accordance with the terms of Rider DSF, Rider NDC, Rider RAC, Rider UNC and Rider USF, respectively.

Effective October 1, 2022, the SBC shall be applied to all KWH usage for billing purposes as follows:

		Including SUT
Total SBC:	**$0.008378**	**$0.008932**

Beginning January 1, 2011, with the exception of universal service fund costs component, all over- and under-recoveries of individual SBC components are to be applied to under- or over-recoveries of other SBC components as of each December 31.

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Rider DSF
Demand Side Factor

APPLICABILITY: Rider DSF provides a charge for costs associated with New Jersey Clean Energy Program. The DSF is included in the Societal Benefits Charge applicable to all KWH usage of any Full Service Customer or Delivery Service Customer.

DSF = $0.003280 per KWH ($0.003497 per KWH including SUT)

Demand Side Factor costs include carrying costs on any unamortized balances of such costs at the applicable interest approved by the BPU in its Final Order dated May 17, 2004 (Dockets Nos. ER02080506, et al.), such interest rate shall be the rate actually incurred on the Company's short-term debt (debt maturing in one year or less), or the rate on equivalent temporary cash investments if the Company has no short-term debt outstanding. Interest shall be computed monthly based on the beginning and ending average monthly balance net of deferred income taxes, compounded annually (added to the balance on which interest is accrued annually) on January 1 of each year.

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Rider NDC
Nuclear Decommissioning Costs

APPLICABILITY: Rider NDC provides a charge for Nuclear Decommissioning costs. The NDC is included in the Societal Benefits Charge applicable to all KWH usage of any Full Service Customer or Delivery Service Customer.

NDC = $0.000000 per KWH ($0.000000 per KWH including SUT)

Nuclear Decommissioning costs include carrying costs on any unamortized balances of such costs at the applicable interest rate approved by the BPU in its Final Order dated May 17, 2004 (Docket Nos. ER02080506, et al.). Such interest rate shall be the rate actually incurred on the Company's short-term debt (debt maturing in one year or less), or the rate on equivalent temporary cash investments if the Company has no short-term debt outstanding. Interest shall be computed monthly based on the beginning and ending average monthly balance net of deferred income taxes, compounded annually (added to the balance on which interest is accrued annually) on January 1 of each year.

BPU No. 14 ELECTRIC - PART III **Original Sheet No. 53**

Rider RAC
Remediation Adjustment Clause

APPLICABILITY: Rider RAC determines a Remediation Adjustment in accordance with the formula set forth below. The factor is included in the Societal Benefits Charge applicable to all KWH usage of any Full Service Customer or Delivery Service Customer.

The calculated RAC rate shall be prepared by the Company and filed with the BPU annually by the end of December with a requested effective date of June 1 of the subsequent year. Rider RAC provides for the recovery of manufactured gas plant remediation costs (net of insurance and other recoveries) over rolling seven year periods, including carrying costs on the unamortized balance. Carrying cost is calculated on a monthly basis at an interest rate equal to the rate on seven-year constant maturity Treasuries, as shown in the Federal Reserve Statistical Release on or closest to January 1 of each year, plus sixty basis points, compounded annually as of January 1 of each year.

CALCULATION OF THE REMEDIATION ADJUSTMENT CLAUSE FACTOR:

1) By using the following formula:

   RAC = Recoverable Cost / Sales

2) Where the terms are defined as follows:

   RAC = The Remediation Adjustment Clause factor in cents per KWH to be applied to all applicable retail KWH sales.

   Recoverable Cost = Manufactured Gas Plant remediation expenses (net of insurance and other recoveries) amortized over rolling seven year periods. The cost includes carrying costs on any unamortized balance of remediation costs, net of associated deferred tax balance, at an annual interest rate stated above.

   Sales = The Company's forecasted retail KWH sales.

3) Effective September 1, 2022, the RAC computation is as follows ($ Millions):

   RAC = $15.454 / 19,185,264 MWH = $0.000806 per KWH
   ($0.000859 per KWH including SUT)

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Rider UNC
Uncollectible Accounts Charge

APPLICABILITY: Rider UNC provides a charge for costs associated with uncollectible accounts recorded in FERC account 904 (Uncollectible Accounts). The UNC is included in the Societal Benefits Charge applicable to all KWH usage of any Full Service Customer or Delivery Service Customer.

UNC = $0.000352 per KWH ($0.000375 per KWH including SUT)

Uncollectible costs include carrying costs on any unamortized balances of such costs at the applicable interest rate approved by the BPU in its Final Order dated May 17, 2004 (Docket Nos. ER02080506, et al.). Such interest rate shall be the rate actually incurred on the Company's short-term debt (debt maturing in one year or less), or the rate on equivalent temporary cash investments if the Company has no short-term debt outstanding. Interest shall be computed monthly based on the beginning and ending average monthly balance net of deferred income taxes, compounded annually (added to the balance on which interest is accrued annually) on January 1 of each year.

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BPU No. 14 ELECTRIC - PART III Original Sheet No. 55

Rider USF
Universal Service Fund Costs Recovery

APPLICABILITY: Rider USF provides a charge for costs associated with the state-mandated Universal Service Fund ("USF") to assist certain customers as defined by the BPU. The USF is included in the Societal Benefits Charge and is applicable to all KWH usage of any Full Service Customer or Delivery Service Customer.

Effective October 1, 2022, the USF provided below consists of an USF rate of $0.003205 per KWH and a Lifeline rate of $0.000735 per KWH ($0.003417 per KWH and $0.000784 per KWH including SUT, respectively), pursuant to the BPU Order dated September 28, 2022 (Docket No. ER22060374).

USF = $0.003940 per KWH ($0.004201 per KWH including SUT)

Universal Service Fund costs shall accrue interest on any over or under recovered balances of such costs at the interest rate based on a two-year constant maturity Treasuries as published in the Federal Reserve Statistical Release on the first day of each month (or the closest day thereafter on which rates are published), plus sixty basis points, but shall not exceed the Company's overall rate of return as approved by the BPU. Such interest rate shall be reset each month. The interest calculation shall be based on the net of tax beginning and end average monthly balance, consistent with the methodology in the Board's Final Order dated May 17, 2004 (Docket No. ER02080506 et al.), accrue monthly with an annual roll-in at the end of each reconciliation period.

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Rider QFS
Cogeneration and Small Power Production Service

AVAILABILITY: Rider QFS specifies the conditions under which the Company will purchase electricity from a "Qualifying Facility" ("QF") to the extent required to do so by 18 C.F.R. §292.309, applicable orders from the Federal Energy Regulatory Commission ("FERC"), including Order No. 872, 172 FERC ¶ 61, 041, and under Section 210 of the Public Utilities Regulatory Policies Act of 1978. When required as aforesaid, Rider QFS is available to customers taking service under Service Classifications GS, GST, GP and GT. QF installations must conform to, and are responsible for all costs associated with, the Company's General Interconnect Requirements for Customer's Generation, according to any applicable installation specifications. (See Part II, Section 10)

QF INSTALLATIONS WITH MORE THAN 1000 KW GENERATING CAPACITY

Such installations shall negotiate with the Company for specific contract arrangements to determine the price, term and conditions to delivered energy and capacity, where applicable; provided however, that in no event shall payments to the QF installation under this tariff exceed the revenues the Company receives from PJM (or its successor), net of PJM penalties and charges. Such contracts are subject to BPU approval.

QF INSTALLATIONS WITH 1000 KW OR LESS GENERATING CAPACITY

Service Charge: $40.00 monthly

Energy Payment: Based on actual real-time PJM load weighted average Residual Metered Load Aggregate Locational Marginal Price (LMP) for the JCP&L Transmission Zone at the time when the QF installation delivers energy to the Company.

Capacity Payment: Deliveries from a QF installation that qualify as a PJM Capacity Resource may receive capacity payments when the installed capacity of the QF installation exceeds 100 kW and meets the reliability criteria set forth in PJM Manual 18 (See www.pjm.com), as it may change from time to time. The Capacity Payment, if and as applicable, will be equal to the capacity revenues that the Company receives from PJM for selling such capacity into the Reliability Pricing Model (RPM) capacity auction prior to delivery, adjusted for all other PJM penalties and charges assessed to the Company by PJM arising from, among other things, non-performance or unavailability of the QF installation. QF installations requesting capacity payments must execute an agreement with the Company authorizing the Company to offer such capacity into the PJM market, including terms and conditions of such sale, and including any required security. Any losses experienced by the Company resulting from a QF installation's failure to perform shall be recovered under its Non-utility Generation Charge.

Energy Payment and Capacity Payment, if any, net of Service Charge, shall be determined monthly on an after-the-fact basis, and made within 90 days of the QF meter reading date.

METERING COSTS: QF customers shall pay all metering equipment and related costs as required by the Company and/or by PJM.

INTERCONNECTION COSTS: QF customers shall pay interconnection costs (see Part II, Section 4.05) and any line extension costs required to interconnect the QF to the Company's facilities.

Rider QFS
Cogeneration and Small Power Production Service

LIMITATION ON ENERGY PURCHASES: The Company may refuse to purchase energy from a QF when:

(a) The Company's distribution or transmission circuits are loaded to capacity and further energy would cause an overload. Such refusal to purchase may occur on an instantaneous basis.

(b) An emergency occurs on that part of the Company's system interconnected with the QF such that there would be no means of delivering the energy to the remainder of the Company's system. Such refusal to purchase may also occur on an instantaneous basis.

(c) Customer has failed to provide documentation of QF certification with F.E.R.C. as required by the Company.

(d) Customer has an account arrearage.

Rider STB
Standby Service
(Applicable to Service Classifications GS, GST, GP and GT)

AVAILABILITY: Rider STB specifies the conditions under which customers with qualifying cogeneration or small power production facilities may obtain Standby Service under this Rider when such facilities are used to meet the customer's load requirements. The terms of this Rider shall not be available in any month, however, when the customer's Generation Availability (GA) for the current month does not exceed 50%.

STANDBY DEMAND CHARGE: The terms of this Rider: (1) modify the Determination of Demand and waive the Minimum Demand Charge of the applicable service classification; and (2) impose a Standby Demand Charge determined in accordance with the following calculations and definitions:

SDC=>[(DR*BD)+(SR*<MM or AG)] or [SR*CD]

Which means that the Standby Demand Charge is equal to the greater of:
(1) DR times BD, plus SR times lesser of MM or AG; or
(2) SR times CD

DEFINITIONS:

BD = Billing Demand KW
= >[MM - AG] or [0]
Which means that the Billing Demand is equal to MM - AG, but not less than zero

MM = Maximum Monthly facility on-peak KW load
Which is the maximum coincident 15-minute on-peak load supplied by the Customer's generation plus (or minus) the load delivered by (or furnished to) the Company.

AG = Annual Average Generation on-peak
= Current and preceding eleven months average of [on-peak KWH produced / (260 hours - SM)]
Which means taking the average of each monthly on-peak Average Generation from the current and preceding eleven months. Average Generation is calculated by taking the monthly on-peak KWH produced / (260 hours – SM)

DR = Demand Rate per KW of applicable service classification

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Rider STB
Standby Service
(Applicable to Service Classifications GS, GST, GP and GT)

SR = Standby Rate per KW (including SUT)
= **$4.73** for Service Classifications GS & GST
= **$3.06** for Service Classifications GP
= **$1.47** for Service Classifications GT

CR = Capacity Rating of generation facility

CD = Contract Demand
= <[CR] or [>(estimated MM) or (>MM most recent 12 months)]
Which means that the Contract Demand is equal to the lesser of:
(1) CR; or
(2) the greater of: (a) estimated MM; or (b) highest MM of most recent 12 months

GA = Generation Availability
= AG / CD

SM = Scheduled maintenance hours
Applicable only for customers receiving service under this rider as of February 25, 1993. The number of such hours may be reduced up to the amount of mutually agreed upon scheduled maintenance hours, but are not to exceed the amount actually incurred. A maximum of two 2-week periods may be allowed per year during the billing months of April, May, June, October, November or December and must be scheduled 6-months in advance. Each maintenance period may occur only during a single billing period.

260 hours = Average monthly on-peak hours
= 52 weeks x 5 days x 12 on-peak hours ÷12 months

Rider CEP
Consumer Electronics Protection Service

RESTRICTION: This Rider is closed to new enrollment as of March 3, 1999.

AVAILABILITY: Rider CEP had been available for customers which desire that the Company provide protection from power fluctuations, surges and other power disturbances. Service under this Rider is restricted to service entrance and equipment compatibility.

A single meter socket surge suppression device is necessary on the service entrance supplying power to the premises to protect internal wiring against major power line spikes and surges. Electrical receptacle outlet surge suppressors are available for receptacles within the customer's premise. Such receptacle outlet suppressors provide protection against surges to more sensitive electronics, and are only available when a meter socket surge suppression device is installed. Uninterruptible power supply units are available for use with individual electronic equipment.

MONTHLY CHARGES:	Including SUT	Excluding SUT
Meter socket surge suppression device - single phase:	**$2.93**	**$2.75**
Meter socket surge suppression device - three phase:	**$5.33**	**$5.00**
Electrical receptacle outlet surge suppressor - 2 outlet:	**$0.64**	**$0.60**
Electrical receptacle outlet surge suppressor - 4 outlet:	**$0.80**	**$0.75**
Uninterruptible power supply unit - 0.75 KVA:	**$21.33**	**$20.00**
Uninterruptible power supply unit - 1.00 KVA:	**$26.66**	**$25.00**
Uninterruptible power supply unit - 1.50 KVA:	**$31.99**	**$30.00**

TERM OF CONTRACT:
A one-year term of contract is required, renewable thereafter on a month-to-month basis.

TERMS OF PAYMENT:
Charges applicable under this Rider will be rendered on the customer's bill for electric service. Such bills are due when rendered and become overdue when payment is not received by the Company on or before the due date specified on the bill. Overdue bills thereafter may become subject to a late payment charge as described in Section 3.19, Part II.

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 14 ELECTRIC - PART III Original Sheet No. 61

Rider CEP
Consumer Electronics Protection Service

TERMS AND CONDITIONS:

1) The Company will install and remove the meter socket surge suppressor device and deliver the electrical receptacle outlet surge suppressors and/or Uninterruptible power supply equipment to the customer.

2) Customers utilizing CEP service provided under this Rider shall contact the Company in order to arrange the return of such equipment to the Company, upon termination of this Service, in the manner specified by the Company. Customers failing to arrange to return such equipment to the Company, shall be required to pay a charge equivalent to the Company's current replacement cost for such equipment.

3) The Company shall not be liable for any damage or injury arising from the improper use of equipment supplied under this Rider or for any costs or damages attributable to the loss of the customer's business, production or facilities resulting from the failure of such equipment.

4) The Company will provide the applicable manufacturer's warranty associated with the meter socket surge suppressor device and/or electrical receptacle outlet surge suppressor.

5) Disconnection and subsequent reconnection of Consumer Electronics Protection Service at the same location shall be unavailable as of March 3, 1999. However, if a customer transfers service from one location to another location within the Company's service areas, the customer may transfer the CEP service to the new location.

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 14 ELECTRIC - PART III Original Sheet No. 62

Rider CBT
Corporation Business Tax

APPLICABILITY: In accordance with P.L. 1997, c. 162 (the "energy tax reform statute"), provision for the New Jersey Corporation Business Tax (CBT) as it applies to non-production related revenues has been included in all rate schedules. The energy tax reform statute exempts the following customers from the CBT provision, and when billed to such customers, the rates otherwise applicable under this tariff shall be reduced by the provision for the CBT (and related New Jersey Sales and Use Tax) included therein:

1. Franchised providers of utility services (gas, electricity, water, waste water and telecommunications services provided by local exchange carriers) within the State of New Jersey.

2. Cogenerators in operation, or which have filed an application for an operating permit or a construction permit and a certificate of operation in order to comply with air quality standards under P.L 1954, c. 212 (C.26:2C-1 et seq.) with the New Jersey Department of Environmental Protection, on or before March 10, 1997.

3. Special contract customers for whom a customer-specific tax classification was approved by a written Order of the New Jersey Board of Public Utilities prior to January 1, 1998.

Issued: **Effective:**

Filed pursuant to Order of Board of Public Utilities
Docket No. dated

Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 14 ELECTRIC - PART III Original Sheet No. 63

Rider SUT
Sales and Use Tax

APPLICABILITY: In accordance with P.L. 1997, c. 162 (the "energy tax reform statute"), as amended by P.L. 2016, c. 57, provision for the New Jersey Sales and Use Tax ("SUT") has been included in all charges applicable under this tariff by multiplying the charges that would apply before application of the SUT by the factor 1.06625.

A. The energy tax reform statute exempts the following customers from the SUT provision, and when billed to such customers, the charges otherwise applicable under this tariff shall be reduced by the provision for the SUT included therein:

1. Franchised providers of utility services (gas, electricity, water, waste water and telecommunications services provided by local exchange carriers) within the State of New Jersey.
2. Cogenerators in operation, or which have filed an application for an operating permit or a construction permit and a certificate of operation in order to comply with air quality standards under P.L 1954, c. 212 (C.26:2C-1 et seq.) with the New Jersey Department of Environmental Protection, on or before March 10, 1997.
3. Special contract customers for which a customer-specific tax classification was approved by a written Order of the New Jersey Board of Public Utilities prior to January 1, 1998.
4. Agencies or instrumentalities of the federal government.
5. International organizations of which the United States of America is a member.

B. The Business Retention and Relocation Assistance Act (P.L. 2004, c. 65) and subsequent amendment (P.L. 2005, c. 374) exempts the following customers from the SUT provision, and when billed to such customers, the charges otherwise applicable shall be reduced by the provision for the SUT included therein:

1. A qualified business that employs at least 250 people within an enterprise zone, at least 50% of whom are directly employed in a manufacturing process, for the exclusive use or consumption of such business within an enterprise zone, and
2. A group of two or more persons: (a) each of which is a qualified business that are all located within a single redevelopment area adopted pursuant to the “Local Redevelopment and Housing Law,” P.L.1992, c.79 (C.40A:12A-1 et seq.); (b) that collectively employ at least 250 people within an enterprise zone, at least 50% of whom are directly employed in a manufacturing process; (c) are each engaged in a vertically integrated business, evidenced by the manufacture and distribution of a product or family of products that, when taken together, are primarily used, packaged and sold as a single product; and (d) collectively use the energy and utility service for the exclusive use or consumption of each of the persons that comprise a group within an enterprise zone.
3. A business facility located within a county that is designated for the 50% tax exemption under section 1 of P.L. 1993, c. 373 (C.54:32B-8.45) provided that the business certifies that it employs at least 50 people at that facility, at least 50% of whom are directly employed in a manufacturing process, and provided that the energy and utility services are consumed exclusively at that facility.

A business that meets the requirements in B.1., B.2. or B.3. above shall not be provided the exemption described in this section until it has complied with such requirements for obtaining the exemption as may be provided pursuant to P.L.1983, c.303 (C.52:27H-60 et seq.) and P.L.1966, c.30 (C.54:32B-1 et seq.) and the Company has received a sales tax exemption letter issued by the New Jersey Department of Treasury, Division of Taxation.

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300 Madison Avenue, Morristown, NJ 07962-1911

Rider RRC
RGGI Recovery Charge

APPLICABILITY: Rider RRC provides a charge for the costs associated with demand response/energy efficiency/renewable energy programs directed by the BPU as detailed below. The RGGI Recovery Charge (RRC) is applicable to all KWH usage of any Full Service Customer or Delivery Service Customer, as follows

For service rendered effective January 1, 2023:

RRC = $0.001451 per KWH ($0.001547 per KWH including SUT)

The above RRC provides recovery for the followings:

Solar Renewable Energy Certificates Financing Program (SREC I & II)

Pursuant to BPU Orders dated March 27, 2009 and September 16, 2009 (Docket No. EO08090840) approving an SREC-based financing program (SREC I), pursuant to BPU Order dated December 18, 2013 (Docket No. EO12080750) approving the SREC II, and pursuant to BPU Order dated December 20, 2019 (Docket No. ER19070806) approving the Stipulation of Settlement, the Company shall include an SREC I & II Rate of **$(0.000152)** per kWh (**$(0.000162)** per kWh including SUT) in RRC effective January 1, 2023.

Transition Renewable Energy Certificate Incentive Program (TREC Program)

On December 6, 2019, the Board issued an Order in Docket No. QO19010068 ("December 6, 2019 Order"), establishing a transition renewable energy certificate ("TREC") program to be implemented upon the attainment of 5.1% of the retail electric sales in the State being from solar. Solar projects that become operational after the State's attainment of the 5.1% milestone but prior to the implementation of a successor solar program will be eligible to participate in the TREC Program, as determined by the Board. The December 6, 2019 Order required the New Jersey Electric Distribution Companies ("EDCs") to purchase all TRECs generated and authorized the EDCs to recover their reasonable and prudent costs incurred for the purchase of TRECs and the fees charged by a TREC Administrator (generally, "TREC Program Costs"). The December 6, 2019 Order further provided that "[r]ecovery shall be based on each EDC's proportionate share of retail electric sales."

The TREC Rate recovers JCP&L's proportional share of TREC Program Costs, including, but not limited to, those costs associated with the purchase of TRECs, fees charged by the TREC Administrator, and any additional costs or expenses incurred by JCP&L as a result of the Company's participation in or implementation of the TREC program.

The TREC Rate for all customer classes is **$0.001068** per kWh (**$0.001139** per kWh including SUT), effective January 1, 2023.

Solar Successor Incentive Program (SuSI Program)

On July 28, 2021, the Board issued an order establishing the Solar Successor Incentive ("SuSI") program ("SuSI Order") pursuant to the New Jersey Clean Energy Act and the Solar Act of 2021. The SuSI Order established a new renewable energy certificate, SREC-IIs, and required that the New Jersey Electric Distribution Companies ("EDCs") purchase all SREC-IIs generated and authorized the EDCs to recover their reasonable and prudent costs for SREC-II procurement and SREC-II Administrator fees (generally, "SuSI Program Costs"). The SuSI Order further provided that "[r]ecovery shall be based on each EDC's proportionate share of retail electric sales."

The SuSI Rate recovers JCP&L's proportional share of SuSI Program Costs, including, but not limited to, those costs associated with the purchase of SREC-IIs, fees charged by the SREC-II Administrator, and any additional costs or expenses incurred by JCP&L as a result of the Company's participation in or implementation of the SuSI program.

The SuSI Rate for all customer classes is **$0.000079**/kWh (**$0.000084**/kWh including SUT), effective January 1, 2023.

JERSEY CENTRAL POWER & LIGHT COMPANY

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Rider RRC
RGGI Recovery Charge

Energy Efficiency and Conservation Program (EE&C)

Pursuant to the BPU Order dated June 10, 2020 directing New Jersey's electric and natural gas companies to establish programs that reduce the use of electricity and natural gas within their territories and the BPU Order dated April 27, 2021 approving the Stipulation of Settlement, the Company shall include a EE&C Charge in RRC effective July 1, 2021. The EE&C Charge provides for recovery of revenue requirements associated with Energy Efficiency and Peak Demand Reduction Programs as approved by the BPU.

Effective January 1, 2023, EE&C rate for service classification is as follows:

EE&C = $0.000456 per KWH ($0.000486 per KWH including SUT)

The Company will submit to the BPU annually an application to recover the revenue requirements for the forthcoming Program Year starting July 1st of each year and ending June 30th of the following year. Pursuant to the BPU Order at Docket Nos. QO1901040, QO19060748 & QO17091004, the revenue requirements will include a return of and on EE&C program investments and a reconciliation of actual revenues with actual costs on an annual basis.

The RRC costs shall accrue interest on any over or under recovered balances of such costs at the interest rate based on a two-year constant maturity Treasuries as published in the Federal Reserve Statistical Release on the first day of each month (or the closest day thereafter on which rates are published), plus sixty basis points, but shall not exceed the Company's overall rate of return as approved by the BPU. Such interest rate shall be reset each month. The interest calculation shall be based on the net of tax beginning and end average monthly balance, consistent with the methodology in the Board's Final Order dated May 17, 2004 (Docket No. ER02080506 et al.), compounded annually (added to the balance on which interest is accrued annually) on January 1 of each year.

The Company will make annual filings to true-up the RRC on or before February 1 of each calendar year and will request rate changes, if any, to be implemented on July 1 of the filing year.

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Rider ZEC
Zero Emission Certificate Recovery Charge

APPLICABILITY: The Zero Emission Certificate Recovery Chare ("Rider ZEC" or "ZEC Charge") provides a charge for the recovery of costs associated with the Zero Emission Certificate Program directed by the Board of Public Utilities ("BPU" or "Board") as detailed below. The ZEC Charge is applicable to all kWh usage of any Full Service Customer or Delivery Service Customer.

Per KWH		Including SUT
ZEC Charge	$0.004000	$0.004265
ZEC Reconciliation Charge	($0.000089)	($0.000095)
Total ZEC Charge	**$0.003911**	**$0.004170**

Pursuant to the BPU's Zero Emission Certificate Charge Order dated November 19, 2018 in Docket No. EO18091002, the Board approved the implementation of a non-bypassable, irrevocable ZEC Charge of $0.004000 per KWH for all customers. The ZEC Charge reflects the emission avoidance benefits of the continued operation of selected nuclear plants as determined in L. 2018, c.16 (the "ZEC Law"). The ZEC Charge has been set at the rate specified in the ZEC Law and may be adjusted periodically by the Board, in accordance with the methodology provided for in the ZEC law.

In accordance with the ZEC Law, the proceeds of the ZEC Charge will be placed in a separate account, which amount the Company may use for general corporate purposes, with interest applied at the Company's short-term borrowing rate as calculated each month, and will be used solely to purchase ZECs and to reimburse the Board for its reasonable, verifiable costs incurred to implement the ZEC program. Refunds will be provided to the customers served under each of the Company's rate schedules in proportion to the ZEC Charge revenues contributed by the rate schedule.

JERSEY CENTRAL POWER & LIGHT COMPANY

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Rider TAA
Tax Act Adjustment

APPLICABILITY: Rider TAA provides a credit resulting from the amortization and reconciliation of certain Excess Deferred Income Taxes ("EDIT"), including applicable carrying charges related to the impact of the Federal Tax Cuts and Jobs Act of 2017 ("Tax Act") on the Company's rates.

Effective **May 15, 2019**, the following TAA credits, including one time bill credit, (including Sales and Use Tax as provided in Rider SUT) will be applicable to all KWH usage of any Full Service Customer or Delivery Service Customer under Service Classification:

RS	**$0.006389 per KWH**
RT/RGT	**$0.006103 per KWH**
GS	**$0.005116 per KWH**
GST	**$0.003950 per KWH**
GP	**$0.002782 per KWH**
GT	**$0.001632 per KWH**
Lighting	**$0.027344 per KWH**

(includes OL, SVL, MVL, ISL and LED)

Effective **June 15, 2019**, the following TAA credits (including Sales and Use Tax as provided in Rider SUT) will be applicable to all KWH usage of any Full Service Customer or Delivery Service Customer under Service Classification:

RS	**$0.000310 per KWH**
RT/RGT	**$0.000307 per KWH**
GS	**$0.000274 per KWH**
GST	**$0.000213 per KWH**
GP	**$0.000154 per KWH**
GT	**$0.000093 per KWH**
Lighting	**$0.001567 per KWH**

(includes OL, SVL, MVL, ISL and LED)

Carrying Charges: Interest should not accrue on the outstanding net unprotected EDIT liability. No interest charges apply to over or under-recovered balances.

Rider RP
JCP&L Reliability Plus Charge

APPLICABILITY: Rider RP provides for full and timely recovery of revenue requirements associated with reliability infrastructure investment projects subject to the Infrastructure Investment and Recovery regulations pursuant to N.J.A.C. 14:3-2A.1 *et seq.* and as approved by the BPU Order dated May 8, 2019 in Docket No. EO18070728.

The JCP&L Reliability Plus (RP) Charge is applicable to Service Classifications RS (Residential Service), RT (Residential Time-of-Day), RGT (Residential Geothermal & Heat Pump), GS (General Service Secondary), GST (General Service Secondary Time-of-Day), GP (General Service Primary), GT (General Service Transmission), OL (Outdoor Lighting), SVL (Sodium Vapor Street Lighting), MVL (Mercury Vapor Street Lighting), ISL (Incandescent Street Lighting) and LED (LED Street Lighting) and for all usage (KWH, KW or per Fixture) of any Full Service Customer or Delivery Service Customer, as follows:

Service Classification	RP Charge (Including SUT)	
RS	$0.000000	per KWH
RT/RGT	$0.000000	per KWH
GS	$0.000000	per KWH
GST	$0.00	per KW
GP	$0.00	per KW
GT	$0.00	per KW
Lighting (OL, SVL, MVL, SVL and LED)	$0.00	per Fixture

The Company will make periodic filings to reset the RP Charges. The initial recovery period will include actual capital investments with in-service dates between June 1, 2019 and November 30, 2019 and will be filed no later than September 15, 2019 with an effective date on or before March 1, 2020. All subsequent filings will adhere to the Company's recovery periods as approved in the above referenced BPU Order and in accordance with N.J.A.C. 14:3-2A.1 *et seq.*

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Rider LRAM
JCP&L Lost Revenue Adjustment Mechanism Charge

APPLICABILITY: The Lost Revenue Adjustment Mechanism Charge ("Rider LRAM" or "LRAM Charge") provides for recovery of the revenue impact of sales losses demonstrated to have resulted from the Company's Energy Efficiency and Peak Demand Reduction Programs, subject to regulations pursuant to N.J.S.A. 48:3-98. 1(a)(1) and as approved by the BPU Order.

The JCP&L LRAM Charge is applicable to Service Classifications RS (Residential Service), RT (Residential Time-of-Day), RGT (Residential Geothermal & Heat Pump), GS (General Service Secondary), GST (General Service Secondary Time-of-Day), GP (General Service Primary), GT (General Service Transmission), OL (Outdoor Lighting), SVL (Sodium Vapor Street Lighting), MVL (Mercury Vapor Street Lighting), ISL (Incandescent Street Lighting) and LED (LED Street Lighting) and for all usage (KWH and KW) of any Full Service Customer or Delivery Service Customer, as follows:

LRAM Charge effective July 1, 2021

Service Classification	LRAM Charge (Including SUT)	
RS	$0.000000	per KWH
RT/RGT	$0.000000	per KWH
GS	$0.000000	per KWH
GST	$0.00	per KW
GP	$0.00	per KW
GT	$0.00	per KW
Lighting (OL, SVL, MVL, SVL and LED)	$0.000000	per KWH

The Company will submit to the BPU by August 31st of each year, starting August 31, 2022, to recover the lost distribution revenue the Company's Energy Efficiency and Peak Demand Reduction Programs for the preceding year ended June 30th. The lost distribution revenue in each filing will be considered verified once the underlying energy savings have been verified through the Evaluation Measurement & Verification process undertaken by the Company's independent evaluator, subject to BPU review. Within each rate filing, there will be a reconciliation of actual revenues received with projected revenues, including carrying costs, through the end of February of each year. Any adjustment of the amount of savings used to determine lost revenue recovery resulting from the verification process, but not completed by the time of filing, will be included in the following year's reconciliation. The applicable carrying cost is calculated on a monthly basis at an interest rate equal to the rate on two-year constant maturity Treasuries, as show in the Federal Reserve Statistical Release on or closest to January 1 of each year, plus sixty basis points, compounded annually as of January 1 of each year. All subsequent filings will adhere to the Company's recovery periods as approved in the above referenced BPU Order.

Rider EV
ELECTRIC VEHICLE CHARGER RIDER

The EV Driven Program ("Program") is comprised of four (4) subprograms to incentivize EV adoption throughout the JCP&L service territory, and thereby to support the attainment of the State's goals for EV adoption and the reduction of greenhouse gas ("GHG") emissions. These subprograms include: 1) Residential Customer Sub-program; 2) Mixed-Use Commercial Sub-program; 3) Direct Current ("DC") Fast Charger ("DCFC") Public Charging Subprogram; and 4) Consumer Education and Outreach initiative. All Program incentives and Program initiatives contained within this rider are subject to the Terms established by JCP&L, available at http://www.jcp-l.com/evdriven, and are subject to modification by the Company.

The Program will commence on July 15, 2022 and will terminate on July 15, 2026, or earlier if the budgeted funds for the Program, or any individual subprogram, are exhausted. The Company does reserve the right to extend the Program with BPU approval.

1) Electric Vehicle Charger Off-Peak Credit

APPLICABILITY: Available to new and existing Residential and Multi-Family Customers being served on Service Classification RS, RT, RGT, GS who install a Company-qualified smart Electric Vehicle ("EV") Level 2 ("L2") charger ("Eligible Customer"). This provision within Rider EV is voluntary and offers qualified customers the opportunity to receive a bill credit by charging an EV battery with a Company-qualified smart EV L2 charger during Off-Peak hours. Customers must agree to share and communicate the charging data from their smart EV L2 charger via remote access with the Company to receive the bill credit. Customers are not required to receive their generation supply through Basic Generation Service to be eligible for this Rider. This Rider is limited to 2,000 eligible residential and 75 eligible multi-family Customers on a first-come, first-serve basis. Only customers whose application is accepted by the Company will receive the Off-Peak Credit.

RATE: Eligible Customers that qualify for this provision within this Rider will receive a credit of 2 cents per Kilowatt-hour ("kWh") for Net Off-Peak kWh Usage at their smart EV L2 charger. Net Off-Peak kWh Usage is calculated as kWh usage recorded by the Customer's smart EV Level 2 charger during Off-Peak hours less kWh usage recorded by the Customer's smart EV L2 charger during On-Peak hours. Net Off-Peak kWh Usage must be a positive value for the Customer to receive a credit. In the event Off-Peak kWh less On-Peak kWh is less than zero, the Net Off-Peak kWh Usage shall be considered zero for the measurement period. JCP&L will provide the on-bill credits[1] to residential customers on a quarterly basis, which bill credits will terminate when the budget has been exhausted or the Program has terminated. Quarterly off-peak bill credits for eligible non-residential customers will be paid via off-bill credit.

On-Peak hours are Monday through Friday from 6:00 AM to 11:00 PM, Eastern Standard Time. All other hours including weekend hours will be considered off-peak. The Company reserves the right to change the on-peak hours from time to time as the on-peak periods of the supply system change. The Company may also selectively stagger the on-peak hours up to one hour in either direction when required to alleviate local distribution system peaking within high-density areas. The off-peak hours will not, however, be less than 7 hours daily.

TERM: Month to month basis. This provision within this Rider will be available until the earlier of the Company modifying the Off-Peak Credit program or July 15, 2026.

[1] Customer credits will accrue until such time as on-bill credit functionality is fully deployed by the Company. Payment of a customer's accrued credits will occur after full deployment of on-bill credit functionality by the Company.

Rider EV (CONT.)
ELECTRIC VEHICLE CHARGER RIDER

2) Customer Make-Ready Incentive:

APPLICABILITY: Provides incentives for the Make-Ready Work on the customer-side of the meter necessary to enable the installation of a Company-qualified EV Charger. The available make-ready incentives do not include the cost of the charger. Available to all Eligible Customers located in the territory served by the Company. Eligible Customers must install a Company-qualified EV L2 charger or Direct Current Fast Charger ("DCFC"), subject to the limitations outlined below and the Program Terms established by the Company and available at www.jcp-l.com/evdriven.

The Company will provide an incentive to Customers served under Schedule RS, RT, RGT, GS, GST, GP, and GT who install a Company-qualified smart EV Level 2 charger or DCFC after the commencement date of the Program. The smart EV L2 charger or DCFC must be connected after the Company meter and must be owned by the Customer receiving the incentive. The smart EV L2 charger for other than residential and multi-family applications and DCFC applications must be publicly-accessible charging ports. In accordance with Board's Order approving the Program in BPU Docket No. EO21030630, "publicly-accessible charging" means a charger located on public land, a community location, or travel corridor. Such chargers are owned and operated by site owner, property manager or management company, EVSE Infrastructure Company, or, in limited cases, an EDC, that is accessible to the public 24 hours a day, seven days a week; however, generic parking restrictions or requirements, such as in a commercial garage, or emergency restrictions, including construction, street cleaning, etc., are not applicable. Such chargers may charge the EV owner a fee for charging; such fees will be clearly displayed to the user. Customers are not required to receive their generation supply through Basic Generation Service to be eligible for the incentive. A list of qualifying smart EV L2 chargers is available on the Company's website at www.jcp-l.com/evdriven.

In order to qualify for the Company incentive, the Customer must submit an application with all necessary supporting documentation within 30 days of installation (including copies of receipts and/or invoices of the smart EV L2 charger or DCFC purchase and installation costs) and agree to share and communicate the charging data from the smart EV L2 charger or DCFC with the Company. The Customer is responsible for maintenance and enabling the smart capabilities of the EV L2 charger or DCFC. Once the Company receives the Customer's completed application and confirms that the Customer's smart EV L2 charger or DCFC has been installed and is available for service and capable of remote communication, and approves the application, the Company shall issue the applicable incentive. The program only applies to eligible smart EV L2 chargers and DCFCs installed on or after July 15, 2022. Customer Make-Ready Incentives will be paid in an amount, not to exceed the amount stated in the table below for new service to EV chargers for each subprogram, based on the actual documented cost of the make-ready work, excluding the cost of the charger:

Sub-Program	Customer Make-Ready Incentive (up to $ amount)
Residential Customer Sub-program	$1,500
Public/Community based Component	$6,700
Workplace Component	$5,000
Multi-family Component	$6,700
Multi-family in Overburdened Communities	$8,375
DCFC Public Charging Sub-Program	$25,000

Rider EV (CONT.)
ELECTRIC VEHICLE CHARGER RIDER

3) Utility Make-Ready Work:

All applicants must advance the cost of any Utility Make-Ready Work to ensure that: 1) the utility service is adequate to support EV charging; 2) any service upgrade is for the purpose of supporting EV charging; and 3) the customer follows through with the charger installation. The Company will be responsible for any utility upgrades to its facilities necessary to meet the adequate character and capacity of its electric service requirements to the Customer at the Company's reasonable discretion and subject to the BPU's notification and approval requirements. Utility Make-Ready Incentives for new service to EV chargers for each Sub-program will be paid in an amount, not to exceed the amount stated in the table below for each subprogram, based on the actual cost of the Utility Make-Ready Work.

Sub-Program	Amount of Utility Make Ready Incentive (up to $ amount)
Residential Customer Sub-program	$5,500
Public/Community based Component	$11,100
Workplace Component	$11,100
Multi-family Component	$11,100
DCFC Public Charging Sub-Program	$50,500

4) Multifamily EV Charging Residential Parity Rate

AVAILABILITY: Available to new and existing all Company-qualified Level 2 Electric Vehicle Charging Stations located at Multifamily Dwellings ("Multifamily Level 2 Electric Vehicle Charging Station") at a separately metered premise from the metering at the multifamily complex.

RATE: Electric service shall be billed at a rate equivalent to that which would be billed under the Service Classification RS – Residential Service, pursuant to the BPU Order in Docket QO20050357**.**

TERM: Month to month basis. This provision will be available until July 15, 2026, or earlier if the budgeted funds for the Program, or any individual subprogram, are exhausted.

5) DCFC Public Charging Subprogram - Distribution Demand Charge Discount

AVAILABILITY: Available to new and existing customers participating in the DCFC Public Charging Sub-Program of JCP&L's BPU-approved EV Driven Program. Such customers will be eligible for a kW distribution demand charge discount related to the DCFC EV charging ports, which will be separately metered from other electric load at the site, and served on Rate Classification GS, GST, GP, or GT.

RATE: The discount will be provided for the distribution demand charge portion of the bill and will be provided as an off-bill payment on a quarterly basis. The kW distribution demand charge discount will be as follows for each program year:

Program Year	% Discount
1	50%
2	50%
3	25%
4	25%

Program Year is defined as the date of initial implementation for 12 months. All bill credits will be terminated when the EV Driven Budget for Demand Charge discount has been exhausted or the Program has been terminated, whichever comes first.

TERM: Month to month basis. This provision will be available until the budget has been exhausted or the Program has terminated, whichever occurs first.

Exhibit JC-09
Schedule YP - 2 (6+6)

Jersey Central Power & Light Company
Summary of Distribution Revenue Requirement Changes and Classified Revenue Requirements

	TOTAL	RS	RT	GS	GST	GP	GT	LTG
RATE CHANGE REQUESTED								
REVENUE CHANGE	**$184,953,113**	**$100,654,674**	**$1,989,376**	**$61,957,464**	**$3,246,846**	**$8,122,998**	**$6,211,249**	**$2,770,504**
% REVENUE INCREASE / (DECREASE)	28.8%	28.8%	28.8%	29.8%	29.8%	29.8%	29.8%	14.4%
REQUESTED RATE OF RETURN	7.60%	5.61%	9.44%	10.10%	9.09%	15.86%	57.08%	1.89%
PROPOSED UNITIZED RATE OF RETURN		0.74	1.24	1.33	1.20	2.09	7.51	0.25
CUSTOMER								
DISTRIBUTION TARIFF REVENUE	**$107,591,529**	**$83,354,679**	**$1,340,320**	**$12,575,144**	**$79,298**	**$2,719,821**	**$7,400,989**	**$121,279**
DEMAND								
DISTRIBUTION TARIFF REVENUE	**$386,326,513**	**$214,172,340**	**$3,681,013**	**$124,233,990**	**$5,451,415**	**$11,223,203**	**$7,092,206**	**$20,472,345**
ENERGY								
DISTRIBUTION TARIFF REVENUE	**$333,711,684**	**$152,883,352**	**$3,880,745**	**$132,939,603**	**$8,605,320**	**$21,422,667**	**$12,549,175**	**$1,430,822**
TOTAL								
DISTRIBUTION TARIFF REVENUE	**$827,629,725**	**$450,410,371**	**$8,902,078**	**$269,748,737**	**$14,136,032**	**$35,365,691**	**$27,042,370**	**$22,024,446**

Exhibit JC-09
Schedule YP - 3 (6+6)

Jersey Central Power & Light Company
Summary
Proof of Cost of Service Distribution Tariff Revenue to Proposed Distribution Rates

Rate Class		COSS Distribution Tariff Revenue (1) (a)	Proposed Distribution Revenue Charges Customer (b)	kWh Dist. (c)	Demand (d)	Total (e)=(b)+(c)+(d)	Revenue Delta (f)=(e)-(a)	Per kWh Delta
RS	Distribution							
	Customer	$83,354,679	$63,533,269	$19,819,054	$0	$83,352,323		
	Demand	$214,172,340	$0	$214,172,340	$0	$214,172,340		
	Energy	$152,883,352	$0	$152,883,352	$0	$152,883,352		
	Total	$450,410,371	$63,533,269	$386,874,746	$0	$450,408,015	-$2,356	-0.0000003
RT & RGT	Distribution							
	Customer	$1,340,320	$1,449,770	-$109,399	$0	$1,340,371		
	Demand	$3,681,013	$0	$3,681,013	$0	$3,681,013		
	Energy	$3,880,745	$0	$3,880,745	$0	$3,880,745		
	Total	$8,902,078	$1,449,770	$7,452,359	$0	$8,902,129	$51	0.0000003
GS	Distribution							
	Customer	$12,575,144	$16,454,995	-$3,879,851	$0	$12,575,144		
	Demand	$124,233,990	$0	-$18,220,743	$142,454,733	$124,233,990		
	Energy	$132,939,603	$0	$132,941,662	$0	$132,941,662		
	Total	$269,748,737	$16,454,995	$110,841,067	$142,454,733	$269,750,795	$2,058	0.0000003
GST	Distribution							
	Customer	$79,298	$139,236	-$59,938	$0	$79,298		
	Demand	$5,451,415	$0	-$6,415,700	$11,867,115	$5,451,415		
	Energy	$8,605,320	$0	$8,605,113	$0	$8,605,113		
	Total	$14,136,032	$139,236	$2,129,475	$11,867,115	$14,135,826	-$206	-0.0000005
GP	Distribution							
	Customer	$2,719,821	$539,990	$2,179,831	$0	$2,719,821		
	Demand	$11,223,203	$0	-$18,116,225	$29,339,428	$11,223,203		
	Energy	$21,422,667	$0	$21,422,141	$0	$21,422,141		
	Total	$35,365,691	$539,990	$5,485,747	$29,339,428	$35,365,165	-$526	-0.0000003
GT	Distribution							
	Customer	$7,400,989	$671,159	$6,729,830	$0	$7,400,989		
	Demand	$7,092,206	$0	-$15,121,644	$22,213,850	$7,092,206		
	Energy	$12,549,175	$0	$12,549,012	$0	$12,549,012		
	Total	$27,042,370	$671,159	$4,157,198	$22,213,850	$27,042,207	-$163	-0.0000001
Lighting	Distribution		Fixtures	Misc.	kWh			
	Total	$22,024,446	$15,441,909	$449,938	$6,132,558	$22,024,405	-$41	-0.0000004
Total	Customer	$107,470,250	$82,788,419	$24,679,526	$0	$107,467,945		
	Demand	$365,854,168	$0	$159,979,042	$205,875,126	$365,854,168		
	Energy	$332,280,862	$0	$332,282,024	$0	$332,282,024		
	Lighting Total	$22,024,446	$15,441,909	$449,938	$6,132,558	$22,024,405		
	Total	$827,629,725	$98,230,328	$517,390,530	$212,007,684	$827,628,542	-$1,183	-0.0000001

(1) Source: Exhibit JC-08

Jersey Central Power & Light Company

Summary Proof of Revenues

Based on 2022/2023 6+6 Weather Normalized Billing Determinants (Excludes SUT)

Revenue at Proposed Rates Effective TBD

Rate Class	NGC	Distr.	Transmission	SBC	ZEC	RRC	TAA	BGS	Total
RS	-$2,063,542	$450,408,015	$132,255,155	$78,942,269	$36,851,661	$13,672,145	-$2,741,967	$699,862,867	$1,407,186,603
RT/RGT	-$42,816	$8,902,129	$2,744,090	$1,637,930	$764,615	$283,676	-$56,305	$13,661,513	$27,894,832
GS	-$1,422,671	$269,750,795	$91,180,919	$54,425,316	$25,406,709	$9,426,013	-$1,669,528	$454,312,856	$901,410,409
GST	-$96,600	$14,135,826	$6,191,240	$3,695,512	$1,725,131	$640,032	-$88,219	$43,307,793	$69,510,715
GP	-$331,655	$35,365,165	$13,589,882	$13,358,680	$6,236,070	$2,313,612	-$229,607	$148,393,790	$218,695,937
GT	-$348,105	$27,042,207	$12,555,335	$16,054,466	$7,494,511	$2,780,500	-$166,715	$165,970,692	$231,382,891
Lighting	-$24,989	$22,024,405	$0	$955,927	$446,243	$165,557	-$167,726	$6,237,374	$29,636,791
Total	-$4,330,378	$827,628,542	$258,516,621	$169,070,100	$78,924,940	$29,281,535	-$5,120,067	$1,531,746,885	$2,885,718,178

Change in Revenue from Current Rates to Proposed Rates Effective TBD

Rate Class	NGC	Distr.	Transmission	SBC	ZEC	RRC	TAA	BGS	Total
RS	$0	$100,652,318	$0	$0	$0	$0	$0	$0	$100,652,318
RT/RGT	$0	$1,989,428	$0	$0	$0	$0	$0	$0	$1,989,428
GS	$0	$61,959,522	$0	$0	$0	$0	$0	$0	$61,959,522
GST	$0	$3,246,640	$0	$0	$0	$0	$0	$0	$3,246,640
GP	$0	$8,122,472	$0	$0	$0	$0	$0	$0	$8,122,472
GT	$0	$6,211,087	$0	$0	$0	$0	$0	$0	$6,211,087
Lighting	$0	$2,770,463	$0	$0	$0	$0	$0	$0	$2,770,463
Total	$0	$184,951,930	$0	$0	$0	$0	$0	$0	$184,951,930

Percentage Change in Revenue from Current Rates to Proposed Rates Effective TBD

Rate Class	NGC	Distr.	Transmission	SBC	ZEC	RRC	TAA	BGS	Total
RS	0.0%	7.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	7.7%
RT/RGT	0.0%	7.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	7.7%
GS	0.0%	7.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	7.4%
GST	0.0%	4.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	4.9%
GP	0.0%	3.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.9%
GT	0.0%	2.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.8%
Lighting	0.0%	10.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	10.3%
Total	0.0%	6.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	6.8%

Jersey Central Power & Light Company

Based on 2022/2023 6+6 Weather Normalized Billing Determinants (Excludes SUT)

Residential Service (RS)

Description of Charge	Weather Normalized 2022/2023 6+6 Units (a)	Current Rates {1} (b)	Revenue Based on Current Rates (c) = (a) x (b)	Description of Charge	Weather Normalized 2022/2023 6+6 Units (d)	Proposed Rates {2} (e)	Revenue Based on Proposed Rates (f) = (d) x (e)	Change in Revenue (g) = (f) - (c)	Percentage Change in Revenue (h) = (g) / (c)
Customer Charges				Customer Charges					
1 Standard Customer Charge	12,065,452	$3.05	$36,799,628	1 Standard Customer Charge	12,065,452	$5.25	$63,343,623	$26,543,995	72.1%
2 Supplemental OPWH {3}	29,997	$1.59	$47,696	2 Supplemental OPWH {3}	29,997	$2.74	$82,193	$34,497	72.3%
3 Supplemental CTWH {3}	39,216	$1.59	$62,354	3 Supplemental CTWH {3}	39,216	$2.74	$107,453	$45,099	72.3%
4 Total Customer Charges	12,065,452		$36,909,678	4 Total Customer Charges	12,065,452		$63,533,269	$26,623,591	72.1%
NGC per kWh Charges				NGC per kWh Charges					
5 Summer kWh 0 - 600	1,995,135,765	-$0.000219	-$436,935	5 Summer kWh 0 - 600	1,995,135,765	-$0.000219	-$436,935	$0	0.0%
6 Summer kWh > 600	1,920,000,355	-$0.000219	-$420,480	6 Summer kWh > 600	1,920,000,355	-$0.000219	-$420,480	$0	0.0%
7 Winter All kWh	5,500,616,834	-$0.000219	-$1,204,635	7 Winter All kWh	5,500,616,834	-$0.000219	-$1,204,635	$0	0.0%
8 Summer OPWH kWh	814,641	-$0.000219	-$178	8 Summer OPWH kWh	814,641	-$0.000219	-$178	$0	0.0%
9 Winter OPWH kWh	1,971,186	-$0.000219	-$432	9 Winter OPWH kWh	1,971,186	-$0.000219	-$432	$0	0.0%
10 Summer CTWH kWh	1,088,049	-$0.000219	-$238	10 Summer CTWH kWh	1,088,049	-$0.000219	-$238	$0	0.0%
11 Winter CTWH kWh	2,940,494	-$0.000219	-$644	11 Winter CTWH kWh	2,940,494	-$0.000219	-$644	$0	0.0%
12 Total NGC Charges	9,422,567,325		-$2,063,542	12 Total NGC Charges	9,422,567,325		-$2,063,542	$0	0.0%
SBC per kWh Charges				SBC per kWh Charges					
13 All kWh	9,422,567,325	$0.008378	$78,942,269	13 All kWh	9,422,567,325	$0.008378	$78,942,269	$0	0.0%
Distribution per kWh Charges				Distribution per kWh Charges					
14 Summer kWh 1 to 600	1,995,135,765	$0.016813	$33,544,218	14 Summer kWh 1 to 600	1,995,135,765	$0.020792	$41,482,863	$7,938,645	23.7%
15 Summer kWh > 600	1,920,000,355	$0.066487	$127,655,064	15 Summer kWh > 600	1,920,000,355	$0.082220	$157,862,429	$30,207,365	23.7%
16 Winter kWh - All Non WH kWh	5,500,616,834	$0.027542	$151,497,989	16 Winter kWh - All Non WH kWh	5,500,616,834	$0.034059	$187,345,509	$35,847,520	23.7%
17 Summer OPWH kWh	814,641	$0.018382	$14,975	17 Summer OPWH kWh	814,641	$0.022732	$18,518	$3,543	23.7%
18 Winter OPWH kWh	1,971,186	$0.018382	$36,234	18 Winter OPWH kWh	1,971,186	$0.022732	$44,809	$8,575	23.7%
19 Summer CTWH kWh	1,088,049	$0.024212	$26,344	19 Summer CTWH kWh	1,088,049	$0.029941	$32,577	$6,233	23.7%
20 Winter CTWH kWh	2,940,494	$0.024212	$71,195	20 Winter CTWH kWh	2,940,494	$0.029941	$88,041	$16,846	23.7%
21 Total Distribution kWh Charges	9,422,567,325		$312,846,019	21 Total Distribution kWh Charges	9,422,567,325		$386,874,746	$74,028,727	23.7%
BGS per kWh Charges				BGS per kWh Charges					
22 Summer - 0 to 600 kWh	1,995,135,765	$0.067042	$133,757,892	22 Summer - 0 to 600 kWh	1,995,135,765	$0.067042	$133,757,892	$0	0.0%
23 Summer - Over 600 kWh	1,920,000,355	$0.075694	$145,332,507	23 Summer - Over 600 kWh	1,920,000,355	$0.075694	$145,332,507	$0	0.0%
24 Winter-Non-Water Heating kWh	5,500,616,834	$0.076409	$420,296,632	24 Winter-Non-Water Heating kWh	5,500,616,834	$0.076409	$420,296,632	$0	0.0%
25 Summer-OPWH & CTWH kWh	1,902,690	$0.069971	$133,133	25 Summer-OPWH & CTWH kWh	1,902,690	$0.069971	$133,133	$0	0.0%
26 Winter-OPWH & CTWH kWh	4,911,680	$0.069773	$342,703	26 Winter-OPWH & CTWH kWh	4,911,680	$0.069773	$342,703	$0	0.0%
27 Total BGS Charges	9,422,567,325		$699,862,867	27 Total BGS Charges	9,422,567,325		$699,862,867	$0	0.0%
Transmission per kWh Charges				Transmission per kWh Charges					
28 All Non-Water Heating kWh	9,415,752,954	$0.014036	$132,159,508	28 All Non-Water Heating kWh	9,415,752,954	$0.014036	$132,159,508	$0	0.0%
29 OPWH & CTWH kWh	6,814,370	$0.014036	$95,647	29 OPWH & CTWH kWh	6,814,370	$0.014036	$95,647	$0	0.0%
30 Total Transmission Charges	9,422,567,325		$132,255,155	30 Total Transmission Charges	9,422,567,325		$132,255,155	$0	0.0%
ZEC Recovery Charges				ZEC Recovery Charges					
31 All kWh	9,422,567,325	$0.003911	$36,851,661	31 All kWh	9,422,567,325	$0.003911	$36,851,661	$0	0.0%
RGGI Recovery Charge				RGGI Recovery Charge					
32 All kWh	9,422,567,325	$0.001451	$13,672,145	32 All kWh	9,422,567,325	$0.001451	$13,672,145	$0	0.0%
Tax Act djustment				Tax Act djustment					
33 All kWh	9,422,567,325	-$0.000291	-$2,741,967	33 All kWh	9,422,567,325	-$0.000291	-$2,741,967	$0	0.0%
LRAM				LRAM					
34 All kWh	9,422,567,325	$0.000000	$0	34 All kWh	9,422,567,325	$0.000000	$0	$0	#DIV/0!
34 Total Charges	9,422,567,325		$1,306,534,285	34 Total Charges	9,422,567,325		$1,407,186,603	$100,652,318	7.7%
35 Average $/kWh			0.138660117	35 Average $/kWh			0.149342165		

{1} Rates effective 3/1/2023

{2} Proposed rates effective TBD

{3} Units are included with line 1 and therefore are not added into the total on line 4.

Jersey Central Power & Light Company

Based on 2022/2023 6+6 Weather Normalized Billing Determinants (Excludes SUT)

Residential Time-of-Day Service (RT)

Description of Charge	Weather Normalized 2022/2023 6+6 Units (a)	Current Rates {1} (b)	Revenue Based on Current Rates (c) = (a) x (b)	Description of Charge	Weather Normalized 2022/2023 6+6 Units (d)	Proposed Rates {2} (e)	Revenue Based on Proposed Rates (f) = (d) x (e)	Change in Revenue (g) = (f) - (c)	Percentage Change in Revenue (h) = (g) / (c)
Customer Charges				Customer Charges					
1 Standard Customer Charge	165,090	$6.61	$1,091,245	1 Standard Customer Charge	165,090	$8.51	$1,404,916	$313,671	28.7%
2 Solar Water Heating Credit {3}	1,599	-$1.66	-$2,654	2 Solar Water Heating Credit {3}	1,599	-$2.14	-$3,422	-$768	28.9%
3 Total Customer Charges	165,090		$1,088,591	3 Total Customer Charges	165,090		$1,401,494	$312,903	28.7%
NGC per kWh Charges				NGC per kWh Charges					
4 On-Peak kWh - Summer	23,966,990	-$0.000219	-$5,249	4 On-Peak kWh - Summer	23,966,990	-$0.000219	-$5,249	$0	0.0%
5 On-Peak kWh - Winter	44,413,278	-$0.000219	-$9,727	5 On-Peak kWh - Winter	44,413,278	-$0.000219	-$9,727	$0	0.0%
6 Off-Peak kWh - Summer	33,314,847	-$0.000219	-$7,296	6 Off-Peak kWh - Summer	33,314,847	-$0.000219	-$7,296	$0	0.0%
7 Off-Peak kWh - Winter	79,593,848	-$0.000219	-$17,431	7 Off-Peak kWh - Winter	79,593,848	-$0.000219	-$17,431	$0	0.0%
8 Total NGC Charges	181,288,963		-$39,703	8 Total NGC Charges	181,288,963		-$39,703	$0	0.0%
SBC per kWh Charges				SBC per kWh Charges					
9 All kWh	181,288,963	$0.008378	$1,518,839	9 All kWh	181,288,963	$0.008378	$1,518,839	$0	0.0%
Distribution per kWh Charges				Distribution per kWh Charges					
10 On-Peak kWh - Summer	23,966,990	$0.049096	$1,176,683	10 On-Peak kWh - Summer	23,966,990	$0.063353	$1,518,381	$341,698	29.0%
11 On-Peak kWh - Winter	44,413,278	$0.036063	$1,601,676	11 On-Peak kWh - Winter	44,413,278	$0.046535	$2,066,772	$465,096	29.0%
12 Off-Peak kWh - Summer	33,314,847	$0.022934	$764,043	12 Off-Peak kWh - Summer	33,314,847	$0.029594	$985,920	$221,877	29.0%
13 Off-Peak kWh - Winter	79,593,848	$0.022934	$1,825,405	13 Off-Peak kWh - Winter	79,593,848	$0.029594	$2,355,500	$530,095	29.0%
14 Total Distribution kWh Charges	181,288,963		$5,367,807	14 Total Distribution kWh Charges	181,288,963		$6,926,573	$1,558,766	29.0%
BGS per kWh Charges				BGS per kWh Charges					
15 Summer - On Peak kWh	23,966,990	$0.096185	$2,305,265	15 Summer - On Peak kWh	23,966,990	$0.096185	$2,305,265	$0	0.0%
16 Winter - On Peak kWh	44,413,278	$0.097367	$4,324,388	16 Winter - On Peak kWh	44,413,278	$0.097367	$4,324,388	$0	0.0%
17 Summer - Off Peak KWh	33,314,847	$0.050786	$1,691,928	17 Summer - Off Peak KWh	33,314,847	$0.050786	$1,691,928	$0	0.0%
18 Winter - Off Peak kWh	79,593,848	$0.053808	$4,282,786	18 Winter - Off Peak kWh	79,593,848	$0.053808	$4,282,786	$0	0.0%
19 Total BGS Charges	181,288,963		$12,604,367	19 Total BGS Charges	181,288,963		$12,604,367	$0	0.0%
Transmission per kWh Charges				Transmission per kWh Charges					
20 All kWh	181,288,963	$0.014036	$2,544,572	20 All kWh	181,288,963	$0.014036	$2,544,572	$0	0.0%
ZEC Recovery Charges				ZEC Recovery Charges					
21 All kWh	181,288,963	$0.003911	$709,021	21 All kWh	181,288,963	$0.003911	$709,021	$0	0.0%
RGGI Recovery Charges				RGGI Recovery Charges					
22 All kWh	181,288,963	$0.001451	$263,050	22 All kWh	181,288,963	$0.001451	$263,050	$0	0.0%
Tax Act djustment				Tax Act djustment					
23 All kWh	181,288,963	-$0.000288	-$52,211	23 All kWh	181,288,963	-$0.000288	-$52,211	$0	0.0%
LRAM				LRAM					
24 All kWh	181,288,963	$0.000000	$0	24 All kWh	181,288,963	$0.000000	$0	$0	#DIV/0!
25 Total Charges	181,288,963		$24,004,333	25 Total Charges	181,288,963		$25,876,002	$1,871,669	7.8%
26 Average $/kWh			$0.132409	26 Average $/kWh			$0.142733	$0.010324	7.8%

{1} Rates effective 3/1/2023
{2} Proposed rates effective TBD
{3} Units are included with line 1 and therefore are not added into the total on line 3.

Jersey Central Power & Light Company

Based on 2022/2023 6+6 Weather Normalized Billing Determinants (Excludes SUT)

Residential Geothermal & Heat Pump Service (RGT)

Description of Charge	Weather Normalized 2022/2023 6+6 Units (a)	Current Rates {1} (b)	Revenue Based on Current Rates (c) = (a) x (b)	Description of Charge	Weather Normalized 2022/2023 6+6 Units (d)	Proposed Rates {2} (e)	Revenue Based on Proposed Rates (f) = (d) x (e)	Change in Revenue (g) = (f) - (c)	Percentage Change in Revenue (h) = (g) / (c)
Customer Charges				Customer Charges					
1 Standard Customer Charge	5,673	$6.61	$37,498	1 Standard Customer Charge	5,673	$8.51	$48,276	$10,778	28.7%
NGC per kWh Charges				NGC per kWh Charges					
2 On-Peak Summer kWh	1,806,677	-$0.000219	-$396	2 On-Peak Summer kWh	1,806,677	-$0.000219	-$396	$0	0.0%
3 Off-Peak Summer kWh	2,525,728	-$0.000219	-$553	3 Off-Peak Summer kWh	2,525,728	-$0.000219	-$553	$0	0.0%
4 All Winter kWh	9,882,330	-$0.000219	-$2,164	4 All Winter kWh	9,882,330	-$0.000219	-$2,164	$0	0.0%
5 Total NGC Charge	14,214,735		-$3,113	5 Total NGC Charge	14,214,735		-$3,113	$0	0.0%
SBC per kWh Charges				SBC per kWh Charges					
6 All kWh	14,214,735	$0.008378	$119,091	6 All kWh	14,214,735	$0.008378	$119,091	$0	0.0%
Distribution per kWh Charges				Distribution per kWh Charges					
7 On-Peak Summer kWh	1,806,677	$0.049096	$88,701	7 On-Peak Summer kWh	1,806,677	$0.063353	$114,458	$25,757	29.0%
8 Off-Peak Summer kWh	2,525,728	$0.022934	$57,925	8 Off-Peak Summer kWh	2,525,728	$0.029594	$74,746	$16,821	29.0%
9 All Winter kWh	9,882,330	$0.027542	$272,179	9 All Winter kWh	9,882,330	$0.034059	$336,582	$64,403	23.7%
10 Total Distribution kWh Charges	14,214,735		$418,805	10 Total Distribution kWh Charges	14,214,735		$525,786	$106,981	25.5%
BGS per kWh Charges				BGS per kWh Charges					
11 Summer - On-Peak kWh	1,806,677	$0.096185	$173,775	11 Summer - On-Peak kWh	1,806,677	$0.096185	$173,775	$0	0.0%
12 Summer - Off-Peak kWh	2,525,728	$0.050786	$128,272	12 Summer - Off-Peak kWh	2,525,728	$0.050786	$128,272	$0	0.0%
13 Winter - All kWh	9,882,330	$0.076409	$755,099	13 Winter - All kWh	9,882,330	$0.076409	$755,099	$0	0.0%
14 Total BGS Charges	14,214,735		$1,057,146	14 Total BGS Charges	14,214,735		$1,057,146	$0	0.0%
Transmission per kWh Charges				Transmission per kWh Charges					
15 Summer - All kWh	4,332,405	$0.014036	$60,810	15 Summer - All kWh	4,332,405	$0.014036	$60,810	$0	0.0%
16 Winter - All kWh	9,882,330	$0.014036	$138,708	16 Winter - All kWh	9,882,330	$0.014036	$138,708	$0	0.0%
17 Total Transmission Charges	14,214,735		$199,518	17 Total Transmission Charges	14,214,735		$199,518	$0	0.0%
ZEC Recovery Charges				ZEC Recovery Charges					
18 All kWh	14,214,735	$0.003911	$55,594	18 All kWh	14,214,735	$0.003911	$55,594	$0	0.0%
RGGI Recovery Charge				RGGI Recovery Charge					
19 All kWh	14,214,735	$0.001451	$20,626	19 All kWh	14,214,735	$0.001451	$20,626	$0	0.0%
Tax Act djustment				Tax Act djustment					
20 All kWh	14,214,735	-$0.000288	-$4,094	20 All kWh	14,214,735	-$0.000288	-$4,094	$0	0.0%
LRAM				LRAM					
21 All kWh	14,214,735	$0.000000	$0	21 All kWh	14,214,735	$0.000000	$0	$0	#DIV/0!
22 Total Charges			$1,901,071	22 Total Charges			$2,018,830	$117,759	6.2%

{1} Rates effective 3/1/2023
{2} Proposed rates effective TBD

Jersey Central Power & Light Company
Based on 2022/2023 6+6 Weather Normalized Billing Determinants (Excludes SUT)
General Service Secondary (GS)

Description of Charge	Weather Normalized 2022/2023 6+6 Units (a)	Current Rates {1} (b)	Revenue Based on Current Rates (c) = (a) x (b)	Description of Charge	Weather Normalized 2022/2023 6+6 Units (d)	Proposed Rates {2} (e)	Revenue Based on Proposed Rates (f) = (d) x (e)	Change in Revenue (g) = (f) - (c)	Percentage Change in Revenue (h) = (g) / (c)
Customer Charges				Customer Charges					
1 Single Phase Customer Charge	926,332.80	$3.84	$3,557,118	1 Single Phase Customer Charge	926,333	$4.98	$4,613,137	$1,056,019	29.7%
2 Three Phase Customer Charge	631,208.81	$13.78	$8,698,057	2 Three Phase Customer Charge	631,209	$17.89	$11,292,326	$2,594,269	29.8%
3 Supplemental OPWH {3}	169.00	$1.59	$269	3 Supplemental OPWH {3}	169	$2.74	$463	$194	72.1%
4 Supplemental CTWH {3}	454.00	$1.59	$722	4 Supplemental CTWH {3}	454	$2.74	$1,244	$522	72.3%
5 Supplemental Day/Night {3}	19,683.39	$3.14	$61,806	5 Supplemental Day/Night {3}	19,683	$4.08	$80,308	$18,502	29.9%
6 Supplemental Traffic Signal {3}	25,148.83	$14.32	$360,131	6 Supplemental Traffic Signal {3}	25,149	$18.59	$467,517	$107,386	29.8%
7 Total Customer Charges	1,557,541.605		$12,678,103	7 Total Customer Charges	1,557,542		$16,454,995	$3,776,892	29.8%
NGC per kWh Charges				NGC per kWh Charges					
8 First 1,000 kWh Summer	339,996,337	-$0.000219	-$74,459	8 First 1,000 kWh Summer	339,996,337	-$0.000219	-$74,459	$0	0.0%
9 First 1,000 kWh Winter	649,068,590	-$0.000219	-$142,146	9 First 1,000 kWh Winter	649,068,590	-$0.000219	-$142,146	$0	0.0%
10 Over 1,000 kWh Summer	2,028,609,190	-$0.000219	-$444,265	10 Over 1,000 kWh Summer	2,028,609,190	-$0.000219	-$444,265	$0	0.0%
11 Over 1,000 kWh Winter	3,472,005,138	-$0.000219	-$760,369	11 Over 1,000 kWh Winter	3,472,005,138	-$0.000219	-$760,369	$0	0.0%
12 OPWH-kWh Summer	9,446	-$0.000219	-$2	12 OPWH-kWh Summer	9,446	-$0.000219	-$2	$0	0.0%
13 OPWH-kWh Winter	24,556	-$0.000219	-$5	13 OPWH-kWh Winter	24,556	-$0.000219	-$5	$0	0.0%
14 CTWH-kWh Summer	21,915	-$0.000219	-$5	14 CTWH-kWh Summer	21,915	-$0.000219	-$5	$0	0.0%
15 CTWH-kWh Winter	85,482	-$0.000219	-$19	15 CTWH-kWh Winter	85,482	-$0.000219	-$19	$0	0.0%
16 Traffic Signal kWh Summer	2,023,230	-$0.000219	-$443	16 Traffic Signal kWh Summer	2,023,230	-$0.000219	-$443	$0	0.0%
17 Traffic Signal kWh Winter	4,374,325	-$0.000219	-$958	17 Traffic Signal kWh Winter	4,374,325	-$0.000219	-$958	$0	0.0%
18 Total NGC Charges	6,496,218,207		-$1,422,671	18 Total NGC Charges	6,496,218,207		-$1,422,671	$0	0.0%
SBC per kWh Charges				SBC per kWh Charges					
19 All kWh	6,496,218,207	$0.008378	$54,425,316	19 All kWh	6,496,218,207	$0.008378	$54,425,316	$0	0.0%
Distribution per kWh Charges				Distribution per kWh Charges					
20 First 1,000 kWh Summer	339,996,337	$0.062235	$21,159,672	20 First 1,000 kWh Summer	339,996,337	$0.080813	$27,476,124	$6,316,452	29.9%
21 First 1,000 kWh Winter	649,068,590	$0.057585	$37,376,615	21 First 1,000 kWh Winter	649,068,590	$0.074775	$48,534,104	$11,157,489	29.9%
22 Over 1,000 kWh Summer	2,028,609,190	$0.004977	$10,096,388	22 Over 1,000 kWh Summer	2,028,609,190	$0.006463	$13,110,901	$3,014,513	29.9%
23 Over 1,000 kWh Winter	3,472,005,138	$0.004977	$17,280,170	23 Over 1,000 kWh Winter	3,472,005,138	$0.006463	$22,439,569	$5,159,399	29.9%
24 OPWH-kWh Summer	9,446	$0.018382	$174	24 OPWH-kWh Summer	9,446	$0.022732	$215	$41	23.7%
25 OPWH-kWh Winter	24,556	$0.018382	$451	25 OPWH-kWh Winter	24,556	$0.022732	$558	$107	23.7%
26 CTWH-kWh Summer	21,915	$0.024212	$531	26 CTWH-kWh Summer	21,915	$0.029941	$656	$125	23.7%
27 CTWH-kWh Winter	85,482	$0.024212	$2,070	27 CTWH-kWh Winter	85,482	$0.029941	$2,559	$489	23.7%
28 Traffic Signal kWh Summer	2,023,230	$0.013042	$26,387	28 Traffic Signal kWh Summer	2,023,230	$0.016935	$34,263	$7,876	29.8%
29 Traffic Signal kWh Winter	4,374,325	$0.013042	$57,050	29 Traffic Signal kWh Winter	4,374,325	$0.016935	$74,079	$17,029	29.8%
30 Religious Hse of Wrshp Credit {4}	15,417,299	-$0.031728	-$489,160	30 Religious Hse of Wrshp Credit {4}	15,417,299	-$0.041199	-$635,177	-$146,017	29.9%
31 CBT Exemption {5}			-$151,251	31 CBT Exemption {5}			-$196,784	-$45,533	N/A
32 Total Distr. kWh Charges	6,496,218,207		$85,359,097	32 Total Distr. kWh Charges	6,496,218,207		$110,841,067	$25,481,970	29.9%
Distribution Demand Charges				Distribution Demand Charges					
33 Full Rate - Summer	5,222,023	$7.43	$38,799,630	33 Full Rate - Summer	5,222,023	$9.65	$50,392,520	$11,592,890	29.9%
34 Full Rate - Winter	8,051,386	$6.92	$55,715,589	34 Full Rate - Winter	8,051,386	$8.98	$72,301,443	$16,585,854	29.8%
35 Minimum Charge	4,521,668	$3.37	$15,238,022	35 Minimum Charge	4,521,668	$4.37	$19,759,690	$4,521,668	29.7%
36 Standby Demand	243	$3.42	$832	36 Standby Demand	243	$4.44	$1,080	$248	29.8%
37 Total Distr. kW Charges	17,795,320		$109,754,073	37 Total Distr. kW Charges	17,795,320		$142,454,733	$32,700,660	29.8%
BGS per kWh Charges				BGS per kWh Charges					
38 Summer-Non-Water Heating kWh	2,370,628,757	$0.070102	$166,185,817	38 Summer-Non-Water Heating kWh	2,370,628,757	$0.070102	$166,185,817	$0	0.0%
39 Winter-Non-Water Heating kWh	4,125,448,052	$0.069839	$288,117,167	39 Winter-Non-Water Heating kWh	4,125,448,052	$0.069839	$288,117,167	$0	0.0%
40 Summer-OPWH & CTWH kWh	31,360	$0.069971	$2,194	40 Summer-OPWH & CTWH kWh	31,360	$0.069971	$2,194	$0	0.0%
41 Winter-OPWH & CTWH kWh	110,038	$0.069773	$7,678	41 Winter-OPWH & CTWH kWh	110,038	$0.069773	$7,678	$0	0.0%
42 Total BGS Charges	6,496,218,207		$454,312,856	42 Total BGS Charges	6,496,218,207		$454,312,856	$0	0.0%
Transmission per kWh Charges				Transmission per kWh Charges					
43 All Non-Water Heating kWh	6,496,076,809	$0.014036	$91,178,934	43 All Non-Water Heating kWh	6,496,076,809	$0.014036	$91,178,934	$0	0.0%
44 OPWH & CTWH kWh	141,398	$0.014036	$1,985	44 OPWH & CTWH kWh	141,398	$0.014036	$1,985	$0	0.0%
45 Total Transmission Charges	6,496,218,207		$91,180,919	45 Total Transmission Charges	6,496,218,207		$91,180,919	$0	0.0%
ZEC Recovery Charges				ZEC Recovery Charges					
46 All kWh	6,496,218,207	$0.003911	$25,406,709	46 All kWh	6,496,218,207	$0.003911	$25,406,709	$0	0.0%
RGGI Recovery Charges				RGGI Recovery Charges					
47 All kWh	6,496,218,207	$0.001451	$9,426,013	47 All kWh	6,496,218,207	$0.001451	$9,426,013	$0	0.0%
Tax Act djustment				Tax Act djustment					
48 All kWh	6,496,218,207	-$0.000257	-$1,669,528	48 All kWh	6,496,218,207	-$0.000257	-$1,669,528	$0	0.0%
LRAM				LRAM					
49 All kWh	6,496,218,207	$0.000000	$0	49 All kWh	6,496,218,207	$0.000000	$0	$0	#DIV/0!
50 Total Charges	6,496,218,207		$839,450,887	50 Total Charges	6,496,218,207		$901,410,409	$61,959,522	7.4%

{1} Rates effective 3/1/2023
{2} Proposed rates effective TBD
{3} Units are included in lines 1 and 2 and therefore are not added into the total on line 7.
{4} Units are included with lines 20 through 23 and therefore are not added into the total on line 32.
{5} Total distribution reduction attributable to CBT Exempt accounts.

Jersey Central Power & Light Company

Based on 2022/2023 6+6 Weather Normalized Billing Determinants (Excludes SUT)

General Service Secondary Time-of-Day (GST)

Description of Charge	Weather Normalized 2022/2023 6+6 Units (a)	Current Rates {1} (b)	Revenue Based on Current Rates (c) = (a) x (b)	Description of Charge	Weather Normalized 2022/2023 6+6 Units (d)	Proposed Rates {2} (e)	Revenue Based on Proposed Rates (f) = (d) x (e)	Change in Revenue (g) = (f) - (c)	Percentage Change in Revenue (h) = (g) / (c)
Customer Charges				Customer Charges					
1 Single Phase Customer Charge	0	$33.36	$0	1 Single Phase Customer Charge	0	$43.31	$0	$0	0.0%
2 Three Phase Customer Charge	2,253	$47.60	$107,261	2 Three Phase Customer Charge	2,253	$61.79	$139,236	$31,975	29.8%
3 Total Customer Charges	2,253		$107,261	3 Total Customer Charges	2,253		$139,236	$31,975	29.8%
NGC per kWh Charges				NGC per kWh Charges					
4 Summer On-Peak kWh	67,156,292	-$0.000219	-$14,707	4 Summer On-Peak kWh	67,156,292	-$0.000219	-$14,707	$0	0.0%
5 Winter On-Peak kWh	125,103,601	-$0.000219	-$27,398	5 Winter On-Peak kWh	125,103,601	-$0.000219	-$27,398	$0	0.0%
6 Summer Off-Peak kWh	81,315,776	-$0.000219	-$17,808	6 Summer Off-Peak kWh	81,315,776	-$0.000219	-$17,808	$0	0.0%
7 Winter Off-Peak kWh	167,521,495	-$0.000219	-$36,687	7 Winter Off-Peak kWh	167,521,495	-$0.000219	-$36,687	$0	0.0%
8 Total NGC Charges	441,097,165		-$96,600	8 Total NGC Charges	441,097,165		-$96,600	$0	0.0%
SBC per kWh Charges				SBC per kWh Charges					
9 All kWh	441,097,165	$0.008378	$3,695,512	9 All kWh	441,097,165	$0.008378	$3,695,512	$0	0.0%
Distribution per kWh Charges				Distribution per kWh Charges					
10 Summer On-Peak kWh	67,156,292	$0.004835	$324,701	10 Summer On-Peak kWh	67,156,292	$0.004844	$325,305	$604	0.2%
11 Winter On-Peak kWh	125,103,601	$0.004835	$604,876	11 Winter On-Peak kWh	125,103,601	$0.004844	$606,002	$1,126	0.2%
12 Summer Off-Peak kWh	81,315,776	$0.004835	$393,162	12 Summer Off-Peak kWh	81,315,776	$0.004844	$393,894	$732	0.2%
13 Winter Off-Peak kWh	167,521,495	$0.004835	$809,966	13 Winter Off-Peak kWh	167,521,495	$0.004844	$811,474	$1,508	0.2%
14 CBT Exemption {3}			-$5,797	14 CBT Exemption {3}			-$7,200	-$1,403	N/A
15 Total Distr. kWh Charges	441,097,165		$2,126,908	15 Total Distr. kWh Charges	441,097,165		$2,129,475	$2,567	0.1%
Distribution Demand Charges				Distribution Demand Charges					
16 Full Rate - Summer	391,973	$7.84	$3,073,067	16 Full Rate - Summer	391,973	$10.75	$4,213,708	$1,140,641	37.1%
17 Full Rate - Winter	699,895	$7.33	$5,130,232	17 Full Rate - Winter	699,895	$10.05	$7,033,946	$1,903,714	37.1%
18 Minimum Charge	132,081	$3.42	$451,718	18 Minimum Charge	132,081	$4.69	$619,461	$167,743	37.1%
19 Standby Demand	0	$3.42	$0	19 Standby Demand	0	$4.44	$0	$0	0.0%
20 Total Distr. kW Charges	1,223,949		$8,655,017	20 Total Distr. kW Charges	1,223,949		$11,867,115	$3,212,098	37.1%
BGS per kWh Charges {4}				BGS per kWh Charges {4}					
21 Summer On-Peak kWh	67,156,292	$0.144540	$9,706,770	21 Summer On-Peak kWh	67,156,292	$0.144540	$9,706,770	$0	0.0%
22 Winter On-Peak kWh	125,103,601	$0.105621	$13,213,567	22 Winter On-Peak kWh	125,103,601	$0.105621	$13,213,567	$0	0.0%
23 Summer Off-Peak kWh	81,315,776	$0.094345	$7,671,737	23 Summer Off-Peak kWh	81,315,776	$0.094345	$7,671,737	$0	0.0%
24 Winter Off-Peak kWh	167,521,495	$0.075905	$12,715,719	24 Winter Off-Peak kWh	167,521,495	$0.075905	$12,715,719	$0	0.0%
25 Total BGS Charges	441,097,165		$43,307,793	25 Total BGS Charges	441,097,165		$43,307,793	$0	0.0%
Transmission per kWh Charges				Transmission per kWh Charges					
26 All kWh	441,097,165	$0.014036	$6,191,240	26 All kWh	441,097,165	$0.014036	$6,191,240	$0	0.0%
ZEC Recovery Charges				ZEC Recovery Charges					
27 All kWh	441,097,165	$0.003911	$1,725,131	27 All kWh	441,097,165	$0.003911	$1,725,131	$0	0.0%
RGGI Recovery Charges				RGGI Recovery Charges					
28 All kWh	441,097,165	$0.001451	$640,032	28 All kWh	441,097,165	$0.001451	$640,032	$0	0.0%
Tax Act djustment				Tax Act djustment					
29 All kWh	441,097,165	-$0.000200	-$88,219	29 All kWh	441,097,165	-$0.000200	-$88,219	$0	0.0%
LRAM				LRAM					
30 All kW	1,223,949	$0.00	$0	30 All kW	1,223,949	$0.00	$0	$0	#DIV/0!
30 Total Charges	441,097,165		$66,264,075	30 Total Charges	441,097,165		$69,510,715	$3,246,640	4.9%

{1} Rates effective 3/1/2023

{2} Proposed rates effective TBD

{3} Total distribution reduction attributable to CBT Exempt accounts.

{4} Based on Average BGS cost for RSCP and CIEP eligible accounts from 1/1/2022 to 12/31/2022

Jersey Central Power & Light Company

Based on 2022/2023 6+6 Weather Normalized Billing Determinants (Excludes SUT)

General Service Primary (GP)

	Description of Charge	Weather Normalized 2022/2023 6+6 Units (a)	Current Rates {1} (b)	Revenue Based on Current Rates (c) = (a) x (b)	Description of Charge	Weather Normalized 2022/2023 6+6 Units (d)	Proposed Rates {2} (e)	Revenue Based on Proposed Rates (f) = (d) x (e)	Change in Revenue (g) = (f) - (c)	Percentage Change in Revenue (h) = (g) / (c)
	Customer Charges				Customer Charges					
1	Customer Charge	7,189	$57.86	$415,974	Customer Charge	7,189	$75.11	$539,990	$124,016	29.8%
	NGC per kWh Charges				NGC per kWh Charges					
2	Summer On-Peak kWh	229,809,004	-$0.000208	-$47,800	Summer On-Peak kWh	229,809,004	-$0.000208	-$47,800	$0	0.0%
3	Winter On-Peak kWh	407,257,807	-$0.000208	-$84,710	Winter On-Peak kWh	407,257,807	-$0.000208	-$84,710	$0	0.0%
4	Summer Off-Peak kWh	339,077,597	-$0.000208	-$70,528	Summer Off-Peak kWh	339,077,597	-$0.000208	-$70,528	$0	0.0%
5	Winter Off-Peak kWh	618,350,704	-$0.000208	-$128,617	Winter Off-Peak kWh	618,350,704	-$0.000208	-$128,617	$0	0.0%
6	Total NGC Charges	1,594,495,112		-$331,655	Total NGC Charges	1,594,495,112		-$331,655	$0	0.0%
	SBC per kWh Charges				SBC per kWh Charges					
7	All kWh	1,594,495,112	$0.008378	$13,358,680	All kWh	1,594,495,112	$0.008378	$13,358,680	$0	0.0%
	Distribution per kWh Charges				Distribution per kWh Charges					
8	Summer On-Peak kWh	229,809,004	$0.003443	$791,232	Summer On-Peak kWh	229,809,004	$0.003452	$793,301	$2,069	0.3%
9	Winter On-Peak kWh	407,257,807	$0.003443	$1,402,189	Winter On-Peak kWh	407,257,807	$0.003452	$1,405,854	$3,665	0.3%
10	Summer Off-Peak kWh	339,077,597	$0.003443	$1,167,444	Summer Off-Peak kWh	339,077,597	$0.003452	$1,170,496	$3,052	0.3%
11	Winter Off-Peak kWh	618,350,704	$0.003443	$2,128,981	Winter Off-Peak kWh	618,350,704	$0.003452	$2,134,547	$5,566	0.3%
12	CBT Exemption {3}			-$14,130	CBT Exemption {3}			-$18,451	-$4,321	N/A
13	Total Distr. kWh Charges	1,594,495,112		$5,475,716	Total Distr. kWh Charges	1,594,495,112		$5,485,747	$10,031	0.2%
	Distribution Demand Charges				Distribution Demand Charges					
14	Full Rate - Summer	1,300,555	$6.03	$7,842,346	Full Rate - Summer	1,300,555	$8.29	$10,781,600	$2,939,254	37.5%
15	Full Rate - Winter	2,231,058	$5.60	$12,493,927	Full Rate - Winter	2,231,058	$7.69	$17,156,839	$4,662,912	37.3%
16	Minimum Charge	163,419	$2.04	$333,374	Minimum Charge	163,419	$2.80	$457,573	$124,199	37.3%
17	Standby Demand	0	$2.09	$0	Standby Demand	0	$2.87	$0	$0	0.0%
18	kVar Demand	1,747,067	$0.39	$681,356	kVar Demand	1,747,067	$0.54	$943,416	$262,060	38.5%
19	Total Distr. kW Charges	5,442,099		$21,351,003	Total Distr. kW Charges	5,442,099		$29,339,428	$7,988,425	37.4%
	BGS per kWh Charges {4}				BGS per kWh Charges {4}					
20	Summer kWh	568,886,601	$0.093296	$53,074,844	Summer kWh	568,886,601	$0.093296	$53,074,844	$0	0.0%
21	Winter kWh	1,025,608,511	$0.061445	$63,018,515	Winter kWh	1,025,608,511	$0.061445	$63,018,515	$0	0.0%
22	DSSAC - All kWh	1,594,495,112	$0.000150	$239,174	DSSAC - All kWh	1,594,495,112	$0.000150	$239,174	$0	0.0%
23	Capacity Obligation - kW days	125,829,109	$0.254800	$32,061,257	Capacity Obligation - kW days	125,829,109	$0.254800	$32,061,257	$0	0.0%
24	Total BGS Charges	1,594,495,112		$148,393,790	Total BGS Charges	1,594,495,112		$148,393,790	$0	0.0%
	Transmission per kWh Charges				Transmission per kWh Charges					
25	All kWh	1,594,495,112	$0.008523	$13,589,882	All kWh	1,594,495,112	$0.008523	$13,589,882	$0	0.0%
	ZEC Recovery Charges				ZEC Recovery Charges					
26	All kWh	1,594,495,112	$0.003911	$6,236,070	All kWh	1,594,495,112	$0.003911	$6,236,070	$0	0.0%
	RGGI Recovery Charges				RGGI Recovery Charges					
27	All kWh	1,594,495,112	$0.001451	$2,313,612	All kWh	1,594,495,112	$0.001451	$2,313,612	$0	0.0%
	Tax Act djustment				Tax Act djustment					
28	All kWh	1,594,495,112	-$0.000144	-$229,607	All kWh	1,594,495,112	-$0.000144	-$229,607	$0	0.0%
	LRAM				LRAM					
29	All kW	5,442,099	$0.00	$0	All kW	5,442,099	$0.00	$0	$0	#DIV/0!
29	Total Charges	1,594,495,112		$210,573,465	Total Charges	1,594,495,112		$218,695,937	$8,122,472	3.9%

{1} Rates effective 3/1/2023
{2} Proposed rates effective TBD
{3} Total distribution reduction attributable to CBT Exempt accounts.
{4} Based on BGS Energy and Capacity Cost from 1/1/2019 to 12/31/2019

Jersey Central Power & Light Company

Based on 2022/2023 6+6 Weather Normalized Billing Determinants (Excludes SUT)

General Service Transmission (GT)

Description of Charge	Weather Normalized 2022/2023 6+6 Units (a)	Current Rates {1} (b)	Revenue Based on Current Rates (c) = (a) x (b)	Description of Charge	Weather Normalized 2022/2023 6+6 Units (d)	Proposed Rates {2} (e)	Revenue Based on Proposed Rates (f) = (d) x (e)	Change in Revenue (g) = (f) - (c)	Percentage Change in Revenue (h) = (g) / (c)
Customer Charges				Customer Charges					
1 Customer Charges	2,080	$248.50	$516,996	1 Customer Charges	2,080	$322.60	$671,159	$154,163	29.8%
NGC per kWh Charges				NGC per kWh Charges					
2 Summer kWh (w/o 230 kV)	483,333,546	-$0.000204	-$98,600	2 Summer kWh (w/o 230 kV)	483,333,546	-$0.000204	-$98,600	$0	0.0%
3 Winter kWh (w/o 230 kV)	944,258,549	-$0.000204	-$192,629	3 Winter kWh (w/o 230 kV)	944,258,549	-$0.000204	-$192,629	$0	0.0%
4 230 kV Summer kWh	42,685,402	-$0.000200	-$8,537	4 230 kV Summer kWh	42,685,402	-$0.000200	-$8,537	$0	0.0%
5 230 kV Winter kWh	85,851,294	-$0.000200	-$17,170	5 230 kV Winter kWh	85,851,294	-$0.000200	-$17,170	$0	0.0%
6 GT Prov (d) Summer	67,534,458	$0.000000	$0	6 GT Prov (d) Summer	67,534,458	$0.000000	$0	$0	0.0%
7 GT Prov (d) Winter	139,814,367	$0.000000	$0	7 GT Prov (d) Winter	139,814,367	$0.000000	$0	$0	0.0%
8 DOD Summer kWh	55,455,726	-$0.000204	-$11,313	8 DOD Summer kWh	55,455,726	-$0.000204	-$11,313	$0	0.0%
9 DOD Winter kWh	97,331,356	-$0.000204	-$19,856	9 DOD Winter kWh	97,331,356	-$0.000204	-$19,856	$0	0.0%
10 Total NGC Charges	1,916,264,698		-$348,105	10 Total NGC Charges	1,916,264,698		-$348,105	$0	0.0%
SBC per kWh Charges				SBC per kWh Charges					
11 All kWh	1,916,264,698	$0.008378	$16,054,466	11 All kWh	1,916,264,698	$0.008378	$16,054,466	$0	0.0%
Distribution per kWh Charges				Distribution per kWh Charges					
12 Summer On-Peak kWh	252,743,385	$0.002657	$671,539	12 Summer On-Peak kWh	252,743,385	$0.002673	$675,583	$4,044	0.6%
13 Winter On-Peak kWh	482,134,921	$0.002657	$1,281,032	13 Winter On-Peak kWh	482,134,921	$0.002673	$1,288,747	$7,715	0.6%
14 Summer Off-Peak kWh	328,731,289	$0.002657	$873,439	14 Summer Off-Peak kWh	328,731,289	$0.002673	$878,699	$5,260	0.6%
15 Winter Off-Peak kWh	645,306,278	$0.002657	$1,714,579	15 Winter Off-Peak kWh	645,306,278	$0.002673	$1,724,904	$10,325	0.6%
16 230 kV Discount {3}	128,536,696	-$0.000943	-$121,210	16 230 kV Discount {3}	128,536,696	-$0.000949	-$121,981	-$771	0.6%
17 DOD Summer Credit {3}	55,455,726	-$0.001727	-$95,772	17 DOD Summer Credit {3}	55,455,726	-$0.001737	-$96,327	-$555	0.6%
18 DOD Winter Credit {3}	97,331,356	-$0.001727	-$168,091	18 DOD Winter Credit {3}	97,331,356	-$0.001737	-$169,065	-$974	0.6%
19 GT Prov (d) Summer	67,534,458	$0.000000	$0	19 GT Prov (d) Summer	67,534,458	$0.000000	$0	$0	0.0%
20 GT Prov (d) Winter	139,814,367	$0.000000	$0	20 GT Prov (d) Winter	139,814,367	$0.000000	$0	$0	0.0%
20 CBT Exemption {4}			-$17,704	20 CBT Exemption {4}			-$23,362	-$5,658	N/A
21 Total Distr. kWh Charges	1,916,264,698		$4,137,812	21 Total Distr. kWh Charges	1,916,264,698		$4,157,198	$19,386	0.5%
Distribution Demand Charges				Distribution Demand Charges					
22 Full Rate - Summer	1,443,646	$3.87	$5,586,910	22 Full Rate - Summer	1,443,646	$5.32	$7,680,197	$2,093,287	37.5%
23 Full Rate - Winter	2,551,730	$3.87	$9,875,196	23 Full Rate - Winter	2,551,730	$5.32	$13,575,205	$3,700,009	37.5%
24 Minimum Charge	517,901	$1.17	$605,944	24 Minimum Charge	517,901	$1.61	$833,820	$227,876	37.6%
25 Standby Demand	195,537	$1.00	$195,537	25 Standby Demand	195,537	$1.38	$269,841	$74,304	38.0%
26 230 kV Discount {5}	237,216	-$1.03	-$244,332	26 230 kV Discount {5}	237,216	-$1.42	-$336,847	-$92,515	37.9%
27 Minimum Charge Reduction	0	-$0.49	$0	27 Minimum Charge Reduction	0	-$0.67	$0	$0	0.0%
28 DOD Summer kW Credit {5}	127,051	-$2.57	-$326,521	28 DOD Summer kW Credit {5}	127,051	-$3.54	-$449,760	-$123,239	37.7%
29 DOD Winter kW Credit {5}	201,915	-$2.57	-$518,922	29 DOD Winter kW Credit {5}	201,915	-$3.54	-$714,780	-$195,858	37.7%
30 DOD Minimum kW Credit {5}	7,814	-$0.77	-$6,017	30 DOD Minimum kW Credit {5}	7,814	-$1.06	-$8,283	-$2,266	37.7%
31 GT Prov (d) Summer	242,396	$0.41	$99,383	31 GT Prov (d) Summer	242,396	$0.54	$130,894	$31,511	31.7%
32 GT Prov (d) Winter	499,477	$0.41	$204,786	32 GT Prov (d) Winter	499,477	$0.54	$269,718	$64,932	31.7%
33 kVar Demand	1,853,548	$0.38	$704,348	33 kVar Demand	1,853,548	$0.52	$963,845	$259,497	36.8%
34 Total Distr. kW Charges	7,304,235		$16,176,312	34 Total Distr. kW Charges	7,304,235		$22,213,850	$6,037,538	37.3%
BGS per kWh Charges {6}				BGS per kWh Charges {6}					
35 Summer kWh	649,009,132	$0.087762	$56,958,339	35 Summer kWh	649,009,132	$0.087762	$56,958,339	$0	0.0%
36 Winter kWh	1,267,255,566	$0.064545	$81,795,011	36 Winter kWh	1,267,255,566	$0.064545	$81,795,011	$0	0.0%
37 DSSAC - All kWh	1,916,264,698	$0.000150	$287,440	37 DSSAC - All kWh	1,916,264,698	$0.000150	$287,440	$0	0.0%
38 Capacity Obligation - kW days	105,690,354	$0.254800	$26,929,902	38 Capacity Obligation - kW days	105,690,354	$0.254800	$26,929,902	$0	0.0%
39 Total BGS Charges	1,916,264,698		$165,970,692	39 Total BGS Charges	1,916,264,698		$165,970,692	$0	0.0%
Transmission per kWh Charges				Transmission per kWh Charges					
40 All kWh - Excluding 230 kV kWh	1,580,379,177	$0.007512	$11,871,808	40 All kWh - Excluding 230 kV kWh	1,580,379,177	$0.007512	$11,871,808	$0	0.0%
41 230 kV kWh	335,885,521	$0.002035	$683,527	41 230 kV kWh	335,885,521	$0.002035	$683,527	$0	0.0%
	1,916,264,698		12,555,335		1,916,264,698		12,555,335	$0	0.0%
ZEC Recovery Charges				ZEC Recovery Charges					
42 All kWh	1,916,264,698	$0.003911	$7,494,511	42 All kWh	1,916,264,698	$0.003911	$7,494,511	$0	0.0%
RGGI Recovery Charges				RGGI Recovery Charges					
43 All kWh	1,916,264,698	$0.001451	$2,780,500	43 All kWh	1,916,264,698	$0.001451	$2,780,500	$0	0.0%
Tax Act djustment				Tax Act djustment					
44 All kWh	1,916,264,698	-$0.000087	-$166,715	44 All kWh	1,916,264,698	-$0.000087	-$166,715	$0	0.0%
LRAM				LRAM					
45 All kW	7,304,235	$0.00	$0	45 All kW	7,304,235	$0.00	$0	$0	#DIV/0!
46 Total Charges	1,916,264,698		$225,171,804	46 Total Charges	1,916,264,698		$231,382,891	$6,211,087	2.8%
{1} Rates effective 3/1/2023			$46,645,777	{4} Total distribution reduction attributable to CBT Exempt accounts.			$52,856,864	$6,211,087	13.3%

{2} Proposed rates effective TBD
{3} Units are included in lines 12 through 15 and are therefore excluded from the total on line 21.
{5} Units are included in lines 22 to 24 and are therefore excluded from the total on line 34.
{6} Based on BGS Energy and Capacity Cost from 1/1/2019 to 12/31/2019

Jersey Central Power & Light Company

Based on 2022/2023 6+6 Weather Normalized Billing Determinants (Excludes SUT)

Lighting Summary

Description of Charge	Weather Normalized 2022/2023 6+6 Units (a)	Revenue Based on Current Rates {1} (b)	Description of Charge	Weather Normalized 2022/2023 6+6 Units (c)	Revenue Based on Proposed Rates {2} (d)	Change in Revenue (e) = (d) - (b)	Percentage Change in Revenue (f) = (e) / (b)
Distribution Charges			Distribution Charges				
1 Fixture Charges	2,544,359	$13,503,340	1 Fixture Charges	2,544,359	$15,441,909	$1,938,569	14.4%
2 Miscellaneous Charges	140,504	$393,235	2 Miscellaneous Charges	140,504	$449,938	$56,703	14.4%
3 kWh Charges	114,099,670	$5,357,367	3 kWh Charges	114,099,670	$6,132,558	$775,191	14.5%
4 Total Distribution Charges	114,099,670	$19,253,942	4 Total Distribution Charges	114,099,670	$22,024,405	$2,770,463	14.4%
5 NGC	114,099,670	-$24,989	5 NGC	114,099,670	-$24,989	$0	0.0%
6 SBC	114,099,670	$955,927	6 SBC	114,099,670	$955,927	$0	0.0%
7 BGS	114,099,670	$6,237,374	7 BGS	114,099,670	$6,237,374	$0	0.0%
8 Transmission	114,099,670	$0	8 Transmission	114,099,670	$0	$0	0.0%
9 System Control Charges	114,099,670	$446,243	9 System Control Charges	114,099,670	$446,243	$0	0.0%
10 RGGI Recovery Charges	114,099,670	$165,557	10 RGGI Recovery Charges	114,099,670	$165,557	$0	0.0%
11 Storm Recovery Charges	114,099,670	-$167,726	11 Storm Recovery Charges	114,099,670	-$167,726	$0	0.0%
12 Total Charges {3}	114,099,670	$26,866,328	12 Total Charges {3}	114,099,670	$29,636,791	$2,770,463	10.3%

{1} Rates effective 3/1/2023
{2} Proposed rates effective TBD
{3} Total of lines 4 through 11.

Jersey Central Power & Light Company

Based on 2022/2023 6+6 Weather Normalized Billing Determinants (Excludes SUT)

Outdoor Lighting Service (OL)

Description of Charge	Monthly kWh Per Unit	Weather Normalized 2022/2023 6+6 Units (a)	Current Rates {1} (b)	Revenue Based on Current Rates (c) = (a) x (b)	Description of Charge	Weather Normalized 2022/2023 6+6 Units (d)	Proposed Rates {2} (e)	Revenue Based on Proposed Rates (f) = (d) x (e)	Change in Revenue (g) = (f) - (c)	Percentage Change in Revenue (h) = (g) / (c)
Area Lighting Fixture Charges					Area Lighting Fixture Charges					
1 100 Watt Lamp (121 Watt Total)	42	24,736	$2.51	$62,087	1 100 Watt Lamp (121 Watt Total)	24,736	$2.87	$70,992	$8,905	
2 175 Watt Lamp (211 Watt Total)	74	37,734	$2.51	$94,711	2 175 Watt Lamp (211 Watt Total)	37,734	$2.87	$108,295	$13,584	
High Pressure Sodium					High Pressure Sodium					
3 70 Watt HPS (99 Watt Total)	35	295	$10.41	$3,074	3 70 Watt HPS (99 Watt Total)	295	$11.91	$3,517	$443	
4 100 Watt HPS (137 Watt Total)	48	970	$10.41	$10,093	4 100 Watt HPS (137 Watt Total)	970	$11.91	$11,548	$1,455	
Flood Lighting Fixture Charges					Flood Lighting Fixture Charges					
5 150 Watt Lamp (176 Watt Total)	62	60,453	$12.23	$739,334	5 150 Watt Lamp (176 Watt Total)	60,453	$13.99	$845,731	$106,397	
6 250 Watt Lamp (293 Watt Total)	103	57,558	$12.85	$739,625	6 250 Watt Lamp (293 Watt Total)	57,558	$14.70	$846,108	$106,483	
7 400 Watt Lamp (498 Watt Total)	174	61,572	$13.19	$812,129	7 400 Watt Lamp (498 Watt Total)	61,572	$15.09	$929,115	$116,986	
8 Total Fixture Charges		243,317		$2,461,053	8 Total Fixture Charges	243,317		$2,815,306	$354,253	14.4%
Miscellaneous Charges					Miscellaneous Charges					
9 Spans Furnished Prior to 2/6/79		47,206	$0.64	$30,212	9 Spans Furnished Prior to 2/6/79	47,206	$0.73	$34,460	$4,248	
10 Spans Furnished After 2/6/79		20,950	$3.17	$66,411	10 Spans Furnished After 2/6/79	20,950	$3.63	$76,047	$9,636	
11 Transformers		633	$2.75	$1,740	11 Transformers	633	$3.15	$1,993	$253	
12 Poles Furnished Prior to 2/6/79		33,194	$0.68	$22,572	12 Poles Furnished Prior to 2/6/79	33,194	$0.78	$25,892	$3,320	
13 35' Poles Furnished After 2/6/79		10,939	$6.28	$68,696	13 35' Poles Furnished After 2/6/79	10,939	$7.18	$78,541	$9,845	
14 40' Poles Furnished After 2/6/79		957	$7.03	$6,727	14 40' Poles Furnished After 2/6/79	957	$8.04	$7,693	$966	
15 Total Miscellaneous Charges		113,878		$196,358	15 Total Miscellaneous Charges	113,878		$224,626	$28,268	14.4%
NGC per kWh Charges					NGC per kWh Charges					
16 Summer kWh		8,014,391	-$0.000219	-$1,755	16 Summer kWh	8,014,391	-$0.000219	-$1,755	$0	0.0%
17 Winter kWh		16,257,272	-$0.000219	-$3,560	17 Winter kWh	16,257,272	-$0.000219	-$3,560	$0	0.0%
18 Total NGC Charge		24,271,662		-$5,315	18 Total NGC Charge	24,271,662		-$5,315	$0	0.0%
SBC per kWh Charges					SBC per kWh Charges					
19 All kWh		24,271,662	$0.008378	$203,348	19 All kWh	24,271,662	$0.008378	$203,348	$0	0.0%
Distribution per kWh Charges					Distribution per kWh Charges					
20 All kWh		24,271,662	$0.046926	$1,138,972	20 All kWh	24,271,662	$0.053716	$1,303,777	$164,805	14.5%
21 CBT Exemption {3}		0		-$186	21 CBT Exemption {3}	0		-$211	-$25	N/A
22 Total Distribution Charge		24,271,662		$1,138,786	22 Total Distribution Charge	24,271,662		$1,303,566	$164,780	14.5%
BGS per kWh Charges					BGS per kWh Charges					
23 Summer kWh		8,014,391	$0.054268	$434,925	23 Summer kWh	8,014,391	$0.054268	$434,925	$0	0.0%
24 Winter kWh		16,257,272	$0.054860	$891,874	24 Winter kWh	16,257,272	$0.054860	$891,874	$0	0.0%
25 Total BGS Charge		24,271,662		$1,326,799	25 Total BGS Charge	24,271,662		$1,326,799	$0	0.0%
Transmission per kWh Charges					Transmission per kWh Charges					
26 All kWh		24,271,662	$0.000000	$0	26 All kWh	24,271,662	$0.000000	$0	$0	#DIV/0!
ZEC Recovery Charges					ZEC Recovery Charges					
27 All kWh		24,271,662	$0.003911	$94,926	27 All kWh	24,271,662	$0.003911	$94,926	$0	0.0%
RGGI Recovery Charges					RGGI Recovery Charges					
28 All kWh		24,271,662	$0.001451	$35,218	28 All kWh	24,271,662	$0.001451	$35,218	$0	0.0%
Tax Act djustment					Tax Act djustment					
29 All kWh		24,271,662	-$0.001470	-$35,679	29 All kWh	24,271,662	-$0.001470	-$35,679	$0	0.0%
LRAM					LRAM					
30 All kWh		24,271,662	$0.000000	$0	30 All kWh	24,271,662	$0.000000	$0	$0	#DIV/0!
30 Total Charges		24,271,662		$5,415,494	30 Total Charges	24,271,662		$5,962,795	$547,301	10.1%

{1} Rates effective 3/1/2023

{2} Proposed rates effective TBD

{3} Total distribution reduction attributable to CBT Exempt accounts.

Jersey Central Power & Light Company

Based on 2022/2023 6+6 Weather Normalized Billing Determinants (Excludes SUT)

Sodium Vapor Street Lighting Service (SVL)

Description of Charge	Monthly kWh Per Unit	Weather Normalized 2022/2023 6+6 Units (a)	Current Rates {1} (b)	Revenue Based on Current Rates (c) = (a) x (b)	Description of Charge	Weather Normalized 2022/2023 6+6 Units (d)	Proposed Rates {2} (e)	Revenue Based on Proposed Rates (f) = (d) x (e)	Change in Revenue (g) = (f) - (c)	Percentage Change in Revenue (h) = (g) / (c)
Company Lighting Fixture Charges					Company Lighting Fixture Charges					
1 50 Watt Lamp (60 Watt Total)	21	570,975	$6.08	$3,471,529	1 50 Watt Lamp (60 Watt Total)	570,975	$6.95	$3,968,277	$496,748	
2 70 Watt Lamp (85 Watt Total)	30	209,763	$6.08	$1,275,362	2 70 Watt Lamp (85 Watt Total)	209,763	$6.95	$1,457,856	$182,494	
3 100 Watt Lamp (121 Watt Total)	42	338,149	$6.08	$2,055,948	3 100 Watt Lamp (121 Watt Total)	338,149	$6.95	$2,350,138	$294,190	
4 150 Watt Lamp (176 Watt Total)	62	88,886	$6.08	$540,427	4 150 Watt Lamp (176 Watt Total)	88,886	$6.95	$617,758	$77,331	
5 250 Watt Lamp (293 Watt Total)	103	86,592	$7.19	$622,598	5 250 Watt Lamp (293 Watt Total)	86,592	$8.22	$711,788	$89,190	
6 400 Watt Lamp (498 Watt Total)	174	12,536	$7.19	$90,133	6 400 Watt Lamp (498 Watt Total)	12,536	$8.22	$103,046	$12,913	
Company Seasonal Fixture Charges					Company Seasonal Fixture Charges					
7 50 Watt Lamp (60 Watt Total)		156	$6.08	$948	7 50 Watt Lamp (60 Watt Total)	156	$6.95	$1,084	$136	
8 70 Watt Lamp (85 Watt Total)		216	$6.08	$1,313	8 70 Watt Lamp (85 Watt Total)	216	$6.95	$1,501	$188	
9 100 Watt Lamp (121 Watt Total)		264	$6.08	$1,605	9 100 Watt Lamp (121 Watt Total)	264	$6.95	$1,835	$230	
10 150 Watt Lamp (176 Watt Total)		168	$6.08	$1,021	10 150 Watt Lamp (176 Watt Total)	168	$6.95	$1,168	$147	
11 250 Watt Lamp (293 Watt Total)		0	$7.19	$0	11 250 Watt Lamp (293 Watt Total)	0	$8.22	$0	$0	
12 400 Watt Lamp (498 Watt Total)		0	$7.19	$0	12 400 Watt Lamp (498 Watt Total)	0	$8.22	$0	$0	
Contribution Lighting Fixture Charges					Contribution Lighting Fixture Charges					
13 50 Watt Lamp (60 Watt Total)	21	119,291	$1.71	$203,988	13 50 Watt Lamp (60 Watt Total)	119,291	$1.96	$233,811	$29,823	
14 70 Watt Lamp (85 Watt Total)	30	84,528	$1.71	$144,543	14 70 Watt Lamp (85 Watt Total)	84,528	$1.96	$165,675	$21,132	
15 100 Watt Lamp (121 Watt Total)	42	138,118	$1.71	$236,182	15 100 Watt Lamp (121 Watt Total)	138,118	$1.96	$270,711	$34,529	
16 150 Watt Lamp (176 Watt Total)	62	31,826	$1.71	$54,422	16 150 Watt Lamp (176 Watt Total)	31,826	$1.96	$62,379	$7,957	
17 250 Watt Lamp (293 Watt Total)	103	6,400	$1.71	$10,945	17 250 Watt Lamp (293 Watt Total)	6,400	$1.96	$12,545	$1,600	
18 400 Watt Lamp (498 Watt Total)	174	1,848	$1.71	$3,160	18 400 Watt Lamp (498 Watt Total)	1,848	$1.96	$3,622	$462	
Contribution Seasonal Fixture Charges					Contribution Seasonal Fixture Charges					
19 50 Watt Lamp (60 Watt Total)		192	$1.71	$328	19 50 Watt Lamp (60 Watt Total)	192	$1.96	$376	$48	
20 70 Watt Lamp (85 Watt Total)		12	$1.71	$21	20 70 Watt Lamp (85 Watt Total)	12	$1.96	$24	$3	
21 100 Watt Lamp (121 Watt Total)		768	$1.71	$1,313	21 100 Watt Lamp (121 Watt Total)	768	$1.96	$1,505	$192	
22 150 Watt Lamp (176 Watt Total)		0	$1.71	$0	22 150 Watt Lamp (176 Watt Total)	0	$1.96	$0	$0	
23 250 Watt Lamp (293 Watt Total)		0	$1.71	$0	23 250 Watt Lamp (293 Watt Total)	0	$1.96	$0	$0	
24 400 Watt Lamp (498 Watt Total)		0	$1.71	$0	24 400 Watt Lamp (498 Watt Total)	0	$1.96	$0	$0	
Contribution Reduced Hours Fixture Charges					Contribution Reduced Hours Fixture Charges					
25 150 Watt Lamp (176 Watt Total)	29	0	$1.71	$0	25 150 Watt Lamp (176 Watt Total)	0	$1.96	$0	$0	
Customer Lighting Fixture Charges					Customer Lighting Fixture Charges					
26 50 Watt Lamp (60 Watt Total)	21	204	$0.83	$169	26 50 Watt Lamp (60 Watt Total)	204	$0.95	$194	$25	
27 70 Watt Lamp (85 Watt Total)	30	168	$0.83	$139	27 70 Watt Lamp (85 Watt Total)	168	$0.95	$160	$21	
28 100 Watt Lamp (121 Watt Total)	42	2,628	$0.83	$2,181	28 100 Watt Lamp (121 Watt Total)	2,628	$0.95	$2,497	$316	
29 150 Watt Lamp (176 Watt Total)	62	2,208	$0.83	$1,832	29 150 Watt Lamp (176 Watt Total)	2,208	$0.95	$2,097	$265	
30 250 Watt Lamp (293 Watt Total)	103	758	$0.83	$629	30 250 Watt Lamp (293 Watt Total)	758	$0.95	$720	$91	
31 400 Watt Lamp (498 Watt Total)	174	432	$0.83	$359	31 400 Watt Lamp (498 Watt Total)	432	$0.95	$410	$51	
32 Total Fixture Charges		1,697,087		$8,721,095	32 Total Fixture Charges	1,697,087		$9,971,177	$1,250,082	14.3%
Miscellaneous Charges					Miscellaneous Charges					
33 Pole Charge		20,841	$8.10	$168,815	33 Pole Charge	20,841	$9.27	$193,199	$24,384	
34 Fixture Service		660	$0.97	$640	34 Fixture Service	660	$1.11	$733	$93	
35 Total Miscellaneous Charges		21,501		$169,455	35 Total Miscellaneous Charges	21,501		$193,932	$24,477	14.4%
NGC per kWh Charges					NGC per kWh Charges					
36 Summer kWh		20,364,545	-$0.000219	-$4,460	36 Summer kWh	20,364,545	-$0.000219	-$4,460	$0	0.0%
37 Winter kWh		42,906,600	-$0.000219	-$9,397	37 Winter kWh	42,906,600	-$0.000219	-$9,397	$0	0.0%
38 All kWh		63,271,146		-$13,857	38 All kWh	63,271,146		-$13,857	$0	0.0%
SBC per kWh Charges					SBC per kWh Charges					
39 All kWh		63,271,146	$0.008378	$530,086	39 All kWh	63,271,146	$0.008378	$530,086	$0	0.0%
Distribution per kWh Charges					Distribution per kWh Charges					
40 Seasonal Distr. Charge {3}		67,908	$0.046926	$3,187	40 Seasonal Distr. Charge {3}	67,908	$0.053716	$3,648	$461	
41 Reduced Lighting Hours Adj {4}		0	$0.046926	$0	41 Reduced Lighting Hours Adj {4}	0	$0.053716	$0	$0	
42 All kWh		63,271,146	$0.046926	$2,969,062	42 All kWh	63,271,146	$0.053716	$3,398,673	$429,611	
43 Total Distribution Charge		63,271,146		$2,972,249		63,271,146		$3,402,321	$430,072	14.5%
BGS per kWh Charges					BGS per kWh Charges					
44 Summer kWh		20,364,545	$0.054268	$1,105,143	44 Summer kWh	20,364,545	$0.054268	$1,105,143	$0	0.0%
45 Winter kWh		42,906,600	$0.054860	$2,353,856	45 Winter kWh	42,906,600	$0.054860	$2,353,856	$0	0.0%
46 Total BGS Charge		63,271,146		$3,458,999	46 Total BGS Charge	63,271,146		$3,458,999	$0	0.0%
Transmission per kWh Charges					Transmission per kWh Charges					
47 All kWh		63,271,146	$0.000000	$0	47 All kWh	63,271,146	$0.000000	$0	$0	0.0%
System Control Charges					System Control Charges					
48 All kWh		63,271,146	$0.003911	$247,453	48 All kWh	63,271,146	$0.003911	$247,453	$0	0.0%
RGGI Recovery Charges					RGGI Recovery Charges					
49 All kWh		63,271,146	$0.001451	$91,806	49 All kWh	63,271,146	$0.001451	$91,806	$0	0.0%
Tax Act djustment					Tax Act djustment					
50 All kWh		63,271,146	-$0.001470	-$93,009	50 All kWh	63,271,146	-$0.001470	-$93,009	$0	0.0%
LRAM					LRAM					
51 All kWh		63,271,146	$0.000000	$0	51 All kWh	63,271,146	$0.000000	$0	$0	#DIV/0!
52 Total Charges		63,271,146		$16,084,277	52 Total Charges	63,271,146		$17,788,908	$1,704,631	10.6%

{1} Rates effective 3/1/2023
{2} Proposed rates effective TBD
{3} Distribution kWh charge applied to kWh that seasonal lights would have used if they continued to operate
{4} Distribution kWh charge applied to additional kWh that lights would have used on the standard illumination sched

Jersey Central Power & Light Company

Based on 2022/2023 6+6 Weather Normalized Billing Determinants (Excludes SUT)

Mercury Vapor Street Lighting Service (MVL)

Description of Charge	Monthly kWh Per Unit	Weather Normalized 2022/2023 6+6 Units (a)	Current Rates {1} (b)	Revenue Based on Current Rates (c) = (a) x (b)	Description of Charge	Weather Normalized 2022/2023 6+6 Units (d)	Proposed Rates {2} (e)	Revenue Based on Proposed Rates (f) = (d) x (e)	Change in Revenue (g) = (f) - (c)	Percentage Change in Revenue (h) = (g) / (c)
Company Lighting Fixture Charges					Company Lighting Fixture Charges					
1 100 Watt Lamp (121 Watt Total)	42	438,589	$4.24	$1,859,619	1 100 Watt Lamp (121 Watt Total)	438,589	$4.85	$2,127,158	$267,539	
2 175 Watt Lamp (211 Watt Total)	74	18,569	$4.24	$78,733	2 175 Watt Lamp (211 Watt Total)	18,569	$4.85	$90,061	$11,328	
3 250 Watt Lamp (295 Watt Total)	103	5,727	$4.24	$24,284	3 250 Watt Lamp (295 Watt Total)	5,727	$4.85	$27,777	$3,493	
4 400 Watt Lamp (468 Watt Total)	164	1,574	$4.60	$7,240	4 400 Watt Lamp (468 Watt Total)	1,574	$5.26	$8,278	$1,038	
5 700 Watt Lamp (803 Watt Total)	281	0	$5.57	$0	5 700 Watt Lamp (803 Watt Total)	0	$6.37	$0	$0	
6 1000 Watt Lamp (1135 Watt Total)	397	0	$5.57	$0	6 1000 Watt Lamp (1135 Watt Total)	0	$6.37	$0	$0	
Company Seasonal Fixture Charges					Company Seasonal Fixture Charges					
7 100 Watt Lamp (121 Watt Total)		0	$4.24	$0	7 100 Watt Lamp (121 Watt Total)	0	$4.85	$0	$0	
8 175 Watt Lamp (211 Watt Total)		0	$4.24	$0	8 175 Watt Lamp (211 Watt Total)	0	$4.85	$0	$0	
9 250 Watt Lamp (295 Watt Total)		0	$4.24	$0	9 250 Watt Lamp (295 Watt Total)	0	$4.85	$0	$0	
10 400 Watt Lamp (468 Watt Total)		0	$4.60	$0	10 400 Watt Lamp (468 Watt Total)	0	$5.26	$0	$0	
11 700 Watt Lamp (803 Watt Total)		0	$5.57	$0	11 700 Watt Lamp (803 Watt Total)	0	$6.37	$0	$0	
12 1000 Watt Lamp (1135 Watt Total)		0	$5.57	$0	12 1000 Watt Lamp (1135 Watt Total)	0	$6.37	$0	$0	
Contribution Lighting Fixture Charges					Contribution Lighting Fixture Charges					
13 100 Watt Lamp (121 Watt Total)	42	11,333	$1.61	$18,246	13 100 Watt Lamp (121 Watt Total)	11,333	$1.84	$20,852	$2,606	
14 175 Watt Lamp (211 Watt Total)	74	1,084	$1.61	$1,744	14 175 Watt Lamp (211 Watt Total)	1,084	$1.84	$1,994	$250	
15 250 Watt Lamp (295 Watt Total)	103	0	$1.61	$0	15 250 Watt Lamp (295 Watt Total)	0	$1.84	$0	$0	
16 400 Watt Lamp (468 Watt Total)	164	0	$1.61	$0	16 400 Watt Lamp (468 Watt Total)	0	$1.84	$0	$0	
17 700 Watt Lamp (803 Watt Total)	281	0	$1.61	$0	17 700 Watt Lamp (803 Watt Total)	0	$1.84	$0	$0	
18 1000 Watt Lamp (1135 Watt Total)	397	0	$1.61	$0	18 1000 Watt Lamp (1135 Watt Total)	0	$1.84	$0	$0	
Customer Lighting Fixture Charges					Customer Lighting Fixture Charges					
19 100 Watt Lamp (121 Watt Total)	42	492	$0.82	$403	19 100 Watt Lamp (121 Watt Total)	492	$0.94	$462	$59	
20 175 Watt Lamp (211 Watt Total)	74	18	$0.82	$15	20 175 Watt Lamp (211 Watt Total)	18	$0.94	$17	$2	
21 250 Watt Lamp (295 Watt Total)	103	48	$0.82	$39	21 250 Watt Lamp (295 Watt Total)	48	$0.94	$45	$6	
22 400 Watt Lamp (468 Watt Total)	164	174	$0.82	$143	22 400 Watt Lamp (468 Watt Total)	174	$0.94	$164	$21	
23 700 Watt Lamp (803 Watt Total)	281	0	$0.82	$0	23 700 Watt Lamp (803 Watt Total)	0	$0.94	$0	$0	
24 1000 Watt Lamp (1135 Watt Total)	397	0	$0.82	$0	24 1000 Watt Lamp (1135 Watt Total)	0	$0.94	$0	$0	
25 Total Fixture Charges		477,608		$1,990,466	25 Total Fixture Charges	477,608		$2,276,808	$286,342	14.4%
Miscellaneous Charges					Miscellaneous Charges					
26 Pole Charge		3,156	$8.10	$25,564	26 Pole Charge	3,156	$9.27	$29,256	$3,692	
27 Fixture Service		288	$0.79	$228	27 Fixture Service	288	$0.90	$259	$31	
28 Total Miscellaneous Charges		3,444		$25,792	28 Total Miscellaneous Charges	3,444		$29,515	$3,723	14.4%
NGC per kWh Charges					NGC per kWh Charges					
29 Summer kWh		7,228,809	-$0.000219	-$1,583	29 Summer kWh	7,228,809	-$0.000219	-$1,583	$0	0.0%
30 Winter kWh		14,025,689	-$0.000219	-$3,072	30 Winter kWh	14,025,689	-$0.000219	-$3,072	$0	0.0%
31 Total NGC Charges		21,254,497		-$4,655	31 Total NGC Charges	21,254,497		-$4,655	$0	0.0%
SBC per kWh Charges					SBC per kWh Charges					
32 All kWh		21,254,497	$0.008378	$178,070	32 All kWh	21,254,497	$0.008378	$178,070	$0	0.0%
Distribution per kWh Charges					Distribution per kWh Charges					
33 Seasonal Distr. Charge {3}		0	$0.046926	$0	33 Seasonal Distr. Charge {3}	0	$0.053716	$0	$0	
34 All kWh		21,254,497	$0.046926	$997,389	34 All kWh	21,254,497	$0.053716	$1,141,707	$144,318	
35 Total Distribition kWh Charges		21,254,497		$997,389	35 All kWh	21,254,497		$1,141,707	$144,318	14.5%
BGS per kWh Charges					BGS per kWh Charges					
36 Summer kWh		7,228,809	$0.054268	$392,293	36 Summer kWh	7,228,809	$0.054268	$392,293	$0	0.0%
37 Winter kWh		14,025,689	$0.054860	$769,449	37 Winter kWh	14,025,689	$0.054860	$769,449	$0	0.0%
38 Total BGS Charges		21,254,497		$1,161,742	38 Total BGS Charges	21,254,497		$1,161,742	$0	0.0%
Transmission per kWh Charges					Transmission per kWh Charges					
39 All kWh		21,254,497	$0.000000	$0	39 All kWh	21,254,497	$0.000000	$0	$0	0.0%
System Control Charges					System Control Charges					
40 All kWh		21,254,497	$0.003911	$83,126	40 All kWh	21,254,497	$0.003911	$83,126	$0	0.0%
RGGI Recovery Charges					RGGI Recovery Charges					
41 All kWh		21,254,497	$0.001451	$30,840	41 All kWh	21,254,497	$0.001451	$30,840	$0	0.0%
Tax Act djustment					Tax Act djustment					
42 All kWh		21,254,497	-$0.001470	-$31,244	42 All kWh	21,254,497	-$0.001470	-$31,244	$0	0.0%
LRAM					LRAM					
43 All kWh		21,254,497	$0.000000	$0	43 All kWh	21,254,497	$0.000000	$0	$0	#DIV/0!
44 Total Charges		21,254,497		$4,431,526	44 Total Charges	21,254,497		$4,865,909	$434,383	9.8%

{1} Rates effective 3/1/2023
{2} Proposed rates effective TBD
{3} Distribution kWh charge applied to kWh that seasonal lights would have used if they continued to operate

Jersey Central Power & Light Company

Based on 2022/2023 6+6 Weather Normalized Billing Determinants (Excludes SUT)

Incandescent Street Lighting Service (ISL)

Description of Charge	Monthly kWh Per Unit	Weather Normalized 2022/2023 6+6 Units (a)	Current Rates {1} (b)	Revenue Based on Current Rates (c) = (a) x (b)	Description of Charge	Weather Normalized 2022/2023 6+6 Units (d)	Proposed Rates {2} (e)	Revenue Based on Proposed Rates (f) = (d) x (e)	Change in Revenue (g) = (f) - (c)	Percentage Change in Revenue (h) = (g) / (c)
Company Lighting Fixture Charges					Company Lighting Fixture Charges					
1 105 Watt Lamp	37	92,440	$1.79	$165,468	1 105 Watt Lamp	92,440	$2.05	$189,503	$24,035	
2 205 Watt Lamp	72	12,720	$1.79	$22,768	2 205 Watt Lamp	12,720	$2.05	$26,075	$3,307	
3 327 Watt Lamp	114	2,832	$1.79	$5,069	3 327 Watt Lamp	2,832	$2.05	$5,806	$737	
4 448 Watt Lamp	157	193	$1.79	$346	4 448 Watt Lamp	193	$2.05	$396	$50	
5 690 Watt Lamp	242	36	$1.79	$64	5 690 Watt Lamp	36	$2.05	$74	$10	
6 860 Watt Lamp	301	0	$1.79	$0	6 860 Watt Lamp	0	$2.05	$0	$0	
7 Seasonal 105 Watt Lamp	0	72	$1.79	$129	7 Seasonal 105 Watt Lamp	72	$2.05	$148	$19	
8 Seasonal 205 Watt Lamp	0	0	$1.79	$0	8 Seasonal 205 Watt Lamp	0	$2.05	$0	$0	
9 Seasonal 327 Watt Lamp	0	0	$1.79	$0	9 Seasonal 327 Watt Lamp	0	$2.05	$0	$0	
10 Seasonal 448 Watt Lamp	0	0	$1.79	$0	10 Seasonal 448 Watt Lamp	0	$2.05	$0	$0	
11 Seasonal 690 Watt Lamp	0	0	$1.79	$0	11 Seasonal 690 Watt Lamp	0	$2.05	$0	$0	
12 Seasonal 860 Watt Lamp	0	0	$1.79	$0	12 Seasonal 860 Watt Lamp	0	$2.05	$0	$0	
13 Fire Alarm/Police Box Lamp	9	144	$1.05	$151	13 Fire Alarm/Police Box Lamp	144	$1.20	$173	$22	
14 Fire Alarm/Police Box Lamp-24 hr.	18	1,020	$0.30	$306	14 Fire Alarm/Police Box Lamp-24 h	1,020	$0.34	$347	$41	
Customer Lighting Fixture Charges					Customer Lighting Fixture Charges					
15 105 Watt Lamp	37	80	$0.82	$65	15 105 Watt Lamp	80	$0.94	$75	$10	
16 205 Watt Lamp	72	48	$0.82	$39	16 205 Watt Lamp	48	$0.94	$45	$6	
17 327 Watt Lamp	114	0	$0.82	$0	17 327 Watt Lamp	0	$0.94	$0	$0	
18 448 Watt Lamp	157	0	$0.82	$0	18 448 Watt Lamp	0	$0.94	$0	$0	
19 690 Watt Lamp	242	12	$0.82	$10	19 690 Watt Lamp	12	$0.94	$11	$1	
20 860 Watt Lamp	301	0	$0.82	$0	20 860 Watt Lamp	0	$0.94	$0	$0	
21 Total Fixture Charges		109,597		$194,415	21 Total Fixture Charges	109,597		$222,653	$28,238	14.5%
Miscellaneous Charges					Miscellaneous Charges					
22 Fixture Service		1,680	$0.97	$1,630	22 Fixture Service	1,680	$1.11	$1,865	$235	14.4%
		111,277								
NGC per kWh Charges					NGC per kWh Charges					
23 Summer kWh		1,578,571	-$0.000219	-$346	23 Summer kWh	1,578,571	-$0.000219	-$346	$0	0.0%
24 Winter kWh		3,154,997	-$0.000219	-$691	24 Winter kWh	3,154,997	-$0.000219	-$691	$0	0.0%
25 Total NGC Charges		4,733,569		-$1,037	25 Total NGC Charges	4,733,569		-$1,037	$0	0.0%
SBC per kWh Charges					SBC per kWh Charges					
26 All kWh		4,733,569	$0.008378	$39,658	26 All kWh	4,733,569	$0.008378	$39,658	$0	0.0%
Distribution per kWh Charges					Distribution per kWh Charges					
27 Seasonal Distr. Charge {3}		2,664	$0.046926	$125	27 Seasonal Distr. Charge {3}	2,664	$0.053716	$143	$18	
28 All kWh		4,733,569	$0.046926	$222,127	28 All kWh	4,733,569	$0.053716	$254,268	$32,141	
29 Total Distribition kWh Charges		4,733,569		$222,252	29 Total Distribition kWh Charges	4,733,569		$254,411	$32,159	14.5%
BGS per kWh Charges					BGS per kWh Charges					
30 Summer kWh		1,578,571	$0.054268	$85,666	30 Summer kWh	1,578,571	$0.054268	$85,666	$0	0.0%
31 Winter kWh		3,154,997	$0.054860	$173,083	31 Winter kWh	3,154,997	$0.054860	$173,083	$0	0.0%
32 Total BGS Charges		4,733,569		$258,749	32 Total BGS Charges	4,733,569		$258,749	$0	0.0%
Transmission per kWh Charges					Transmission per kWh Charges					
33 All kWh		4,733,569	$0.000000	$0	33 All kWh	4,733,569	$0.000000	$0	$0	0.0%
System Control Charges					System Control Charges					
34 All kWh		4,733,569	$0.003911	$18,513	34 All kWh	4,733,569	$0.003911	$18,513	$0	0.0%
RGGI Recovery Charges					RGGI Recovery Charges					
35 All kWh		4,733,569	$0.001451	$6,868	35 All kWh	4,733,569	$0.001451	$6,868	$0	0.0%
Tax Act djustment					Tax Act djustment					
36 All kWh		4,733,569	-$0.001470	-$6,958	36 All kWh	4,733,569	-$0.001470	-$6,958	$0	0.0%
LRAM					LRAM					
37 All kWh		4,733,569	$0.000000	$0	37 All kWh	4,733,569	$0.000000	$0	$0	#DIV/0!
38 Total Charges		4,733,569		$734,090	38 Total Charges	4,733,569		$794,722	$60,632	8.3%

{1} Rates effective 3/1/2023

{2} Proposed rates effective TBD

{3} Distribution kWh charge applied to kWh that seasonal lights would have used if they continued to operate

Jersey Central Power & Light Company

Based on 2022/2023 6+6 Weather Normalized Billing Determinants (Excludes SUT)

LED Street Lighting Service (LED)

Description of Charge	Monthly kWh Per Unit	Weather Normalized 2022/2023 6+6 Units (a)	Current Rates {1} (b)	Revenue Based on Current Rates (c) = (a) x (b)	Description of Charge	Weather Normalized 2022/2023 6+6 Units (d)	Proposed Rates {2} (e)	Revenue Based on Proposed Rates (f) = (d) x (e)	Change in Revenue (g) = (f) - (c)	Percentage Change in Revenue (h) = (g) / (c)
Company Lighting Fixture Charges					Company Lighting Fixture Charges					
1 30 Watt Cobra Head Lamp	11	0	$6.07	$0	1 30 Watt Cobra Head Lamp	0	$6.94	$0	$0	
2 50 Watt Cobra Head Lamp	18	4,554	$6.03	$27,462	2 50 Watt Cobra Head Lamp	4,554	$6.90	$31,425	$3,963	
3 90 Watt Cobra Head Lamp	32	2,588	$6.52	$16,874	3 90 Watt Cobra Head Lamp	2,588	$7.46	$19,306	$2,432	
4 130 Watt Cobra Head Lamp	46	1,844	$7.41	$13,664	4 130 Watt Cobra Head Lamp	1,844	$8.48	$15,637	$1,973	
5 260 Watt Cobra Head Lamp	91	1,888	$9.42	$17,785	5 260 Watt Cobra Head Lamp	1,888	$10.78	$20,353	$2,568	
6 50 Watt Colonial Lamp	18	2,424	$8.67	$21,016	6 50 Watt Colonial Lamp	2,424	$9.92	$24,046	$3,030	
7 90 Watt Colonial Lamp	32	2,720	$10.42	$28,342	7 90 Watt Colonial Lamp	2,720	$11.92	$32,422	$4,080	
8 50 Watt Acorn Lamp	18	480	$15.44	$7,411	8 50 Watt Acorn Lamp	480	$17.66	$8,477	$1,066	
9 90 Watt Acorn Lamp	32	252	$14.91	$3,757	9 90 Watt Acorn Lamp	252	$17.06	$4,299	$542	
		16,750		$136,311		16,750		$155,965	$19,654	14.4%
Miscellaneous Charges					Miscellaneous Charges					
10 Pole Charge		0	$7.45	$0	10 Pole Charge	0	$8.52	$0	$0	0.0%
		16,750						$155,965		
NGC per kWh Charges					NGC per kWh Charges					
11 Summer kWh		199,740	-$0.000219	-$44	11 Summer kWh	199,740	-$0.000219	-$44	$0	0.0%
12 Winter kWh		369,056	-$0.000219	-$81	12 Winter kWh	369,056	-$0.000219	-$81	$0	0.0%
13 Total NGC Charges		568,796		-$125	13 Total NGC Charges	568,796		-$125	$0	0.0%
SBC per kWh Charges					SBC per kWh Charges					
14 All kWh		568,796	$0.008378	$4,765	14 All kWh	568,796	$0.008378	$4,765	$0	0.0%
Distribution per kWh Charges					Distribution per kWh Charges					
15 All kWh		568,796	$0.046926	$26,691	15 All kWh	568,796	$0.053716	$30,553	$3,862	
16 Total Distribition kWh Charges		568,796		$26,691	16 Total Distribition kWh Charges	568,796		$30,553	$3,862	14.5%
BGS per kWh Charges					BGS per kWh Charges					
17 Summer kWh		199,740	$0.054268	$10,839	17 Summer kWh	199,740	$0.054268	$10,839	$0	0.0%
18 Winter kWh		369,056	$0.054860	$20,246	18 Winter kWh	369,056	$0.054860	$20,246	$0	0.0%
19 Total BGS Charges		568,796		$31,085	19 Total BGS Charges	568,796		$31,085	$0	0.0%
Transmission per kWh Charges					Transmission per kWh Charges					
20 All kWh		568,796	$0.000000	$0	20 All kWh	568,796	$0.000000	$0	$0	0.0%
System Control Charges					System Control Charges					
21 All kWh		568,796	$0.003911	$2,225	21 All kWh	568,796	$0.003911	$2,225	$0	0.0%
RGGI Recovery Charges					RGGI Recovery Charges					
22 All kWh		568,796	$0.001451	$825	22 All kWh	568,796	$0.001451	$825	$0	0.0%
Tax Act djustment					Tax Act djustment					
23 All kWh		568,796	-$0.001470	-$836	23 All kWh	568,796	-$0.001470	-$836	$0	0.0%
LRAM					LRAM					
24 All kWh		568,796	$0.000000	$0	24 All kWh	568,796	$0.000000	$0	$0	0.0%
25 Total Charges		568,796		$200,941	25 Total Charges	568,796		$224,457	$23,516	11.7%

{1} Rates effective 3/1/2023

{2} Proposed rates effective TBD

Jersey Central Power & Light Company

Summary - Customer Impact Analysis

Based on 2022/2023 6+6 Weather Normalized Billing Determinants (Includes 6.625% SUT)

Revenue at Proposed Rates Effective TBD

Rate Class	NGC	Distr.	Transmission	SBC	ZEC	RRC	TAA	BGS	Total
RS	-$2,204,881	$480,270,506	$141,018,143	$84,162,371	$39,292,106	$14,576,712	-$2,920,996	$746,229,706	$1,500,423,667
RT/RGT	-$45,748	$9,491,292	$2,925,909	$1,746,239	$815,250	$302,444	-$60,020	$14,566,632	$29,741,998
GS	-$1,520,115	$287,603,208	$97,222,402	$58,024,221	$27,089,230	$10,049,650	-$1,779,964	$484,411,158	$961,099,790
GST	-$103,217	$15,074,810	$6,601,460	$3,939,880	$1,839,375	$682,377	-$93,954	$46,177,047	$74,117,778
GP	-$353,978	$37,720,183	$14,492,366	$14,242,030	$6,649,045	$2,466,684	-$245,552	$158,225,396	$233,196,174
GT	-$371,900	$28,824,148	$13,387,709	$17,116,076	$7,990,824	$2,964,461	-$178,213	$176,966,137	$246,699,242
Lighting	-$26,698	$23,482,370	$0	$1,019,137	$475,796	$176,512	-$178,795	$6,650,558	$31,598,880
Total	-$4,626,537	$882,466,517	$275,647,989	$180,249,954	$84,151,626	$31,218,840	-$5,457,494	$1,633,226,634	$3,076,877,529

Change in Revenue from Current Rates to Proposed Rates Effective TBD

Rate Class	NGC	Distr.	Transmission	SBC	ZEC	RRC	TAA	BGS	Total
RS	$0	$107,365,441	$0	$0	$0	$0	$0	$0	$107,365,441
RT/RGT	$0	$2,120,306	$0	$0	$0	$0	$0	$0	$2,120,306
GS	$0	$66,054,072	$0	$0	$0	$0	$0	$0	$66,054,072
GST	$0	$3,460,223	$0	$0	$0	$0	$0	$0	$3,460,223
GP	$0	$8,665,406	$0	$0	$0	$0	$0	$0	$8,665,406
GT	$0	$6,584,541	$0	$0	$0	$0	$0	$0	$6,584,541
Lighting	$0	$2,957,311	$0	$0	$0	$0	$0	$0	$2,957,311
Total	$0	$197,207,300	$0	$0	$0	$0	$0	$0	$197,207,300

Percentage Change in Revenue from Current Rates to Proposed Rates Effective TBD

Rate Class	NGC	Distr.	Transmission	SBC	ZEC	RRC	TAA	BGS	Total
RS	0.0%	7.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	7.7%
RT/RGT	0.0%	7.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	7.7%
GS	0.0%	7.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	7.4%
GST	0.0%	4.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	4.9%
GP	0.0%	3.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.9%
GT	0.0%	2.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.8%
Lighting	0.0%	10.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	10.3%
Total	0.0%	6.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	6.8%

Jersey Central Power & Light Company

Residential Service (RS) - Detailed Customer Impact Analysis

Full Service Charges

Dollar Figures Include 6.625 % Sales & Use Tax

Monthly Usage(kWh) (a)	Current Winter Total Full Service Charges (b)	Proposed Winter Total Full Service Charges (c)	Change in Total Winter Full Service Charges (d) = (c) - (b)	Percentage Change in Total Winter Full Service Charges (e) = (d) / (b)	Current Summer Total Full Service Charges (f)	Proposed Summer Total Full Service Charges (g)	Change in Total Summer Full Service Charges (h) = (g) - (f)	Percentage Change in Total Summer Full Service Charges (i) = (h) / (f)	Current Annual Total Full Service Charges {1} (j)	Proposed Annual Total Full Service Charges {1} (k)	Change in Total Annual Full Service Charges (l) = (k) - (j)	Percentage Change in Total Annual Full Service Charges (m) = (l) / (j)
100	$17.24	$20.29	$3.05	17.7%	$15.10	$17.87	$2.77	18.3%	$198.32	$233.80	$35.48	17.9%
200	$31.23	$34.97	$3.74	12.0%	$26.95	$30.14	$3.19	11.8%	$357.64	$400.32	$42.68	11.9%
300	$45.22	$49.66	$4.44	9.8%	$38.79	$42.42	$3.63	9.4%	$516.92	$566.96	$50.04	9.7%
400	$59.21	$64.34	$5.13	8.7%	$50.64	$54.69	$4.05	8.0%	$676.24	$733.48	$57.24	8.5%
500	$73.20	$79.03	$5.83	8.0%	$62.49	$66.96	$4.47	7.2%	$835.56	$900.08	$64.52	7.7%
600	$87.20	$93.71	$6.51	7.5%	$74.34	$79.23	$4.89	6.6%	$994.96	$1,066.60	$71.64	7.2%
684	**$98.95**	**$106.05**	**$7.10**	**7.2%**	$89.52	$95.82	$6.30	7.0%	$1,149.68	$1,231.68	$82.00	7.1%
700	$101.19	$108.40	$7.21	7.1%	$92.41	$98.98	$6.57	7.1%	$1,179.16	$1,263.12	$83.96	7.1%
800	$115.18	$123.09	$7.91	6.9%	$110.47	$118.72	$8.25	7.5%	$1,363.32	$1,459.60	$96.28	7.1%
900	$129.17	$137.77	$8.60	6.7%	$128.54	$138.47	$9.93	7.7%	$1,547.52	$1,656.04	$108.52	7.0%
973	$139.38	$148.49	$9.11	6.5%	**$141.73**	**$152.88**	**$11.15**	**7.9%**	$1,681.96	$1,799.44	$117.48	7.0%
1,000	$143.16	$152.46	$9.30	6.5%	$146.61	$158.21	$11.60	7.9%	$1,731.72	$1,852.52	$120.80	7.0%
1,100	$157.15	$167.14	$9.99	6.4%	$164.68	$177.96	$13.28	8.1%	$1,915.92	$2,048.96	$133.04	6.9%
1,200	$171.14	$181.83	$10.69	6.2%	$182.74	$197.70	$14.96	8.2%	$2,100.08	$2,245.44	$145.36	6.9%
1,300	$185.13	$196.51	$11.38	6.1%	$200.81	$217.45	$16.64	8.3%	$2,284.28	$2,441.88	$157.60	6.9%
1,400	$199.12	$211.20	$12.08	6.1%	$218.88	$237.19	$18.31	8.4%	$2,468.48	$2,638.36	$169.88	6.9%
1,500	$213.11	$225.89	$12.78	6.0%	$236.94	$256.94	$20.00	8.4%	$2,652.64	$2,834.88	$182.24	6.9%
1,600	$227.10	$240.57	$13.47	5.9%	$255.01	$276.68	$21.67	8.5%	$2,836.84	$3,031.28	$194.44	6.9%
1,700	$241.10	$255.26	$14.16	5.9%	$273.08	$296.43	$23.35	8.6%	$3,021.12	$3,227.80	$206.68	6.8%
1,800	$255.09	$269.94	$14.85	5.8%	$291.15	$316.17	$25.02	8.6%	$3,205.32	$3,424.20	$218.88	6.8%
1,900	$269.08	$284.63	$15.55	5.8%	$309.21	$335.92	$26.71	8.6%	$3,389.48	$3,620.72	$231.24	6.8%
2,000	$283.07	$299.31	$16.24	5.7%	$327.28	$355.66	$28.38	8.7%	$3,573.68	$3,817.12	$243.44	6.8%
2,100	$297.06	$314.00	$16.94	5.7%	$345.35	$375.40	$30.05	8.7%	$3,757.88	$4,013.60	$255.72	6.8%
2,200	$311.05	$328.69	$17.64	5.7%	$363.41	$395.15	$31.74	8.7%	$3,942.04	$4,210.12	$268.08	6.8%
2,300	$325.04	$343.37	$18.33	5.6%	$381.48	$414.89	$33.41	8.8%	$4,126.24	$4,406.52	$280.28	6.8%
2,400	$339.03	$358.06	$19.03	5.6%	$399.55	$434.64	$35.09	8.8%	$4,310.44	$4,603.04	$292.60	6.8%
2,500	$353.02	$372.74	$19.72	5.6%	$417.62	$454.38	$36.76	8.8%	$4,494.64	$4,799.44	$304.80	6.8%
2,600	$367.01	$387.43	$20.42	5.6%	$435.68	$474.13	$38.45	8.8%	$4,678.80	$4,995.96	$317.16	6.8%
2,700	$381.00	$402.11	$21.11	5.5%	$453.75	$493.87	$40.12	8.8%	$4,863.00	$5,192.36	$329.36	6.8%
2,800	$395.00	$416.80	$21.80	5.5%	$471.82	$513.62	$41.80	8.9%	$5,047.28	$5,388.88	$341.60	6.8%
2,900	$408.99	$431.49	$22.50	5.5%	$489.88	$533.36	$43.48	8.9%	$5,231.44	$5,585.36	$353.92	6.8%
3,000	$422.98	$446.17	$23.19	5.5%	$507.95	$553.11	$45.16	8.9%	$5,415.64	$5,781.80	$366.16	6.8%
3,100	$436.97	$460.86	$23.89	5.5%	$526.02	$572.85	$46.83	8.9%	$5,599.84	$5,978.28	$378.44	6.8%
3,200	$450.96	$475.54	$24.58	5.5%	$544.09	$592.60	$48.51	8.9%	$5,784.04	$6,174.72	$390.68	6.8%
3,300	$464.95	$490.23	$25.28	5.4%	$562.15	$612.34	$50.19	8.9%	$5,968.20	$6,371.20	$403.00	6.8%
3,400	$478.94	$504.91	$25.97	5.4%	$580.22	$632.09	$51.87	8.9%	$6,152.40	$6,567.64	$415.24	6.7%
3,500	$492.93	$519.60	$26.67	5.4%	$598.29	$651.83	$53.54	8.9%	$6,336.60	$6,764.12	$427.52	6.7%
3,600	$506.92	$534.29	$27.37	5.4%	$616.36	$671.58	$55.22	9.0%	$6,520.80	$6,960.64	$439.84	6.7%
3,700	$520.91	$548.97	$28.06	5.4%	$634.42	$691.32	$56.90	9.0%	$6,704.96	$7,157.04	$452.08	6.7%
3,800	$534.90	$563.66	$28.76	5.4%	$652.49	$711.06	$58.57	9.0%	$6,889.16	$7,353.52	$464.36	6.7%
3,900	$548.90	$578.34	$29.44	5.4%	$670.56	$730.81	$60.25	9.0%	$7,073.44	$7,549.96	$476.52	6.7%
4,000	$562.89	$593.03	$30.14	5.4%	$688.62	$750.55	$61.93	9.0%	$7,257.60	$7,746.44	$488.84	6.7%
4,100	$576.88	$607.71	$30.83	5.3%	$706.69	$770.30	$63.61	9.0%	$7,441.80	$7,942.88	$501.08	6.7%
4,200	$590.87	$622.40	$31.53	5.3%	$724.76	$790.04	$65.28	9.0%	$7,626.00	$8,139.36	$513.36	6.7%
4,300	$604.86	$637.09	$32.23	5.3%	$742.83	$809.79	$66.96	9.0%	$7,810.20	$8,335.88	$525.68	6.7%
4,400	$618.85	$651.77	$32.92	5.3%	$760.89	$829.53	$68.64	9.0%	$7,994.36	$8,532.28	$537.92	6.7%
4,500	$632.84	$666.46	$33.62	5.3%	$778.96	$849.28	$70.32	9.0%	$8,178.56	$8,728.80	$550.24	6.7%
4,600	$646.83	$681.14	$34.31	5.3%	$797.03	$869.02	$71.99	9.0%	$8,362.76	$8,925.20	$562.44	6.7%
4,700	$660.82	$695.83	$35.01	5.3%	$815.09	$888.77	$73.68	9.0%	$8,546.92	$9,121.72	$574.80	6.7%
4,800	$674.81	$710.51	$35.70	5.3%	$833.16	$908.51	$75.35	9.0%	$8,731.12	$9,318.12	$587.00	6.7%
4,900	$688.80	$725.20	$36.40	5.3%	$851.23	$928.26	$77.03	9.0%	$8,915.32	$9,514.64	$599.32	6.7%
5,000	$702.80	$739.89	$37.09	5.3%	$869.30	$948.00	$78.70	9.1%	$9,099.60	$9,711.12	$611.52	6.7%

Average Winter Usage

Average Summer Usage

{1} Annual Charges equals 8 months of winter charges and 4 months of summer charges.

Jersey Central Power & Light Company

Residential Time-of-Day Service (RT) - Detailed Customer Impact Analysis

Full Service Charges

Dollar Figures Include 6.625 % Sales & Use Tax

Monthly Usage(kWh) (a)	Current Winter Total Full Service Charges (b)	Proposed Winter Total Full Service Charges (c)	Change in Total Winter Full Service Charges (d) = (c) - (b)	Percentage Change in Total Winter Full Service Charges (e) = (d) / (b)	Current Summer Total Full Service Charges (f)	Proposed Summer Total Full Service Charges (g)	Change in Total Summer Full Service Charges (h) = (g) - (f)	Percentage Change in Total Summer Full Service Charges (i) = (h) / (f)	Current Annual Total Full Service Charges {1} (j)	Proposed Annual Total Full Service Charges {1} (k)	Change in Total Annual Full Service Charges (l) = (k) - (j)	Percentage Change in Total Annual Full Service Charges (m) = (l) / (j)
100	$20.30	$23.18	$2.88	14.2%	$21.01	$24.08	$3.07	14.6%	$246.44	$281.76	$35.32	14.3%
200	$33.56	$37.29	$3.73	11.1%	$34.97	$39.09	$4.12	11.8%	$408.36	$454.68	$46.32	11.3%
300	$46.81	$51.40	$4.59	9.8%	$48.93	$54.10	$5.17	10.6%	$570.20	$627.60	$57.40	10.1%
400	$60.07	$65.51	$5.44	9.1%	$62.89	$69.11	$6.22	9.9%	$732.12	$800.52	$68.40	9.3%
500	$73.32	$79.62	$6.30	8.6%	$76.85	$84.12	$7.27	9.5%	$893.96	$973.44	$79.48	8.9%
600	$86.58	$93.73	$7.15	8.3%	$90.81	$99.13	$8.32	9.2%	$1,055.88	$1,146.36	$90.48	8.6%
700	$99.83	$107.84	$8.01	8.0%	$104.77	$114.13	$9.36	8.9%	$1,217.72	$1,319.24	$101.52	8.3%
800	$113.09	$121.95	$8.86	7.8%	$118.73	$129.14	$10.41	8.8%	$1,379.64	$1,492.16	$112.52	8.2%
900	$126.34	$136.06	$9.72	7.7%	$132.69	$144.15	$11.46	8.6%	$1,541.48	$1,665.08	$123.60	8.0%
1,000	$139.60	$150.17	$10.57	7.6%	$146.65	$159.16	$12.51	8.5%	$1,703.40	$1,838.00	$134.60	7.9%
1,041	$145.02	$155.95	$10.93	7.5%	**$152.36**	**$165.30**	**$12.94**	**8.5%**	$1,769.60	$1,908.80	$139.20	7.9%
1,127	**$156.39**	**$168.05**	**$11.66**	**7.5%**	$164.34	$178.18	$13.84	8.4%	$1,908.48	$2,057.12	$148.64	7.8%
1,100	$152.85	$164.28	$11.43	7.5%	$160.61	$174.17	$13.56	8.4%	$1,865.24	$2,010.92	$145.68	7.8%
1,200	$166.11	$178.39	$12.28	7.4%	$174.57	$189.18	$14.61	8.4%	$2,027.16	$2,183.84	$156.68	7.7%
1,300	$179.36	$192.51	$13.15	7.3%	$188.53	$204.19	$15.66	8.3%	$2,189.00	$2,356.84	$167.84	7.7%
1,400	$192.62	$206.62	$14.00	7.3%	$202.49	$219.20	$16.71	8.3%	$2,350.92	$2,529.76	$178.84	7.6%
1,500	$205.87	$220.73	$14.86	7.2%	$216.45	$234.21	$17.76	8.2%	$2,512.76	$2,702.68	$189.92	7.6%
1,600	$219.12	$234.84	$15.72	7.2%	$230.41	$249.22	$18.81	8.2%	$2,674.60	$2,875.60	$201.00	7.5%
1,700	$232.38	$248.95	$16.57	7.1%	$244.37	$264.23	$19.86	8.1%	$2,836.52	$3,048.52	$212.00	7.5%
1,800	$245.63	$263.06	$17.43	7.1%	$258.33	$279.24	$20.91	8.1%	$2,998.36	$3,221.44	$223.08	7.4%
1,900	$258.89	$277.17	$18.28	7.1%	$272.29	$294.25	$21.96	8.1%	$3,160.28	$3,394.36	$234.08	7.4%
2,000	$272.14	$291.28	$19.14	7.0%	$286.25	$309.25	$23.00	8.0%	$3,322.12	$3,567.24	$245.12	7.4%
2,100	$285.40	$305.39	$19.99	7.0%	$300.21	$324.26	$24.05	8.0%	$3,484.04	$3,740.16	$256.12	7.4%
2,200	$298.65	$319.50	$20.85	7.0%	$314.17	$339.27	$25.10	8.0%	$3,645.88	$3,913.08	$267.20	7.3%
2,300	$311.91	$333.61	$21.70	7.0%	$328.13	$354.28	$26.15	8.0%	$3,807.80	$4,086.00	$278.20	7.3%
2,400	$325.16	$347.72	$22.56	6.9%	$342.09	$369.29	$27.20	8.0%	$3,969.64	$4,258.92	$289.28	7.3%
2,500	$338.42	$361.83	$23.41	6.9%	$356.05	$384.30	$28.25	7.9%	$4,131.56	$4,431.84	$300.28	7.3%
2,600	$351.67	$375.94	$24.27	6.9%	$370.01	$399.31	$29.30	7.9%	$4,293.40	$4,604.76	$311.36	7.3%
2,700	$364.93	$390.05	$25.12	6.9%	$383.97	$414.32	$30.35	7.9%	$4,455.32	$4,777.68	$322.36	7.2%
2,800	$378.18	$404.16	$25.98	6.9%	$397.94	$429.33	$31.39	7.9%	$4,617.20	$4,950.60	$333.40	7.2%
2,900	$391.43	$418.27	$26.84	6.9%	$411.90	$444.34	$32.44	7.9%	$4,779.04	$5,123.52	$344.48	7.2%
3,000	$404.69	$432.38	$27.69	6.8%	$425.86	$459.35	$33.49	7.9%	$4,940.96	$5,296.44	$355.48	7.2%
3,100	$417.94	$446.49	$28.55	6.8%	$439.82	$474.36	$34.54	7.9%	$5,102.80	$5,469.36	$366.56	7.2%
3,200	$431.20	$460.60	$29.40	6.8%	$453.78	$489.37	$35.59	7.8%	$5,264.72	$5,642.28	$377.56	7.2%
3,300	$444.45	$474.71	$30.26	6.8%	$467.74	$504.37	$36.63	7.8%	$5,426.56	$5,815.16	$388.60	7.2%
3,400	$457.71	$488.82	$31.11	6.8%	$481.70	$519.38	$37.68	7.8%	$5,588.48	$5,988.08	$399.60	7.2%
3,500	$470.96	$502.93	$31.97	6.8%	$495.66	$534.39	$38.73	7.8%	$5,750.32	$6,161.00	$410.68	7.1%
3,600	$484.22	$517.04	$32.82	6.8%	$509.62	$549.40	$39.78	7.8%	$5,912.24	$6,333.92	$421.68	7.1%
3,700	$497.47	$531.15	$33.68	6.8%	$523.58	$564.41	$40.83	7.8%	$6,074.08	$6,506.84	$432.76	7.1%
3,800	$510.73	$545.27	$34.54	6.8%	$537.54	$579.42	$41.88	7.8%	$6,236.00	$6,679.84	$443.84	7.1%
3,900	$523.98	$559.38	$35.40	6.8%	$551.50	$594.43	$42.93	7.8%	$6,397.84	$6,852.76	$454.92	7.1%
4,000	$537.24	$573.49	$36.25	6.7%	$565.46	$609.44	$43.98	7.8%	$6,559.76	$7,025.68	$465.92	7.1%
4,100	$550.49	$587.60	$37.11	6.7%	$579.42	$624.45	$45.03	7.8%	$6,721.60	$7,198.60	$477.00	7.1%
4,200	$563.75	$601.71	$37.96	6.7%	$593.38	$639.46	$46.08	7.8%	$6,883.52	$7,371.52	$488.00	7.1%
4,300	$577.00	$615.82	$38.82	6.7%	$607.34	$654.47	$47.13	7.8%	$7,045.36	$7,544.44	$499.08	7.1%
4,400	$590.25	$629.93	$39.68	6.7%	$621.30	$669.48	$48.18	7.8%	$7,207.20	$7,717.36	$510.16	7.1%
4,500	$603.51	$644.04	$40.53	6.7%	$635.26	$684.49	$49.23	7.7%	$7,369.12	$7,890.28	$521.16	7.1%
4,600	$616.76	$658.15	$41.39	6.7%	$649.22	$699.49	$50.27	7.7%	$7,530.96	$8,063.16	$532.20	7.1%
4,700	$630.02	$672.26	$42.24	6.7%	$663.18	$714.50	$51.32	7.7%	$7,692.88	$8,236.08	$543.20	7.1%
4,800	$643.27	$686.37	$43.10	6.7%	$677.14	$729.51	$52.37	7.7%	$7,854.72	$8,409.00	$554.28	7.1%
4,900	$656.53	$700.48	$43.95	6.7%	$691.10	$744.52	$53.42	7.7%	$8,016.64	$8,581.92	$565.28	7.1%
5,000	$669.78	$714.59	$44.81	6.7%	$705.06	$759.53	$54.47	7.7%	$8,178.48	$8,754.84	$576.36	7.0%
	Average Winter Usage				**Average Summer Usage**							

{1} Annual Charges equals 8 months of winter charges and 4 months of summer charges.

Jersey Central Power & Light Company

Residential Geothermal & Heat Pump Service (RGT) - Detailed Customer Impact Analysis
Full Service Charges

Dollar Figures Include 6.625 % Sales & Use Tax

Monthly Usage(kWh) (a)	Current Winter Total Full Service Charges (b)	Proposed Winter Total Full Service Charges (c)	Change in Total Winter Full Service Charges (d) = (c) - (b)	Percentage Change in Total Winter Full Service Charges (e) = (d) / (b)	Current Summer Total Full Service Charges (f)	Proposed Summer Total Full Service Charges (g)	Change in Total Summer Full Service Charges (h) = (g) - (f)	Percentage Change in Total Summer Full Service Charges (i) = (h) / (f)	Current Annual Total Full Service Charges {1} (j)	Proposed Annual Total Full Service Charges {1} (k)	Change in Total Annual Full Service Charges (l) = (k) - (j)	Percentage Change in Total Annual Full Service Charges (m) = (l) / (j)
100	$21.04	$23.76	$2.72	12.9%	$21.00	$24.07	$3.07	14.6%	$252.32	$286.36	$34.04	13.5%
200	$35.03	$38.44	$3.41	9.7%	$34.95	$39.07	$4.12	11.8%	$420.04	$463.80	$43.76	10.4%
300	$49.02	$53.13	$4.11	8.4%	$48.90	$54.06	$5.16	10.6%	$587.76	$641.28	$53.52	9.1%
400	$63.01	$67.81	$4.80	7.6%	$62.85	$69.06	$6.21	9.9%	$755.48	$818.72	$63.24	8.4%
500	$77.01	$82.50	$5.49	7.1%	$76.80	$84.06	$7.26	9.5%	$923.28	$996.24	$72.96	7.9%
600	$91.00	$97.19	$6.19	6.8%	$90.75	$99.06	$8.31	9.2%	$1,091.00	$1,173.76	$82.76	7.6%
700	$104.99	$111.87	$6.88	6.6%	$104.70	$114.05	$9.35	8.9%	$1,258.72	$1,351.16	$92.44	7.3%
800	$118.98	$126.56	$7.58	6.4%	$118.65	$129.05	$10.40	8.8%	$1,426.44	$1,528.68	$102.24	7.2%
900	$132.97	$141.24	$8.27	6.2%	$132.60	$144.05	$11.45	8.6%	$1,594.16	$1,706.12	$111.96	7.0%
1,000	$146.96	$155.93	$8.97	6.1%	$146.55	$159.05	$12.50	8.5%	$1,761.88	$1,883.64	$121.76	6.9%
1,100	$160.95	$170.62	$9.67	6.0%	$160.50	$174.04	$13.54	8.4%	$1,929.60	$2,061.12	$131.52	6.8%
1,200	$174.94	$185.30	$10.36	5.9%	$174.45	$189.04	$14.59	8.4%	$2,097.32	$2,238.56	$141.24	6.7%
1,300	$188.94	$199.99	$11.05	5.8%	$188.40	$204.04	$15.64	8.3%	$2,265.12	$2,416.08	$150.96	6.7%
1,400	$202.93	$214.67	$11.74	5.8%	$202.34	$219.04	$16.70	8.3%	$2,432.80	$2,593.52	$160.72	6.6%
1,500	$216.92	$229.36	$12.44	5.7%	$216.29	$234.03	$17.74	8.2%	$2,600.52	$2,771.00	$170.48	6.6%
1,600	$230.91	$244.05	$13.14	5.7%	$230.24	$249.03	$18.79	8.2%	$2,768.24	$2,948.52	$180.28	6.5%
1,700	$244.90	$258.73	$13.83	5.6%	$244.19	$264.03	$19.84	8.1%	$2,935.96	$3,125.96	$190.00	6.5%
1,800	$258.89	$273.42	$14.53	5.6%	$258.14	$279.03	$20.89	8.1%	$3,103.68	$3,303.48	$199.80	6.4%
1,900	$272.88	$288.10	$15.22	5.6%	$272.09	$294.02	$21.93	8.1%	$3,271.40	$3,480.88	$209.48	6.4%
2,291	$327.60	$345.54	$17.94	5.5%	**$326.65**	**$352.68**	**$26.03**	**8.0%**	$3,927.40	$4,175.04	$247.64	6.3%
2,000	$286.87	$302.79	$15.92	5.5%	$286.04	$309.02	$22.98	8.0%	$3,439.12	$3,658.40	$219.28	6.4%
2,100	$300.87	$317.48	$16.61	5.5%	$299.99	$324.02	$24.03	8.0%	$3,606.92	$3,835.92	$229.00	6.3%
2,200	$314.86	$332.16	$17.30	5.5%	$313.94	$339.02	$25.08	8.0%	$3,774.64	$4,013.36	$238.72	6.3%
2,613	**$372.64**	**$392.82**	**$20.18**	**5.4%**	$371.55	$400.96	$29.41	7.9%	$4,467.32	$4,746.40	$279.08	6.2%
2,300	$328.85	$346.85	$18.00	5.5%	$327.89	$354.01	$26.12	8.0%	$3,942.36	$4,190.84	$248.48	6.3%
2,400	$342.84	$361.53	$18.69	5.5%	$341.84	$369.01	$27.17	7.9%	$4,110.08	$4,368.28	$258.20	6.3%
2,500	$356.83	$376.22	$19.39	5.4%	$355.79	$384.01	$28.22	7.9%	$4,277.80	$4,545.80	$268.00	6.3%
2,600	$370.82	$390.91	$20.09	5.4%	$369.74	$399.01	$29.27	7.9%	$4,445.52	$4,723.32	$277.80	6.2%
2,700	$384.81	$405.59	$20.78	5.4%	$383.69	$414.00	$30.31	7.9%	$4,613.24	$4,900.72	$287.48	6.2%
2,800	$398.80	$420.28	$21.48	5.4%	$397.64	$429.00	$31.36	7.9%	$4,780.96	$5,078.24	$297.28	6.2%
2,900	$412.79	$434.96	$22.17	5.4%	$411.59	$444.00	$32.41	7.9%	$4,948.68	$5,255.68	$307.00	6.2%
3,000	$426.79	$449.65	$22.86	5.4%	$425.54	$459.00	$33.46	7.9%	$5,116.48	$5,433.20	$316.72	6.2%
3,100	$440.78	$464.34	$23.56	5.3%	$439.49	$473.99	$34.50	7.9%	$5,284.20	$5,610.68	$326.48	6.2%
3,200	$454.77	$479.02	$24.25	5.3%	$453.44	$488.99	$35.55	7.8%	$5,451.92	$5,788.12	$336.20	6.2%
3,300	$468.76	$493.71	$24.95	5.3%	$467.39	$503.99	$36.60	7.8%	$5,619.64	$5,965.64	$346.00	6.2%
3,400	$482.75	$508.39	$25.64	5.3%	$481.34	$518.99	$37.65	7.8%	$5,787.36	$6,143.08	$355.72	6.1%
3,500	$496.74	$523.08	$26.34	5.3%	$495.29	$533.98	$38.69	7.8%	$5,955.08	$6,320.56	$365.48	6.1%
3,600	$510.73	$537.77	$27.04	5.3%	$509.24	$548.98	$39.74	7.8%	$6,122.80	$6,498.08	$375.28	6.1%
3,700	$524.72	$552.45	$27.73	5.3%	$523.19	$563.98	$40.79	7.8%	$6,290.52	$6,675.52	$385.00	6.1%
3,800	$538.72	$567.14	$28.42	5.3%	$537.14	$578.98	$41.84	7.8%	$6,458.32	$6,853.04	$394.72	6.1%
3,900	$552.71	$581.82	$29.11	5.3%	$551.09	$593.97	$42.88	7.8%	$6,626.04	$7,030.44	$404.40	6.1%
4,000	$566.70	$596.51	$29.81	5.3%	$565.04	$608.97	$43.93	7.8%	$6,793.76	$7,207.96	$414.20	6.1%
4,100	$580.69	$611.20	$30.51	5.3%	$578.98	$623.97	$44.99	7.8%	$6,961.44	$7,385.48	$424.04	6.1%
4,200	$594.68	$625.88	$31.20	5.2%	$592.93	$638.97	$46.04	7.8%	$7,129.16	$7,562.92	$433.76	6.1%
4,300	$608.67	$640.57	$31.90	5.2%	$606.88	$653.97	$47.09	7.8%	$7,296.88	$7,740.44	$443.56	6.1%
4,400	$622.66	$655.25	$32.59	5.2%	$620.83	$668.96	$48.13	7.8%	$7,464.60	$7,917.84	$453.24	6.1%
4,500	$636.65	$669.94	$33.29	5.2%	$634.78	$683.96	$49.18	7.7%	$7,632.32	$8,095.36	$463.04	6.1%
4,600	$650.65	$684.63	$33.98	5.2%	$648.73	$698.96	$50.23	7.7%	$7,800.12	$8,272.88	$472.76	6.1%
4,700	$664.64	$699.31	$34.67	5.2%	$662.68	$713.96	$51.28	7.7%	$7,967.84	$8,450.32	$482.48	6.1%
4,800	$678.63	$714.00	$35.37	5.2%	$676.63	$728.95	$52.32	7.7%	$8,135.56	$8,627.80	$492.24	6.1%
4,900	$692.62	$728.68	$36.06	5.2%	$690.58	$743.95	$53.37	7.7%	$8,303.28	$8,805.24	$501.96	6.0%
5,000	$706.61	$743.37	$36.76	5.2%	$704.53	$758.95	$54.42	7.7%	$8,471.00	$8,982.76	$511.76	6.0%
	Average Winter Usage				**Average Summer Usage**							

{1} Annual Charges equals 8 months of winter charges and 4 months of summer charges.

Jersey Central Power & Light Company

General Service Secondary (GS) - Detailed Customer Impact Analysis

Full Service Charges

Dollar Figures Include 6.625 % Sales & Use Tax

Monthly Usage(kWh) (a)	Current Winter Total Full Service Charges (b)	Proposed Winter Total Full Service Charges (c)	Change in Total Winter Full Service Charges (d) = (c) - (b)	Percentage Change in Total Winter Full Service Charges (e) = (d) / (b)	Current Summer Total Full Service Charges (f)	Proposed Summer Total Full Service Charges (g)	Change in Total Summer Full Service Charges (h) = (g) - (f)	Percentage Change in Total Summer Full Service Charges (i) = (h) / (f)	Current Annual Total Full Service Charges {1} (j)	Proposed Annual Total Full Service Charges {1} (k)	Change in Total Annual Full Service Charges (l) = (k) - (j)	Percentage Change in Total Annual Full Service Charges (m) = (l) / (j)
50	$12.34	$14.48	$2.14	17.3%	$12.60	$14.81	$2.21	17.5%	$149.12	$175.08	$25.96	17.4%
100	$20.59	$23.64	$3.05	14.8%	$21.11	$24.31	$3.20	15.2%	$249.16	$286.36	$37.20	14.9%
200	$37.08	$41.97	$4.89	13.2%	$38.13	$43.31	$5.18	13.6%	$449.16	$509.00	$59.84	13.3%
300	$53.58	$60.30	$6.72	12.5%	$55.15	$62.32	$7.17	13.0%	$649.24	$731.68	$82.44	12.7%
400	$70.08	$78.63	$8.55	12.2%	$72.17	$81.32	$9.15	12.7%	$849.32	$954.32	$105.00	12.4%
500	$86.58	$96.96	$10.38	12.0%	$89.20	$100.32	$11.12	12.5%	$1,049.44	$1,176.96	$127.52	12.2%
600	$103.07	$115.29	$12.22	11.9%	$106.22	$119.32	$13.10	12.3%	$1,249.44	$1,399.60	$150.16	12.0%
700	$119.57	$133.62	$14.05	11.8%	$123.24	$138.32	$15.08	12.2%	$1,449.52	$1,622.24	$172.72	11.9%
800	$136.07	$151.95	$15.88	11.7%	$140.26	$157.33	$17.07	12.2%	$1,649.60	$1,844.92	$195.32	11.8%
900	$152.57	$170.28	$17.71	11.6%	$157.28	$176.33	$19.05	12.1%	$1,849.68	$2,067.56	$217.88	11.8%
1,000	$169.06	$188.61	$19.55	11.6%	$174.30	$195.33	$21.03	12.1%	$2,049.68	$2,290.20	$240.52	11.7%
1,100	$179.95	$199.66	$19.71	11.0%	$185.22	$206.40	$21.18	11.4%	$2,180.48	$2,422.88	$242.40	11.1%
1,200	$190.84	$210.70	$19.86	10.4%	$196.13	$217.48	$21.35	10.9%	$2,311.24	$2,555.52	$244.28	10.6%
1,300	$201.73	$221.75	$20.02	9.9%	$207.05	$228.55	$21.50	10.4%	$2,442.04	$2,688.20	$246.16	10.1%
1,400	$212.62	$232.80	$20.18	9.5%	$217.97	$239.63	$21.66	9.9%	$2,572.84	$2,820.92	$248.08	9.6%
1,500	$223.50	$243.84	$20.34	9.1%	$228.88	$250.70	$21.82	9.5%	$2,703.52	$2,953.52	$250.00	9.2%
1,600	$234.39	$254.89	$20.50	8.7%	$239.80	$261.78	$21.98	9.2%	$2,834.32	$3,086.24	$251.92	8.9%
1,700	$245.28	$265.94	$20.66	8.4%	$250.71	$272.85	$22.14	8.8%	$2,965.08	$3,218.92	$253.84	8.6%
1,800	$256.17	$276.98	$20.81	8.1%	$261.63	$283.93	$22.30	8.5%	$3,095.88	$3,351.56	$255.68	8.3%
1,900	$267.06	$288.03	$20.97	7.9%	$272.55	$295.00	$22.45	8.2%	$3,226.68	$3,484.24	$257.56	8.0%
2,000	$277.94	$299.08	$21.14	7.6%	$283.46	$306.07	$22.61	8.0%	$3,357.36	$3,616.92	$259.56	7.7%
2,100	$288.83	$310.12	$21.29	7.4%	$294.38	$317.15	$22.77	7.7%	$3,488.16	$3,749.56	$261.40	7.5%
2,200	$299.72	$321.17	$21.45	7.2%	$305.29	$328.22	$22.93	7.5%	$3,618.92	$3,882.24	$263.32	7.3%
2,300	$310.61	$332.22	$21.61	7.0%	$316.21	$339.30	$23.09	7.3%	$3,749.72	$4,014.96	$265.24	7.1%
2,400	$321.50	$343.26	$21.76	6.8%	$327.13	$350.37	$23.24	7.1%	$3,880.52	$4,147.56	$267.04	6.9%
2,500	$332.38	$354.31	$21.93	6.6%	$338.04	$361.45	$23.41	6.9%	$4,011.20	$4,280.28	$269.08	6.7%
2,600	$343.27	$365.35	$22.08	6.4%	$348.96	$372.52	$23.56	6.8%	$4,142.00	$4,412.88	$270.88	6.5%
2,700	$354.16	$376.40	$22.24	6.3%	$359.87	$383.59	$23.72	6.6%	$4,272.76	$4,545.56	$272.80	6.4%
2,800	$365.05	$387.45	$22.40	6.1%	$370.79	$394.67	$23.88	6.4%	$4,403.56	$4,678.28	$274.72	6.2%
2,900	$375.94	$398.49	$22.55	6.0%	$381.71	$405.74	$24.03	6.3%	$4,534.36	$4,810.88	$276.52	6.1%
3,000	$387.56	$410.50	$22.94	5.9%	$392.62	$416.82	$24.20	6.2%	$4,670.96	$4,951.28	$280.32	6.0%
3,500	$454.54	$482.00	$27.46	6.0%	$459.08	$487.63	$28.55	6.2%	$5,472.64	$5,806.52	$333.88	6.1%
4,000	$521.53	$553.50	$31.97	6.1%	$527.12	$560.49	$33.37	6.3%	$6,280.72	$6,669.96	$389.24	6.2%
3,969	**$516.66**	**$548.14**	**$31.48**	**6.1%**	$522.93	$556.01	$33.08	6.3%	$6,225.00	$6,609.16	$384.16	6.2%
4,500	$587.78	$624.05	$36.27	6.2%	$594.38	$632.32	$37.94	6.4%	$7,079.76	$7,521.68	$441.92	6.2%
4,562	$596.03	$632.83	$36.80	6.2%	**$602.75**	**$641.27**	**$38.52**	**6.4%**	$7,179.24	$7,627.72	$448.48	6.2%
5,000	$654.76	$695.55	$40.79	6.2%	$662.42	$705.20	$42.78	6.5%	$7,887.76	$8,385.20	$497.44	6.3%
6,000	$788.74	$838.54	$49.80	6.3%	$796.92	$848.86	$51.94	6.5%	$9,497.60	$10,103.76	$606.16	6.4%
7,000	$921.97	$980.60	$58.63	6.4%	$932.22	$993.56	$61.34	6.6%	$11,104.64	$11,819.04	$714.40	6.4%
8,000	$1,055.94	$1,123.59	$67.65	6.4%	$1,067.52	$1,138.27	$70.75	6.6%	$12,717.60	$13,541.80	$824.20	6.5%
9,000	$1,189.91	$1,266.59	$76.68	6.4%	$1,202.81	$1,282.96	$80.15	6.7%	$14,330.52	$15,264.56	$934.04	6.5%
10,000	$1,323.15	$1,408.64	$85.49	6.5%	$1,338.11	$1,427.67	$89.56	6.7%	$15,937.64	$16,979.80	$1,042.16	6.5%
15,000	$1,992.27	$2,122.70	$130.43	6.5%	$2,014.59	$2,151.18	$136.59	6.8%	$23,996.52	$25,586.32	$1,589.80	6.6%
20,000	$2,660.65	$2,835.79	$175.14	6.6%	$2,690.28	$2,873.65	$183.37	6.8%	$32,046.32	$34,180.92	$2,134.60	6.7%
25,000	$3,329.04	$3,548.89	$219.85	6.6%	$3,366.76	$3,597.16	$230.40	6.8%	$40,099.36	$42,779.76	$2,680.40	6.7%
30,000	$3,997.42	$4,261.98	$264.56	6.6%	$4,042.44	$4,319.63	$277.19	6.9%	$48,149.12	$51,374.36	$3,225.24	6.7%
35,000	$4,665.81	$4,975.08	$309.27	6.6%	$4,718.92	$5,043.14	$324.22	6.9%	$56,202.16	$59,973.20	$3,771.04	6.7%
40,000	$5,334.19	$5,688.18	$353.99	6.6%	$5,394.61	$5,765.61	$371.00	6.9%	$64,251.96	$68,567.88	$4,315.92	6.7%
45,000	$6,003.31	$6,402.23	$398.92	6.6%	$6,071.09	$6,489.12	$418.03	6.9%	$72,310.84	$77,174.32	$4,863.48	6.7%
50,000	$6,671.70	$7,115.32	$443.62	6.6%	$6,746.78	$7,211.60	$464.82	6.9%	$80,360.72	$85,768.96	$5,408.24	6.7%
	Average Winter Usage				**Average Summer Usage**							

{1} Annual Charges equals 8 months of winter charges and 4 months of summer charges.

Jersey Central Power & Light Company

General Service Secondary Time-of-Day (GST) - Detailed Customer Impact Analysis

Full Service Charges

Dollar Figures Include 6.625 % Sales & Use Tax

Monthly Usage(kWh)	Current Winter Total Full Service Charges	Proposed Winter Total Full Service Charges	Change in Total Winter Full Service Charges	Percentage Change in Total Winter Full Service Charges	Current Summer Total Full Service Charges	Proposed Summer Total Full Service Charges	Change in Total Summer Full Service Charges	Percentage Change in Total Summer Full Service Charges	Current Annual Total Full Service Charges {1}	Proposed Annual Total Full Service Charges {1}	Change in Total Annual Full Service Charges	Percentage Change in Total Annual Full Service Charges
(a)	(b)	(c)	(d) = (c) - (b)	(e) = (d) / (b)	(f)	(g)	(h) = (g) - (f)	(i) = (h) / (f)	(j)	(k)	(l) = (k) - (j)	(m) = (l) / (j)
150,000	$22,177.02	$23,234.17	$1,057.15	4.8%	$27,230.27	$28,474.50	$1,244.23	4.6%	$286,337.24	$299,771.36	$13,434.12	4.7%
160,000	$23,651.94	$24,778.50	$1,126.56	4.8%	$29,042.24	$30,368.41	$1,326.17	4.6%	$305,384.48	$319,701.64	$14,317.16	4.7%
170,000	$25,126.87	$26,322.84	$1,195.97	4.8%	$30,854.21	$32,262.32	$1,408.11	4.6%	$324,431.80	$339,632.00	$15,200.20	4.7%
180,000	$26,601.80	$27,867.18	$1,265.38	4.8%	$32,666.17	$34,156.22	$1,490.05	4.6%	$343,479.08	$359,562.32	$16,083.24	4.7%
190,000	$28,076.73	$29,411.52	$1,334.79	4.8%	$34,478.15	$36,050.14	$1,571.99	4.6%	$362,526.44	$379,492.72	$16,966.28	4.7%
200,000	$29,552.44	$30,956.93	$1,404.49	4.8%	$36,290.11	$37,944.04	$1,653.93	4.6%	$381,579.96	$399,431.60	$17,851.64	4.7%
210,000	$31,027.37	$32,501.27	$1,473.90	4.8%	$38,102.08	$39,837.95	$1,735.87	4.6%	$400,627.28	$419,361.96	$18,734.68	4.7%
220,000	$32,502.30	$34,045.61	$1,543.31	4.7%	$39,914.05	$41,731.86	$1,817.81	4.6%	$419,674.60	$439,292.32	$19,617.72	4.7%
230,000	$33,977.23	$35,589.95	$1,612.72	4.7%	$41,726.02	$43,625.77	$1,899.75	4.6%	$438,721.92	$459,222.68	$20,500.76	4.7%
194,791	**$28,783.71**	**$30,151.90**	**$1,368.19**	**4.8%**	$35,346.63	$36,958.04	$1,611.41	4.6%	$371,656.20	$389,047.36	$17,391.16	4.7%
240,000	$35,452.16	$37,134.29	$1,682.13	4.7%	$43,537.99	$45,519.68	$1,981.69	4.6%	$457,769.24	$479,153.04	$21,383.80	4.7%
250,000	$36,927.09	$38,678.63	$1,751.54	4.7%	$45,349.95	$47,413.58	$2,063.63	4.6%	$476,816.52	$499,083.36	$22,266.84	4.7%
260,000	$38,402.80	$40,224.04	$1,821.24	4.7%	$47,161.92	$49,307.49	$2,145.57	4.5%	$495,870.08	$519,022.28	$23,152.20	4.7%
197,666	$29,207.99	$30,596.22	$1,388.23	4.8%	**$35,866.83**	**$37,501.52**	**$1,634.69**	**4.6%**	$377,131.24	$394,775.84	$17,644.60	4.7%
270,000	$39,877.73	$41,768.38	$1,890.65	4.7%	$48,973.89	$51,201.40	$2,227.51	4.5%	$514,917.40	$538,952.64	$24,035.24	4.7%
280,000	$41,352.65	$43,312.71	$1,960.06	4.7%	$50,785.86	$53,095.31	$2,309.45	4.5%	$533,964.64	$558,882.92	$24,918.28	4.7%
290,000	$42,827.58	$44,857.05	$2,029.47	4.7%	$52,597.83	$54,989.22	$2,391.39	4.5%	$553,011.96	$578,813.28	$25,801.32	4.7%
300,000	$44,302.51	$46,401.39	$2,098.88	4.7%	$54,409.79	$56,883.12	$2,473.33	4.5%	$572,059.24	$598,743.60	$26,684.36	4.7%
310,000	$45,778.22	$47,946.80	$2,168.58	4.7%	$56,221.76	$58,777.03	$2,555.27	4.5%	$591,112.80	$618,682.52	$27,569.72	4.7%
320,000	$47,253.15	$49,491.14	$2,237.99	4.7%	$58,033.73	$60,670.94	$2,637.21	4.5%	$610,160.12	$638,612.88	$28,452.76	4.7%
330,000	$48,728.08	$51,035.48	$2,307.40	4.7%	$59,845.70	$62,564.85	$2,719.15	4.5%	$629,207.44	$658,543.24	$29,335.80	4.7%
340,000	$50,203.00	$52,579.81	$2,376.81	4.7%	$61,657.67	$64,458.76	$2,801.09	4.5%	$648,254.68	$678,473.52	$30,218.84	4.7%
350,000	$51,677.93	$54,124.15	$2,446.22	4.7%	$63,469.64	$66,352.67	$2,883.03	4.5%	$667,302.00	$698,403.88	$31,101.88	4.7%
360,000	$53,152.86	$55,668.49	$2,515.63	4.7%	$65,281.60	$68,246.57	$2,964.97	4.5%	$686,349.28	$718,334.20	$31,984.92	4.7%
370,000	$54,628.57	$57,213.90	$2,585.33	4.7%	$67,093.57	$70,140.48	$3,046.91	4.5%	$705,402.84	$738,273.12	$32,870.28	4.7%
380,000	$56,103.50	$58,758.24	$2,654.74	4.7%	$68,905.54	$72,034.39	$3,128.85	4.5%	$724,450.16	$758,203.48	$33,753.32	4.7%
390,000	$57,578.43	$60,302.58	$2,724.15	4.7%	$70,717.51	$73,928.30	$3,210.79	4.5%	$743,497.48	$778,133.84	$34,636.36	4.7%
400,000	$59,053.35	$61,846.91	$2,793.56	4.7%	$72,529.48	$75,822.21	$3,292.73	4.5%	$762,544.72	$798,064.12	$35,519.40	4.7%
410,000	$60,528.28	$63,391.25	$2,862.97	4.7%	$74,341.44	$77,716.11	$3,374.67	4.5%	$781,592.00	$817,994.44	$36,402.44	4.7%
420,000	$62,003.21	$64,935.59	$2,932.38	4.7%	$76,153.41	$79,610.02	$3,456.61	4.5%	$800,639.32	$837,924.80	$37,285.48	4.7%
430,000	$63,478.92	$66,481.00	$3,002.08	4.7%	$77,965.38	$81,503.93	$3,538.55	4.5%	$819,692.88	$857,863.72	$38,170.84	4.7%
440,000	$64,953.85	$68,025.34	$3,071.49	4.7%	$79,777.35	$83,397.84	$3,620.49	4.5%	$838,740.20	$877,794.08	$39,053.88	4.7%
450,000	$66,428.78	$69,569.68	$3,140.90	4.7%	$81,589.32	$85,291.75	$3,702.43	4.5%	$857,787.52	$897,724.44	$39,936.92	4.7%
460,000	$67,903.70	$71,114.01	$3,210.31	4.7%	$83,401.28	$87,185.65	$3,784.37	4.5%	$876,834.72	$917,654.68	$40,819.96	4.7%
470,000	$69,378.63	$72,658.35	$3,279.72	4.7%	$85,213.26	$89,079.57	$3,866.31	4.5%	$895,882.08	$937,585.08	$41,703.00	4.7%
480,000	$70,854.34	$74,203.76	$3,349.42	4.7%	$87,025.22	$90,973.47	$3,948.25	4.5%	$914,935.60	$957,523.96	$42,588.36	4.7%
490,000	$72,329.27	$75,748.10	$3,418.83	4.7%	$88,837.19	$92,867.38	$4,030.19	4.5%	$933,982.92	$977,454.32	$43,471.40	4.7%
500,000	$73,804.20	$77,292.44	$3,488.24	4.7%	$90,649.16	$94,761.29	$4,112.13	4.5%	$953,030.24	$997,384.68	$44,354.44	4.7%
510,000	$75,279.13	$78,836.78	$3,557.65	4.7%	$92,461.12	$96,655.19	$4,194.07	4.5%	$972,077.52	$1,017,315.00	$45,237.48	4.7%
520,000	$76,754.05	$80,381.11	$3,627.06	4.7%	$94,273.10	$98,549.11	$4,276.01	4.5%	$991,124.80	$1,037,245.32	$46,120.52	4.7%
530,000	$78,228.98	$81,925.45	$3,696.47	4.7%	$96,085.06	$100,443.01	$4,357.95	4.5%	$1,010,172.08	$1,057,175.64	$47,003.56	4.7%
540,000	$79,704.69	$83,470.86	$3,766.17	4.7%	$97,897.03	$102,336.92	$4,439.89	4.5%	$1,029,225.64	$1,077,114.56	$47,888.92	4.7%
550,000	$81,179.62	$85,015.20	$3,835.58	4.7%	$99,709.00	$104,230.83	$4,521.83	4.5%	$1,048,272.96	$1,097,044.92	$48,771.96	4.7%
560,000	$82,654.55	$86,559.54	$3,904.99	4.7%	$101,520.96	$106,124.73	$4,603.77	4.5%	$1,067,320.24	$1,116,975.24	$49,655.00	4.7%
570,000	$84,129.48	$88,103.88	$3,974.40	4.7%	$103,332.94	$108,018.65	$4,685.71	4.5%	$1,086,367.60	$1,136,905.64	$50,538.04	4.7%
580,000	$85,604.40	$89,648.21	$4,043.81	4.7%	$105,144.90	$109,912.55	$4,767.65	4.5%	$1,105,414.80	$1,156,835.88	$51,421.08	4.7%
590,000	$87,080.11	$91,193.62	$4,113.51	4.7%	$106,956.88	$111,806.47	$4,849.59	4.5%	$1,124,468.40	$1,176,774.84	$52,306.44	4.7%
600,000	$88,555.04	$92,737.96	$4,182.92	4.7%	$108,768.84	$113,700.37	$4,931.53	4.5%	$1,143,515.68	$1,196,705.16	$53,189.48	4.7%
	Average Winter Usage				**Average Summer Usage**							

{1} Annual Charges equals 8 months of winter charges and 4 months of summer charges.

Jersey Central Power & Light Company

General Service Primary (GP) - Detailed Customer Impact Analysis

Full Service Charges

Dollar Figures Include 6.625 % Sales & Use Tax

Monthly Usage(kWh) (a)	Current Winter Total Full Service Charges (b)	Proposed Winter Total Full Service Charges (c)	Change in Total Winter Full Service Charges (d) = (c) - (b)	Percentage Change in Total Winter Full Service Charges (e) = (d) / (b)	Current Summer Total Full Service Charges (f)	Proposed Summer Total Full Service Charges (g)	Change in Total Summer Full Service Charges (h) = (g) - (f)	Percentage Change in Total Summer Full Service Charges (i) = (h) / (f)	Current Annual Total Full Service Charges {1} (j)	Proposed Annual Total Full Service Charges {1} (k)	Change in Total Annual Full Service Charges (l) = (k) - (j)	Percentage Change in Total Annual Full Service Charges (m) = (l) / (j)
200,000	$25,093.61	$26,119.34	$1,025.73	4.1%	$32,234.49	$33,394.21	$1,159.72	3.6%	$329,686.84	$342,531.56	$12,844.72	3.9%
210,000	$26,344.77	$27,420.75	$1,075.98	4.1%	$33,842.95	$35,059.72	$1,216.77	3.6%	$346,129.96	$359,604.88	$13,474.92	3.9%
220,000	$27,596.53	$28,722.99	$1,126.46	4.1%	$35,451.43	$36,725.25	$1,273.82	3.6%	$362,577.96	$376,684.92	$14,106.96	3.9%
230,000	$28,847.65	$30,024.34	$1,176.69	4.1%	$37,059.86	$38,390.71	$1,330.85	3.6%	$379,020.64	$393,757.56	$14,736.92	3.9%
240,000	$30,099.42	$31,326.58	$1,227.16	4.1%	$38,668.33	$40,056.23	$1,387.90	3.6%	$395,468.68	$410,837.56	$15,368.88	3.9%
250,000	$31,350.54	$32,627.93	$1,277.39	4.1%	$40,276.76	$41,721.69	$1,444.93	3.6%	$411,911.36	$427,910.20	$15,998.84	3.9%
260,000	$32,602.30	$33,930.17	$1,327.87	4.1%	$41,885.24	$43,387.21	$1,501.97	3.6%	$428,359.36	$444,990.20	$16,630.84	3.9%
270,000	$33,853.42	$35,231.52	$1,378.10	4.1%	$43,493.67	$45,052.67	$1,559.00	3.6%	$444,802.04	$462,062.84	$17,260.80	3.9%
280,000	$35,105.19	$36,533.76	$1,428.57	4.1%	$45,102.14	$46,718.20	$1,616.06	3.6%	$461,250.08	$479,142.88	$17,892.80	3.9%
290,000	$36,356.89	$37,835.94	$1,479.05	4.1%	$46,710.56	$48,383.66	$1,673.10	3.6%	$477,697.36	$496,222.16	$18,524.80	3.9%
300,000	$37,608.87	$39,138.17	$1,529.30	4.1%	$48,320.49	$50,050.88	$1,730.39	3.6%	$494,152.92	$513,308.88	$19,155.96	3.9%
310,000	$38,860.64	$40,440.41	$1,579.77	4.1%	$49,928.97	$51,716.41	$1,787.44	3.6%	$510,601.00	$530,388.92	$19,787.92	3.9%
320,000	$40,111.76	$41,741.76	$1,630.00	4.1%	$51,537.39	$53,381.86	$1,844.47	3.6%	$527,043.64	$547,461.52	$20,417.88	3.9%
330,000	$41,363.52	$43,044.00	$1,680.48	4.1%	$53,145.87	$55,047.39	$1,901.52	3.6%	$543,491.64	$564,541.56	$21,049.92	3.9%
340,000	$42,615.46	$44,346.17	$1,730.71	4.1%	$54,755.12	$56,713.67	$1,958.55	3.6%	$559,944.16	$581,624.04	$21,679.88	3.9%
213,986	**$26,843.88**	**$27,940.00**	**$1,096.12**	**4.1%**	$34,484.00	$35,723.44	$1,239.44	3.6%	$352,687.04	$366,413.76	$13,726.72	3.9%
350,000	$43,867.22	$45,648.40	$1,781.18	4.1%	$56,363.58	$58,379.18	$2,015.60	3.6%	$576,392.08	$598,703.92	$22,311.84	3.9%
360,000	$45,118.35	$46,949.76	$1,831.41	4.1%	$57,972.02	$60,044.65	$2,072.63	3.6%	$592,834.88	$615,776.68	$22,941.80	3.9%
370,000	$46,370.10	$48,251.99	$1,881.89	4.1%	$59,580.49	$61,710.16	$2,129.67	3.6%	$609,282.76	$632,856.56	$23,573.80	3.9%
380,000	$47,621.27	$49,553.41	$1,932.14	4.1%	$61,188.97	$63,375.69	$2,186.72	3.6%	$625,726.04	$649,930.04	$24,204.00	3.9%
390,000	$48,872.99	$50,855.58	$1,982.59	4.1%	$62,797.39	$65,041.15	$2,243.76	3.6%	$642,173.48	$667,009.24	$24,835.76	3.9%
237,388	$29,772.31	$30,986.28	$1,213.97	4.1%	**$38,247.97**	**$39,620.93**	**$1,372.96**	**3.6%**	$391,170.36	$406,373.96	$15,203.60	3.9%
400,000	$50,124.16	$52,157.00	$2,032.84	4.1%	$64,405.87	$66,706.67	$2,300.80	3.6%	$658,616.76	$684,082.68	$25,465.92	3.9%
410,000	$51,375.86	$53,459.18	$2,083.32	4.1%	$66,014.29	$68,372.14	$2,357.85	3.6%	$675,064.04	$701,162.00	$26,097.96	3.9%
420,000	$52,627.84	$54,761.41	$2,133.57	4.1%	$67,624.22	$70,039.36	$2,415.14	3.6%	$691,519.60	$718,248.72	$26,729.12	3.9%
430,000	$53,879.57	$56,063.59	$2,184.02	4.1%	$69,232.65	$71,704.82	$2,472.17	3.6%	$707,967.16	$735,328.00	$27,360.84	3.9%
440,000	$55,131.32	$57,365.82	$2,234.50	4.1%	$70,841.12	$73,370.34	$2,529.22	3.6%	$724,415.04	$752,407.92	$27,992.88	3.9%
450,000	$56,382.49	$58,667.24	$2,284.75	4.1%	$72,449.60	$75,035.87	$2,586.27	3.6%	$740,858.32	$769,481.40	$28,623.08	3.9%
460,000	$57,634.21	$59,969.41	$2,335.20	4.1%	$74,058.02	$76,701.32	$2,643.30	3.6%	$757,305.76	$786,560.56	$29,254.80	3.9%
470,000	$58,885.38	$61,270.83	$2,385.45	4.1%	$75,666.50	$78,366.85	$2,700.35	3.6%	$773,749.04	$803,634.04	$29,885.00	3.9%
480,000	$60,137.09	$62,573.00	$2,435.91	4.1%	$77,274.93	$80,032.30	$2,757.37	3.6%	$790,196.44	$820,713.20	$30,516.76	3.9%
490,000	$61,388.26	$63,874.42	$2,486.16	4.0%	$78,883.41	$81,697.83	$2,814.42	3.6%	$806,639.72	$837,786.68	$31,146.96	3.9%
500,000	$62,639.98	$65,176.59	$2,536.61	4.0%	$80,491.83	$83,363.29	$2,871.46	3.6%	$823,087.16	$854,865.88	$31,778.72	3.9%
510,000	$63,891.15	$66,478.01	$2,586.86	4.0%	$82,100.31	$85,028.81	$2,928.50	3.6%	$839,530.44	$871,939.32	$32,408.88	3.9%
520,000	$65,142.90	$67,780.24	$2,637.34	4.0%	$83,708.78	$86,694.33	$2,985.55	3.6%	$855,978.32	$889,019.24	$33,040.92	3.9%
530,000	$66,394.02	$69,081.61	$2,687.59	4.0%	$85,317.20	$88,359.80	$3,042.60	3.6%	$872,420.96	$906,092.08	$33,671.12	3.9%
540,000	$67,646.60	$70,384.66	$2,738.06	4.0%	$86,927.13	$90,027.02	$3,099.89	3.6%	$888,881.32	$923,185.36	$34,304.04	3.9%
560,000	$70,149.48	$72,988.25	$2,838.77	4.0%	$90,144.04	$93,358.01	$3,213.97	3.6%	$921,772.00	$957,338.04	$35,566.04	3.9%
580,000	$72,653.18	$75,592.65	$2,939.47	4.0%	$93,361.75	$96,689.80	$3,328.05	3.6%	$954,672.44	$991,500.40	$36,827.96	3.9%
600,000	$75,156.06	$78,196.24	$3,040.18	4.0%	$96,578.66	$100,020.78	$3,442.12	3.6%	$987,563.12	$1,025,653.04	$38,089.92	3.9%
620,000	$77,658.95	$80,799.83	$3,140.88	4.0%	$99,795.56	$103,351.76	$3,556.20	3.6%	$1,020,453.84	$1,059,805.68	$39,351.84	3.9%
640,000	$80,161.82	$83,403.43	$3,241.61	4.0%	$103,012.45	$106,682.75	$3,670.30	3.6%	$1,053,344.36	$1,093,958.44	$40,614.08	3.9%
660,000	$82,665.57	$86,007.90	$3,342.33	4.0%	$106,230.86	$110,015.50	$3,784.64	3.6%	$1,086,248.00	$1,128,125.20	$41,877.20	3.9%
680,000	$85,168.45	$88,611.49	$3,443.04	4.0%	$109,447.76	$113,346.48	$3,898.72	3.6%	$1,119,138.64	$1,162,277.84	$43,139.20	3.9%
700,000	$87,671.34	$91,215.08	$3,543.74	4.0%	$112,664.67	$116,677.46	$4,012.79	3.6%	$1,152,029.40	$1,196,430.48	$44,401.08	3.9%
720,000	$90,174.82	$93,819.49	$3,644.67	4.0%	$115,881.57	$120,008.45	$4,126.88	3.6%	$1,184,924.84	$1,230,589.72	$45,664.88	3.9%
740,000	$92,677.71	$96,423.08	$3,745.37	4.0%	$119,098.48	$123,339.43	$4,240.95	3.6%	$1,217,815.60	$1,264,742.36	$46,926.76	3.9%
760,000	$95,180.58	$99,026.68	$3,846.10	4.0%	$122,315.37	$126,670.42	$4,355.05	3.6%	$1,250,706.12	$1,298,895.12	$48,189.00	3.9%
780,000	$97,684.28	$101,631.08	$3,946.80	4.0%	$125,533.73	$130,003.10	$4,469.37	3.6%	$1,283,609.16	$1,333,061.04	$49,451.88	3.9%
800,000	$100,187.98	$104,235.49	$4,047.51	4.0%	$128,751.45	$133,334.90	$4,583.45	3.6%	$1,316,509.64	$1,367,223.52	$50,713.88	3.9%
	Average Winter Usage				**Average Summer Usage**							

{1} Annual Charges equals 8 months of winter charges and 4 months of summer charges.

Jersey Central Power & Light Company
General Service Transmission (GT) - Detailed Customer Impact Analysis
Full Service Charges
Dollar Figures Include 6.625 % Sales & Use Tax

Monthly Usage(kWh) (a)	Current Winter Total Full Service Charges (b)	Proposed Winter Total Full Service Charges (c)	Change in Total Winter Full Service Charges (d) = (c) - (b)	Percentage Change in Total Winter Full Service Charges (e) = (d) / (b)	Current Summer Total Full Service Charges (f)	Proposed Summer Total Full Service Charges (g)	Change in Total Summer Full Service Charges (h) = (g) - (f)	Percentage Change in Total Summer Full Service Charges (i) = (h) / (f)	Current Annual Total Full Service Charges {1} (j)	Proposed Annual Total Full Service Charges {1} (k)	Change in Total Annual Full Service Charges (l) = (k) - (j)	Percentage Change in Total Annual Full Service Charges (m) = (l) / (j)
200,000	$23,849.91	$24,659.85	$809.94	3.4%	$28,986.35	$29,865.43	$879.08	3.0%	$306,744.68	$316,740.52	$9,995.84	3.3%
250,000	$29,745.86	$30,738.43	$992.57	3.3%	$36,166.72	$37,245.83	$1,079.11	3.0%	$382,633.76	$394,890.76	$12,257.00	3.2%
300,000	$35,641.38	$36,816.71	$1,175.33	3.3%	$43,345.83	$44,624.80	$1,278.97	3.0%	$458,514.36	$473,032.88	$14,518.52	3.2%
350,000	$41,537.72	$42,895.80	$1,358.08	3.3%	$50,526.17	$52,005.15	$1,478.98	2.9%	$534,406.44	$551,187.00	$16,780.56	3.1%
400,000	$47,433.67	$48,974.39	$1,540.72	3.2%	$57,706.54	$59,385.56	$1,679.02	2.9%	$610,295.52	$629,337.36	$19,041.84	3.1%
450,000	$53,330.00	$55,053.49	$1,723.49	3.2%	$64,886.88	$66,765.91	$1,879.03	2.9%	$686,187.52	$707,491.56	$21,304.04	3.1%
500,000	$59,225.10	$61,131.20	$1,906.10	3.2%	$72,066.40	$74,145.44	$2,079.04	2.9%	$762,066.40	$785,631.36	$23,564.96	3.1%
550,000	$65,121.43	$67,210.30	$2,088.87	3.2%	$79,246.74	$81,525.79	$2,279.05	2.9%	$837,958.40	$863,785.56	$25,827.16	3.1%
600,000	$71,017.80	$73,289.44	$2,271.64	3.2%	$86,427.11	$88,906.19	$2,479.08	2.9%	$913,850.84	$941,940.28	$28,089.44	3.1%
650,000	$76,913.71	$79,367.97	$2,454.26	3.2%	$93,607.44	$96,286.54	$2,679.10	2.9%	$989,739.44	$1,020,089.92	$30,350.48	3.1%
700,000	$82,810.05	$85,447.07	$2,637.02	3.2%	$100,787.79	$103,666.90	$2,879.11	2.9%	$1,065,631.56	$1,098,244.16	$32,612.60	3.1%
750,000	$88,706.43	$91,526.23	$2,819.80	3.2%	$107,968.17	$111,047.30	$3,079.13	2.9%	$1,141,524.12	$1,176,399.04	$34,874.92	3.1%
800,000	$94,602.34	$97,604.75	$3,002.41	3.2%	$115,148.50	$118,427.65	$3,279.15	2.8%	$1,217,412.72	$1,254,548.60	$37,135.88	3.1%
850,000	$100,498.66	$103,683.85	$3,185.19	3.2%	$122,328.83	$125,808.00	$3,479.17	2.8%	$1,293,304.60	$1,332,702.80	$39,398.20	3.0%
900,000	$106,394.22	$109,762.18	$3,367.96	3.2%	$129,507.98	$133,187.02	$3,679.04	2.8%	$1,369,185.68	$1,410,845.52	$41,659.84	3.0%
950,000	$112,290.13	$115,840.71	$3,550.58	3.2%	$136,688.31	$140,567.37	$3,879.06	2.8%	$1,445,074.28	$1,488,995.16	$43,920.88	3.0%
1,000,000	$118,186.47	$121,919.80	$3,733.33	3.2%	$143,868.65	$147,947.72	$4,079.07	2.8%	$1,520,966.36	$1,567,149.28	$46,182.92	3.0%
913,681	$108,007.67	$111,425.51	**$3,417.84**	**3.2%**	$131,473.31	$135,207.18	$3,733.87	2.8%	$1,389,954.60	$1,432,232.80	$42,278.20	3.0%
1,050,000	$124,082.84	$127,998.96	$3,916.12	3.2%	$151,049.03	$155,328.12	$4,279.09	2.8%	$1,596,858.84	$1,645,304.16	$48,445.32	3.0%
1,100,000	$129,978.76	$134,077.49	$4,098.73	3.2%	$158,229.37	$162,708.48	$4,479.11	2.8%	$1,672,747.56	$1,723,453.84	$50,706.28	3.0%
935,861	$110,623.10	$114,122.02	$3,498.92	3.2%	**$134,658.47**	**$138,481.09**	**$3,822.62**	**2.8%**	$1,423,618.68	$1,466,900.52	$43,281.84	3.0%
1,150,000	$135,875.08	$140,156.59	$4,281.51	3.2%	$165,409.70	$170,088.83	$4,679.13	2.8%	$1,748,639.44	$1,801,608.04	$52,968.60	3.0%
1,200,000	$141,771.46	$146,235.73	$4,464.27	3.1%	$172,590.08	$177,469.23	$4,879.15	2.8%	$1,824,532.00	$1,879,762.76	$55,230.76	3.0%
1,250,000	$147,666.56	$152,313.45	$4,646.89	3.1%	$179,769.60	$184,848.77	$5,079.17	2.8%	$1,900,410.88	$1,957,902.68	$57,491.80	3.0%
1,300,000	$153,562.89	$158,392.54	$4,829.65	3.1%	$186,949.94	$192,229.11	$5,279.17	2.8%	$1,976,302.88	$2,036,056.76	$59,753.88	3.0%
1,350,000	$159,458.84	$164,471.13	$5,012.29	3.1%	$194,130.31	$199,609.52	$5,479.21	2.8%	$2,052,191.96	$2,114,207.12	$62,015.16	3.0%
1,400,000	$165,355.18	$170,550.22	$5,195.04	3.1%	$201,310.65	$206,989.87	$5,679.22	2.8%	$2,128,084.04	$2,192,361.24	$64,277.20	3.0%
1,450,000	$171,251.50	$176,629.32	$5,377.82	3.1%	$208,490.98	$214,370.22	$5,879.24	2.8%	$2,203,975.92	$2,270,515.44	$66,539.52	3.0%
1,500,000	$177,146.65	$182,707.08	$5,560.43	3.1%	$215,670.13	$221,749.24	$6,079.11	2.8%	$2,279,853.72	$2,348,653.60	$68,799.88	3.0%
1,550,000	$183,042.97	$188,786.18	$5,743.21	3.1%	$222,850.46	$229,129.59	$6,279.13	2.8%	$2,355,745.60	$2,426,807.80	$71,062.20	3.0%
1,600,000	$188,939.30	$194,865.27	$5,925.97	3.1%	$230,030.80	$236,509.94	$6,479.14	2.8%	$2,431,637.60	$2,504,961.92	$73,324.32	3.0%
1,650,000	$194,835.23	$200,943.81	$6,108.58	3.1%	$237,211.15	$243,890.29	$6,679.14	2.8%	$2,507,526.44	$2,583,111.64	$75,585.20	3.0%
1,700,000	$200,731.60	$207,022.96	$6,291.36	3.1%	$244,391.52	$251,270.70	$6,879.18	2.8%	$2,583,418.88	$2,661,266.48	$77,847.60	3.0%
1,750,000	$206,627.92	$213,102.06	$6,474.14	3.1%	$251,571.85	$258,651.05	$7,079.20	2.8%	$2,659,310.76	$2,739,420.68	$80,109.92	3.0%
1,800,000	$212,523.84	$219,180.58	$6,656.74	3.1%	$258,752.18	$266,031.40	$7,279.22	2.8%	$2,735,199.44	$2,817,570.24	$82,370.80	3.0%
1,850,000	$218,420.21	$225,259.73	$6,839.52	3.1%	$265,932.57	$273,411.80	$7,479.23	2.8%	$2,811,091.96	$2,895,725.04	$84,633.08	3.0%
1,900,000	$224,316.55	$231,338.83	$7,022.28	3.1%	$273,112.91	$280,792.15	$7,679.24	2.8%	$2,886,984.04	$2,973,879.24	$86,895.20	3.0%
1,950,000	$230,212.46	$237,417.36	$7,204.90	3.1%	$280,293.24	$288,172.50	$7,879.26	2.8%	$2,962,872.64	$3,052,028.88	$89,156.24	3.0%
2,000,000	$236,108.01	$243,495.69	$7,387.68	3.1%	$287,472.79	$295,552.09	$8,079.30	2.8%	$3,038,755.24	$3,130,173.88	$91,418.64	3.0%
2,050,000	$242,004.35	$249,574.80	$7,570.45	3.1%	$294,653.14	$302,932.45	$8,279.31	2.8%	$3,114,647.36	$3,208,328.20	$93,680.84	3.0%
2,100,000	$247,900.27	$255,653.32	$7,753.05	3.1%	$301,833.06	$310,312.23	$8,479.17	2.8%	$3,190,534.40	$3,286,475.48	$95,941.08	3.0%
2,150,000	$253,796.63	$261,732.47	$7,935.84	3.1%	$309,013.43	$317,692.63	$8,679.20	2.8%	$3,266,426.76	$3,364,630.28	$98,203.52	3.0%
2,200,000	$259,691.74	$267,810.18	$8,118.44	3.1%	$316,192.96	$325,072.16	$8,879.20	2.8%	$3,342,305.76	$3,442,770.08	$100,464.32	3.0%
2,250,000	$265,588.06	$273,889.28	$8,301.22	3.1%	$323,373.29	$332,452.51	$9,079.22	2.8%	$3,418,197.64	$3,520,924.28	$102,726.64	3.0%
2,300,000	$271,484.44	$279,968.43	$8,483.99	3.1%	$330,553.67	$339,832.92	$9,279.25	2.8%	$3,494,090.20	$3,599,079.12	$104,988.92	3.0%
2,350,000	$277,380.35	$286,046.96	$8,666.61	3.1%	$337,734.00	$347,213.27	$9,479.27	2.8%	$3,569,978.80	$3,677,228.76	$107,249.96	3.0%
2,400,000	$283,276.68	$292,126.05	$8,849.37	3.1%	$344,914.33	$354,593.62	$9,679.29	2.8%	$3,645,870.76	$3,755,382.88	$109,512.12	3.0%
2,450,000	$289,173.05	$298,205.21	$9,032.16	3.1%	$352,094.72	$361,974.02	$9,879.30	2.8%	$3,721,763.28	$3,833,537.76	$111,774.48	3.0%
		Average Winter Usage				**Average Summer Usage**						

{1} Annual Charges equals 8 months of winter charges and 4 months of summer charges.

COZEN O'CONNOR
A Pennsylvania Professional Corporation

April 10, 2023

Gregory Eisenstark
Direct Phone 973-200-7411
Direct Fax 973-200-7465
geisenstark@cozen.com

VIA E-MAIL (BOARD.SECRETARY@BPU.NJ.GOV)

Ms. Sherri Golden, Secretary
NJ Board of Public Utilities
44 South Clinton Street, 9th Floor
P.O. Box 350
Trenton, New Jersey 08625

Re: In the Matter of the Verified Petition of Jersey Central Power & Light Company for Review and Approval of Increases in and Other Adjustments to Its Rates and Charges For Electric Service, and For Approval of Other Proposed Tariff Revisions in Connection Therewith ("2023 Base Rate Filing")
BPU Docket No ER23030144

Dear Secretary Golden:

It has come to our attention that the version of the Direct Testimony of John J. Spanos (Exhibit JC-10) that was filed on March 16, 2023 contained incomplete versions of Appendix A and Exhibit JJS-2. Accordingly, we are filing a complete, corrected version of Exhibit JC-10. All parties should use this version in place of the earlier document.

This document is being filed with the Board Secretary electronically only, consistent with the Board's Order dated March 19, 2020 (Docket No. EO20030254) directing that all submissions to the Board, of any kind, be submitted electronically. We would appreciate if the Board Secretary's office would please acknowledge receipt of this filing.

Your anticipated courtesies and cooperation are deeply appreciated.

Respectfully submitted,

COZEN O'CONNOR

By: Gregory Eisenstark

Enclosures

cc: Service List via electronic mail (*via E-mail*)

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EXHIBIT JC-10

BEFORE THE
NEW JERSEY BOARD OF PUBLIC UTILITIES

In the Matter of the Verified Petition of Jersey Central Power & Light Company for Review and Approval of Increases in, and Other Adjustments to, Its Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith

Direct Testimony

of

John J. Spanos

Re: Depreciation Study and Proposed Depreciation Accrual Rates

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is John J. Spanos. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania, 17011.

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

A. I am employed by Gannett Fleming Valuation and Rate Consultants, LLC as President.

Q. Please describe your education and business experience.

A. I have Bachelor of Science degrees in Industrial Management and Mathematics from Carnegie-Mellon University and a Master of Business Administration from York College of Pennsylvania.

I have been associated with Gannett Fleming since 1986. Gannett Fleming Valuation and Rate Consultants, LLC provides depreciation consulting services to utility companies in the United States and Canada. As 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.

Q. Please state your qualifications.

A. I have over 36 years of depreciation experience, which includes giving expert testimony in more than 420 cases before 46 regulatory commissions, including the New Jersey Board of Public Utilities. These cases have included depreciation studies in the electric, gas, water, wastewater, and pipeline industries. In addition to cases where I have submitted testimony, I have supervised over 800 other depreciation or valuation assignments. Please refer to Appendix A for my qualifications statement, which includes further information with respect

to my work history, case experience and leadership in the Society of Depreciation Professionals.

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

A. I was asked to recommend depreciation rates for Jersey Central Power & Light Company's ("JCP&L" or the "Company") Electric Plant Accounts. I am sponsoring Exhibit JC-10, Schedule JJS-1 stating the results of my depreciation analysis related to JCP&L's electric plant as of June 30, 2022 (the "Depreciation Study" or "Study"). The recommended depreciation rates for JCP&L are set forth on pages VI-4 and VI-5.

Q. Would you please summarize your testimony?

A. My testimony will explain the methods and procedures of the Depreciation Study and sets forth the annual depreciation rates as of June 30, 2022 for intangible, distribution and general plant. Exhibit JC-10, Schedule JJS-1 sets forth detailed methods, procedures, and results of the Depreciation Study as of June 30, 2022. My Depreciation Study will be explained in Part II of my testimony.

Q. Please summarize the principal conclusion of your Depreciation Study.

A. The principal conclusion of the Study is that JCP&L's current depreciation rates need to be updated based on the more appropriate life parameters upon which the rates are based. I have proposed updated depreciation accrual rates by intangible, distribution, and general plant account in the Depreciation Study. Generally, my recommended rates are based on a combination of my review of historic data and JCP&L's operating maintenance practices, as well as the application of informed engineering judgment. Exhibit JC-10, Schedule JJS-2 sets forth a comparison of the proposed rates with the current rates as of June 30, 2022. As of June 30, 2022, the recommended depreciation rates increase depreciation expense by $11.0

million when compared to the depreciation expense that results from the currently approved depreciation rates. In this case, JCP&L is requesting to update the net salvage normalization component in its depreciation expense, based on its actual Cost of Removal experience over the most recent 5 years. Applying the net normalization method to calculate a net salvage component in depreciation expense for the most recent 5 years would be $27,302,335, which represents an increase to expense, as calculated through June 30, 2022, of $5,568,278 (compared to the $21,734,057 of net salvage I found in my 2019 depreciation study for the Company). *See* the Testimony of Carol A. Pittavino, Exhibit JC-3, Adjustments 13 and 14, which set forth her calculations of projected depreciation expense through the end of the test year, June 30, 2023.

The most significant contributor to the depreciation expense is an increase of $14.5 million related to FERC Account 365: Overhead Conductor and Devices. My review of JCP&L's experience indicates significant changes in plant investment in Account 365 since 2012, which would be expected, given the storm damage that JCP&L has experienced (*See* Testimony of Dennis Pavagadhi, Exhibit JC-5).

Q. Please explain how the practice for net salvage that has been used in New Jersey impacts the depreciation accruals that result from the Depreciation Study.

A. The current practice in New Jersey for the recovery of net salvage costs is different from the practice in most jurisdictions, in that net salvage is not recovered over the lives of the Company's assets while they are in service. Rather, a net salvage normalization has typically been established in which net salvage costs are recovered after the related assets are retired. This approach is referred to as the "net salvage normalization method," and contrasts with the traditional method of accruing for net salvage over the life of the Company's assets (which is referred to as the "traditional method" or "traditional accrual method"). One result of this

practice is that, if a company spends more money on cost of removal, there will be a resulting increase in depreciation expense in the next depreciation study to recover these historical net salvage costs. Additionally, the increase in the Depreciation Study is the result of higher removal costs that were incurred in the last five years.

Q. Please describe the contents of your report.

A. The Study is presented in eight parts:

Part I, Introduction, presents the scope and basis for the Depreciation Study;

Part II, Estimation of Survivor Curves, explains the process of estimating survivor curves and the retirement rate method of life analysis;

Part III, Service Life Considerations, discusses factors and the informed judgment involved with the estimation of service life;

Part IV, Net Salvage Considerations, discusses the process of determining the net salvage normalization component;

Part V, Calculation of Annual and Accrued Depreciation, explains the method, procedure and technique used in the calculation of annual depreciation expense and the theoretical reserve;

Part VI, Results of Study, sets forth the service life estimates, net salvage normalization expense, and annual depreciation rates and accruals for each depreciable group. This section also includes a description of the detailed tabulations supporting the Depreciation Study;

Part VII, Service Life Statistics, sets forth the survivor curve estimates and original life tables for each plant account and subaccount; and

Part VIII, Detailed Depreciation Calculations, sets forth the calculation of average remaining life for each property group.

The table on pages VI-4 and VI-5 of the report presents the results of the Study, including: (1) the estimated survivor curve; (2) the original cost as of June 30, 2022; (3) the

book reserve; and (4) the proposed annual depreciation accrual and rate for each account or subaccount. The section beginning on page VII-2 of the report presents the results of the retirement rate analyses, which set forth the historical bases for the service life estimates. The section beginning on page VIII-2 of Exhibit JC-10, Schedule JJS-1 presents the depreciation calculations related to surviving original cost as of June 30, 2022.

II. METHODS USED IN 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 operations and against which the Company is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and the requirements of public authorities.

Q. In preparing the depreciation study, did you follow generally accepted practices in the field of depreciation and valuation?

A. Yes.

Q. Please identify the depreciation method that you used.

A. I used the straight-line remaining life method of depreciation, with the average service life procedure. This is the method that JCP&L used in its most recent rate proceeding. This method of depreciation aims to distribute the unrecovered cost of fixed capital assets over the estimated remaining useful life of each unit or group of assets in a systematic and rational manner.

For General Plant Accounts 391.10, 391.15, 391.20. 391.25, 393, 394, 395, 397, and 398, I used the straight-line remaining life method of amortization. The account numbers identified throughout my testimony represent those in effect as of June 30, 2022. The annual amortization is based on amortization accounting that distributes the unrecovered cost of fixed capital assets over the remaining amortization period selected for each account and vintage. These amounts relate to the portion related to the distribution entity.

Q. What are your recommended annual depreciation accrual rates for JCP&L?

A. My recommended annual depreciation accrual rates as of June 30, 2022 for JCP&L are set forth on pages VI-4 and VI-5 of the Depreciation Study.

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

A. I did this in two phases. In the first phase, I estimated the service life characteristics for each depreciable group (*i.e.,* each plant account or subaccount identified as having similar characteristics). I also determined the most appropriate level of net salvage normalization by account. In the second phase, I calculated the composite remaining lives and annual depreciation accrual rates based on the service life estimates determined in the first phase.

Q. Please describe the first phase of the Depreciation Study, in which you estimated the service life characteristics for each depreciable group.

A. The service life study consisted of compiling historic data from records related to JCP&L's plant; analyzing these data to obtain historic trends of survivor characteristics; obtaining supplementary information from management and operating personnel concerning practices and plans as they relate to plant operations; and interpreting the above data and the estimates used by other electric utilities to form judgments of average service life characteristics**.**

Q. What historic data did you analyze for the purpose of estimating service life characteristics?

A. I analyzed the Company's accounting entries that record plant transactions primarily for the period, 1939 through 2021. The transactions included additions, retirements, transfers and the related balances. The Company records also included surviving dollar value by year installed for each plant account as of June 30, 2022.

Q. What method did you use to analyze this service life data?

A. I used the retirement rate method for all accounts. This is the most appropriate method when aged retirement data are available because it determines the average rates of retirement experienced by the Company during the period covered by the study.

Q. Would you explain how you used the retirement rate method to analyze JCP&L's service life data?

A. I applied the retirement rate method to each different group of property in the study. For each property group, I 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 several 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 to use them as valid considerations in estimating service life. The Iowa-type survivor curves were used to perform these interpretations.

Q. What is an "Iowa-type survivor curve" and how did you use such curves to estimate the service life characteristics for each property group?

A. Iowa-type curves are a widely used group of generalized 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 University College of 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 curves and truncated Iowa curves were used in this study to describe the forecasted rates of retirement based on the observed rates of retirement and the outlook for future retirements. As I will explain, the use of truncated curves is appropriate to reflect retirements of plant components that may not be fully depreciated at the time a plant is retired.

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. For example, the Iowa 47-R1.5 indicates an average service life of forty-seven years; a right-moded, or R, type curve (the mode occurs after average life for right-moded curves); and a low height, 1.5, for the mode (possible modes for R type curves range from 1 to 5) and the results incorporated in the estimation of the facility's life span.

Q. Should the estimation of survivor curves be based solely on the results of statistical life analyses?

A. No. Because depreciation requires the estimation of future service lives for assets currently in service, and because the historical database only allows for the analysis of a portion of the full-service lives of each group of assets, informed judgment is necessary to determine the

most reasonable survivor curve estimate. Judgment must be used not only to incorporate information external to the statistical analyses, but also to properly interpret the historical data as part of the curve fitting process. Authoritative depreciation texts support that judgment is necessary in the estimation of depreciation, and that reliance only on statistical results can, and does, produce unreasonable results.

Q. Have you physically observed JCP&L's assets as part of your depreciation studies?

A. Yes. I made a field review of JCP&L's property in November 2022 to update my analyses on a representative portion of plant. Prior field visits were conducted in May 2013 and September 2019. Field reviews are conducted to become familiar with Company operations and obtain an understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements. For example, I had detailed discussions with Company personnel regarding the different forces of retirement for some of their regions. This knowledge as well as information from other discussions with management was incorporated into my statistical analyses.

Q. How did your experience in development of other depreciation studies affect your work in this case?

A. Because I customarily conduct field reviews for my depreciation studies, I have had the opportunity to visit scores of similar facilities and meet with operations personnel at other companies. The knowledge accumulated from those visits and meetings provide me useful information that I can draw on to confirm or challenge my numerical analyses concerning asset condition and remaining life estimates.

Q. Would you please explain the concept of "net salvage"?

A. Net salvage is a component of the service value of capital assets that is recovered through depreciation rates. The service value of an asset is its original cost less its net salvage. Net salvage is the salvage value received for the asset upon retirement less the cost to retire the asset. When the cost to retire exceeds the salvage value, the result is negative net salvage.

In as much as depreciation expense is the loss in service value of an asset during a defined period, *e.g.*, one year, it must include a ratable portion of both the original cost and the net salvage. That is, the net salvage related to an asset should be incorporated in the cost of service during the same period as its original cost so that customers receiving service from the asset pay rates that include a portion of both elements of the asset's service value, the original cost and the net salvage value. For example, the full recovery of the service value of a $5,000 distribution pole will include not only the $5,000 of original cost, but also, on average, $500 to remove the pole at the end of its life and $50 in salvage value. In this example, the net salvage component is negative $450 ($50 - $500).

Q. Have you included a net salvage component as part of the depreciation accrual rates in the Study?

A. Yes. The recommended depreciation rates provided in Table 1 of the Depreciation Study incorporate the net salvage normalization method. The net salvage normalization method is only designed to recover net salvage costs, based on a historical 5-year average experience, and does not recover net salvage costs over the period of time the related assets will be in service.

Based on the currently accepted practice of the New Jersey Board of Public Utilities, the Company's proposal in this case uses the depreciation rates shown on Table 1 of the Study that incorporate the net salvage normalization method. For ratemaking purposes, while the

net salvage normalization method is an improvement over expensing net salvage costs (*i.e.*, Cost of Removal), I do not believe the net salvage normalization method is the most reasonable method for recovery of net salvage costs. Most appropriately, depreciation expense would include a ratable portion of both the original cost and the net salvage over the life of the assets providing service.

Q. Please describe how you calculated the net salvage normalization amounts used in the depreciation rates provided in Table 1 of the Study.

A. For purposes of the depreciation rates based on the net salvage normalization method, the net salvage normalization amounts for each account were calculated based on historical data for the period 2017 through 2021. In the historical analyses, cost of removal and gross salvage amounts were recorded by account within the 5-year period, 2017 – 2021, and set forth on Table 2, page VI-6 of the depreciation study. Years prior to 2017 were reviewed to understand the trends of cost of removal and gross salvage. The most distinct trend from prior years is that cost of removal has increased significantly. Reasons for the increase in recorded costs of removal include the increased volume of work associated with reliability improvements, as well as the costs of work to replace assets that were damaged as a result of storms.

Once these data were assembled, I calculated the five-year average of the 2017 - 2021 experienced costs and incorporated that average as the annual net salvage expense reflected in the depreciation rates based on the net salvage normalization method.

Q. Please describe the process that you used in the Depreciation Study to calculate composite remaining lives and annual depreciation accrual rates.

A. After I estimated the service life characteristics for each depreciable property group, I calculated the annual depreciation accrual rates for each group based on the straight-line remaining life method, using remaining lives weighted consistent with the average service life procedure. The annual depreciation accrual rates were developed as of June 30, 2022.

Q. Please describe the straight-line remaining life method of depreciation.

A. The straight-line remaining life method of depreciation allocates the original cost of the property, less accumulated depreciation, less future net salvage, in equal amounts to each year of remaining service life.

Q. Please describe the average service life procedure for calculating remaining life accrual rates.

A. The average service life procedure defines the group for which the remaining life annual accrual is determined. Under this procedure, the annual accrual rate is determined for the entire group or account based on its average remaining life and this rate is applied to the surviving balance of the group's cost. The average remaining life of the group is calculated by first dividing the future book accruals (original cost less allocated book reserve less future net salvage) by the average remaining life for each vintage. The average remaining life for each vintage is derived from the area under the survivor curve between the attained age of the vintage and the maximum age. Then, the sum of the future book accruals is divided by the sum of the annual accruals to determine the average remaining life of the entire group for use in calculating the annual depreciation accrual rate.

Q. You stated earlier that for certain general plant accounts you used amortization accounting to calculate proposed deprecation rates. Could you please describe amortization accounting?

A. Yes. In amortization accounting, units of property are capitalized in the same manner as they are in depreciation accounting. However, amortization accounting is more appropriate than depreciation accounting for accounts with a large number of units, but small asset values. This is true because in order to properly reflect plant in service, depreciation accounting requires periodic inventories, which is a difficult and burdensome task for these assets (*i.e.*, large number of units, but small values). Consequently, a more accurate method is to record retirements when a vintage is fully amortized rather than when the units are removed from service. As a result, there is no dispersion of retirement. All units are retired when the age of the vintage reaches the amortization period. Each plant account or group of assets is assigned a fixed period which represents an anticipated life which the asset will render full benefit. For example, in amortization accounting, assets that have a 20-year amortization period will be fully recovered after 20 years of service and taken off the Company's books, but not necessarily removed from service. In contrast, assets that are taken out of service before 20 years remain on the books until the amortization period for that vintage has expired.

Q. Can you explain why you recommend amortization accounting?

A. Amortization accounting has been implemented by almost all utility companies across the United States and Canada over the past 25-30 years. I have continued to present this methodology in the depreciation study to smooth the annual depreciation accrual rate over time for the specific asset classes described in general plant as well as to improve record keeping practices for a large number of assets that have a small utility plant in service value.

Q. Is amortization accounting currently used for certain General Plant accounts for JCP&L?

A. Yes. Amortization accounting has been implemented in JCP&L's previous depreciation studies.

Q. For which plant accounts is amortization accounting being utilized?

A. Amortization accounting is only appropriate for certain General Plant accounts. These are accounts 391.10, 391.15, 391.20. 391.25, 393, 394, 395, 397, and 398 for electric plant. They represent slightly more than two percent of depreciable plant in this study.

Q. Are there any specific adjustments made to accounts for which amortization accounting is used?

A. Yes. The preference for amortization accounting is that the rate applied to each plant account is equal to one divided by the amortization period. Because assets are retired once they reach the end of the amortization period, this rate can be consistently applied going forward.

However, when amortization accounting is properly implemented, there is typically a difference between the book reserve and the accumulated depreciation amount that would result in a calculated remaining life rate that is equal to one divided by the amortization period. Additionally, assets older than the amortization period need to be retired when amortization accounting is implemented. For these reasons, an adjustment may be made to amortize any accumulated depreciation differences over a shorter period of time. I have recommended to make such an adjustment in the Depreciation Study. Because depreciation studies are conducted periodically, the intent is that using a four-year period, which is a typical time between depreciation studies, will mean that similar adjustments will not be needed in future depreciation studies. Therefore, some of the reserve amortization relates to the current amortization that was initiated in January 2021.

Q. Please use an example to illustrate the development of the annual depreciation accrual rate for a particular group of property in your depreciation study.

A. I will use Account 365, Overhead Conductors and Devices, as an example because it is one of the largest depreciable groups and represents 18% of depreciable plant for JCP&L.

I used the retirement rate method to analyze the survivor characteristics of this property group. I compiled aged plant accounting data from 1934 through 2021 and analyzed the data for periods that best represent the overall service life of the property. I present the life tables for the 1934-2021 and 1957-2021 experience bands on pages VII-33 through VII-38 of Exhibit JC-10, Schedule JJS-1. The life table displays the retirement and surviving ratios of the aged plant data exposed to retirement by age interval. For example, page VII-33 shows $15,414,318 retired during age interval 0.5-1.5 with $1,298,444,701 exposed to retirement at the beginning of the interval. Consequently, the retirement ratio is 0.0119 ($15,414,318/$1,298,444,701) and the surviving ratio is 0.9881 (1-0.0119). The percent surviving at age 0.5 of 0.9948 percent is multiplied by the survivor ratio of 98.81 to derive the percent surviving at age 1.5 of 98.30 percent. This process continues for the remaining age intervals for which plant was exposed to retirement during the period 1934-2021. The resultant life tables, or original survivor curves, are plotted along with the estimated smooth survivor curve, the 36-R0.5 on page VII-32.

I present the net salvage normalization amount on page VI-6. This amount of negative $27,302,335, which is the five-year average of net salvage costs for the period, 2017-2021, is brought forward to column 9 of Table 1 on pages VI-4 and VI-5 of the Depreciation Study.

I provide my calculation of the annual depreciation related to original cost of Account 365, Overhead Conductors and Devices, as of June 30, 2022, on pages VIII-15 and VIII-16 Exhibit JC-10, Schedule JJS-1. The calculation is based on the 36-R0.5 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 for the annual depreciation amount by account.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Jersey Central® Power & Light

A FirstEnergy Company

2022 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS
RELATED TO ELECTRIC PLANT
AS OF JUNE 30, 2022

Prepared by:

GANNETT FLEMING

Excellence Delivered As Promised

JERSEY CENTRAL POWER & LIGHT COMPANY

Morristown, New Jersey

2022 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS
RELATED TO ELECTRIC PLANT
AS OF JUNE 30, 2022

GANNETT FLEMING VALUATION AND RATE CONSULTANTS, LLC

Camp Hill, Pennsylvania

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March 13, 2023

Jersey Central Power & Light Company
300 Madison Avenue
Morristown, NJ 07960

Attention: Mr. Mark A. Mader
Director, Rates and Regulatory Affairs

Ladies and Gentlemen:

Pursuant to your request, we have conducted a depreciation study related to the electric intangible, distribution and general plant of Jersey Central Power & Light Company as of June 30, 2022. 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

JOHN J. SPANOS
President

JJS:jmr
072153.000

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JERSEY CENTRAL POWER & LIGHT COMPANY

DEPRECIATION STUDY

EXECUTIVE SUMMARY

Pursuant to Jersey Central Power & Light Company's ("JCP&L" or "Company") request, Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming") conducted a depreciation study related to the electric intangible, distribution and general plant as of June 30, 2022. The purpose of this study was to determine the annual depreciation accrual rates and amounts for book and ratemaking purposes.

The depreciation rates are based on the straight line method using the average service life ("ASL") procedure and were applied on a remaining life basis. The calculations were based on attained ages and estimated average service life, survivor curve and net salvage normalization component for each depreciable group of assets.

JCP&L's accounting policy has not changed since the last depreciation study related to the distribution plant. However, there have been some changes in life parameters and net salvage recovery methods which have caused the proposed remaining lives for some accounts to change from those previously approved.

Gannett Fleming recommends the calculated annual depreciation accrual rates set forth herein apply specifically to electric distribution plant and the allocated portion of intangible and general plant in service as of June 30, 2022 as summarized by Table 1 of the study. Supporting analysis and calculations are provided within the study.

The study results set forth an annual depreciation expense of $162.7 million when applied to the related depreciable electric distribution plant balances as of June 30, 2022.

SUMMARY OF ORIGINAL COST, PROPOSED ACCRUAL RATES AND AMOUNTS

FUNCTION	ORIGINAL COST AS OF JUNE 30, 2022	ACCRUAL RATE	ACCRUAL AMOUNT
Intangible Plant	$ 133,568,110.77	-	$ 8,612,677
Distribution Plant	5,365,179,527.62	2.63	141,084,529
General Plant	235,732,543.05	4.45	10,492,719
General Plant Reserve Amortization	-	-	2,473,556
Total Depreciable Plant	**$5,734,480,181.44**	**2.84**	**$162,663,481**

PART I. INTRODUCTION

JERSEY CENTRAL POWER & LIGHT COMPANY

DEPRECIATION STUDY

PART I. INTRODUCTION

SCOPE

This report sets forth the results of the depreciation study for Jersey Central Power & Light Company ("Company"), as applied to electric intangible, distribution and general plant in service as of June 30, 2022. 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 distribution and general plant in service as of June 30, 2022.

The service life estimates resulting from the study were based on informed judgment which incorporated analyses of historical plant retirement data as recorded through 2021, the net salvage normalization of historical plant retirement data recorded for the most recent five years, 2017-2021; 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 and net salvage estimates 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 study. 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 normalization component. Part V, Calculation of Annual and Accrued Depreciation, describes the procedures used in the calculation of group depreciation. Part VI, Results of Study, presents a summary 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 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 electric 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. For

certain General Plant Accounts, the annual depreciation was based on amortization accounting. The calculated remaining lives and annual depreciation accrual rates were based on attained ages of plant in service and the estimated service life and salvage characteristics of each depreciable group.

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 the Federal Energy Regulatory Commission (FERC). Gannett Fleming recommends its continued use.

Service Life Estimates and Net Salvage Component

The service life estimates used in the depreciation 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 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 property. Iowa type survivor curves were used to depict the estimated survivor curves for the plant accounts.

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 and forecasted 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.

The net salvage normalization component by account incorporated a review of experienced costs of removal and gross salvage for the most recent five years related to plant retirements.

An understanding of the function of the plant and information with respect to the reasons for past retirements and the expected causes of future retirements was obtained through discussions with operating and management personnel. The supplemental information obtained in this manner was considered in the interpretation and extrapolation of the statistical analyses.

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.

This study has incorporated the use of Iowa curves developed from a retirement rate analysis of historical retirement history. A discussion of the concepts of survivor curves and 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 (or the portion of the frequency curve with the highest level of 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. A higher number designates a higher mode curve.

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.

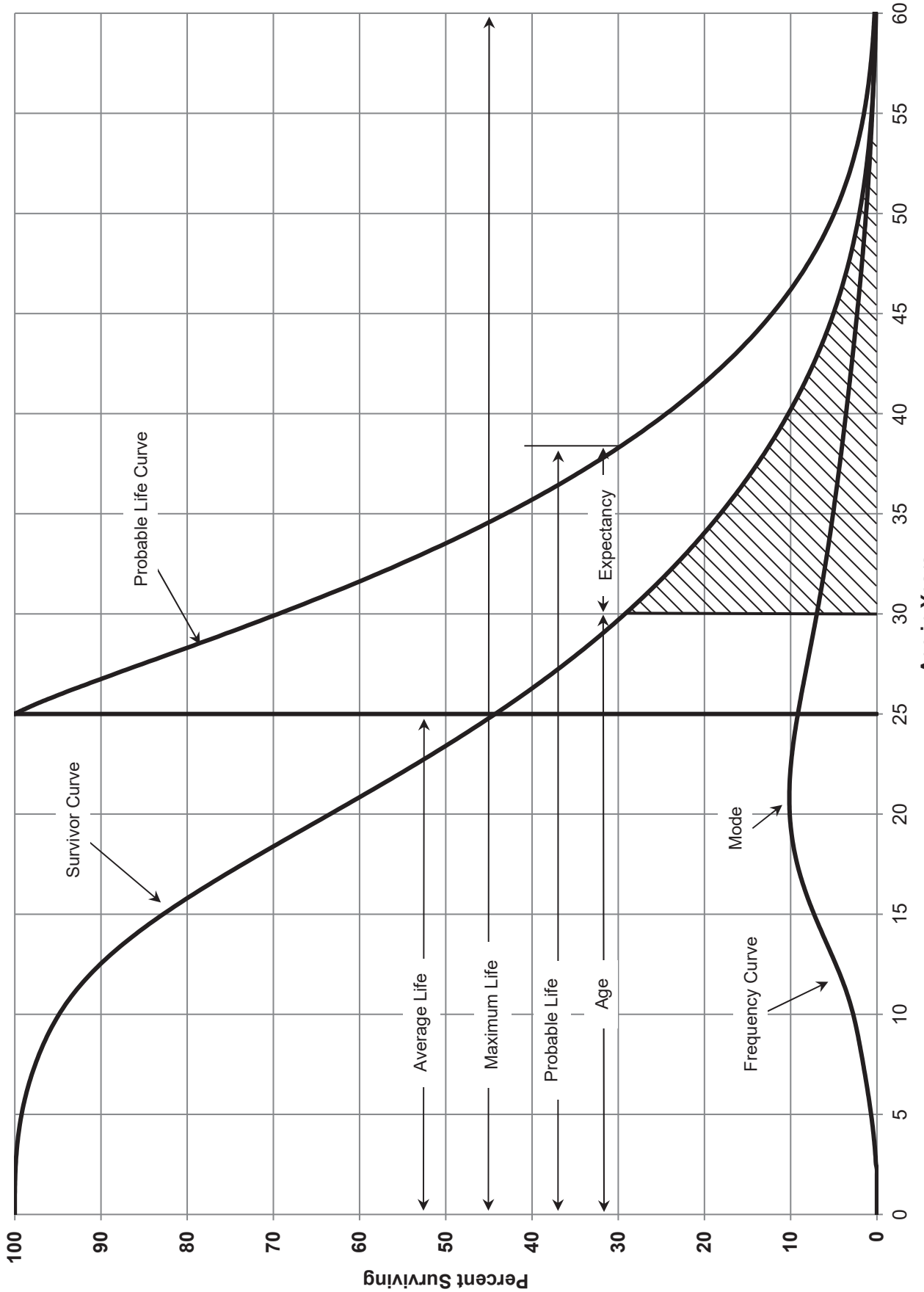

FIGURE 1. TYPICAL SURVIVOR CURVE AND DERIVED CURVES

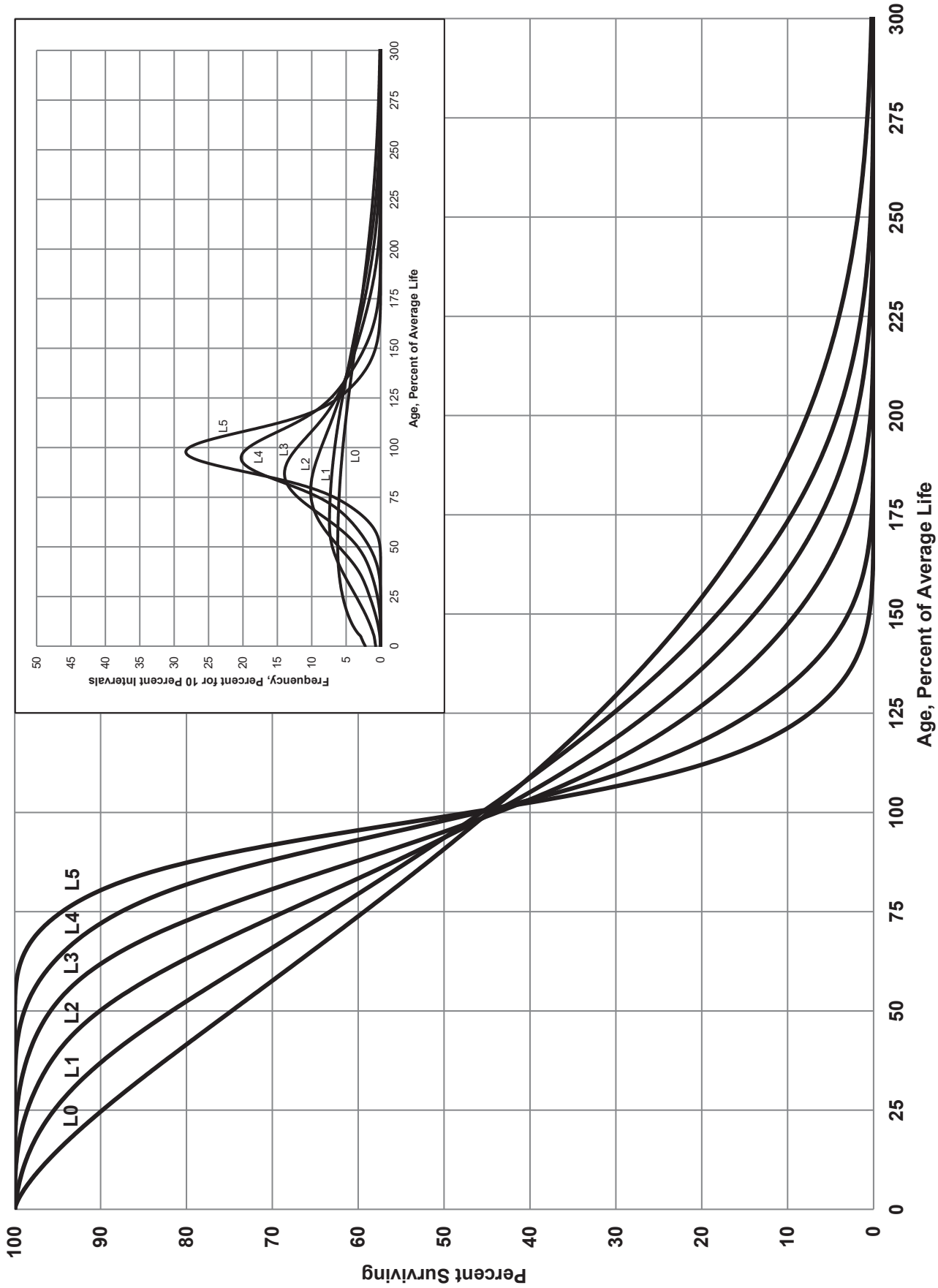

FIGURE 2.. LEFT MODAL OR "L" IOWA TYPE SURVIVOR CURVES

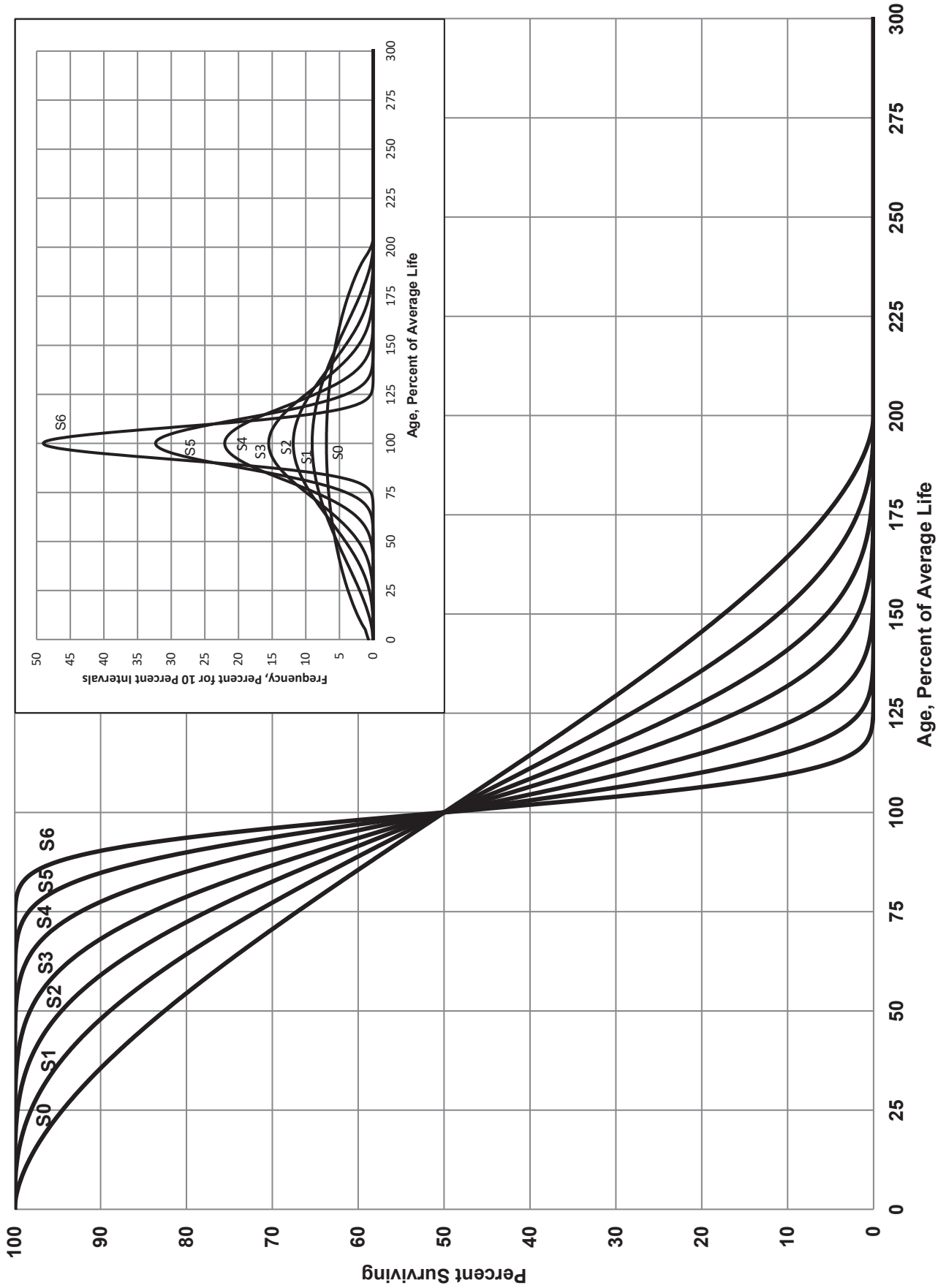

FIGURE 3.. SYMMETRICAL OR "S" IOWA TYPE SURVIVOR CURVES

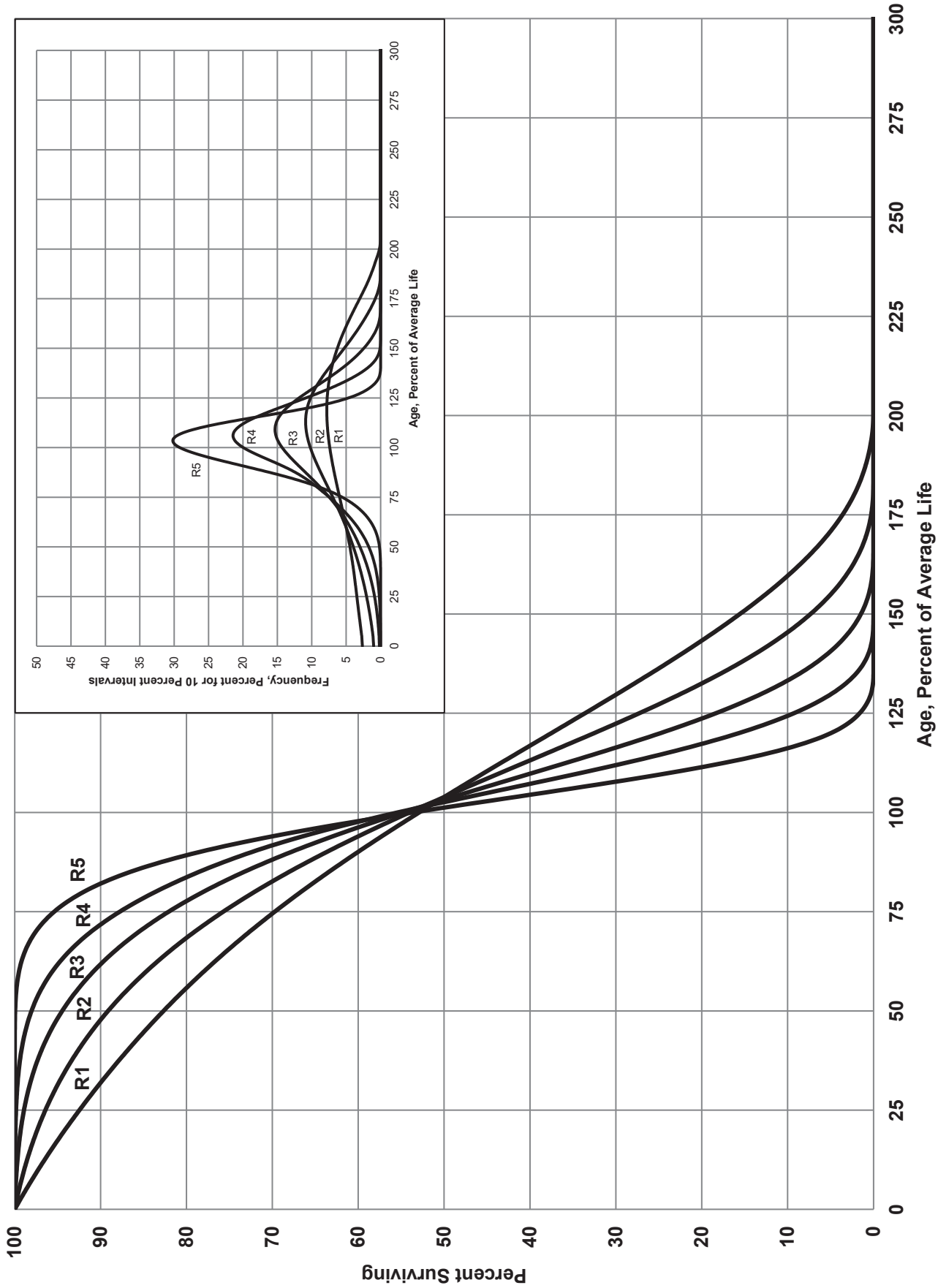

FIGURE 4.. RIGHT MODAL OR "R" IOWA TYPE SURVIVOR CURVES

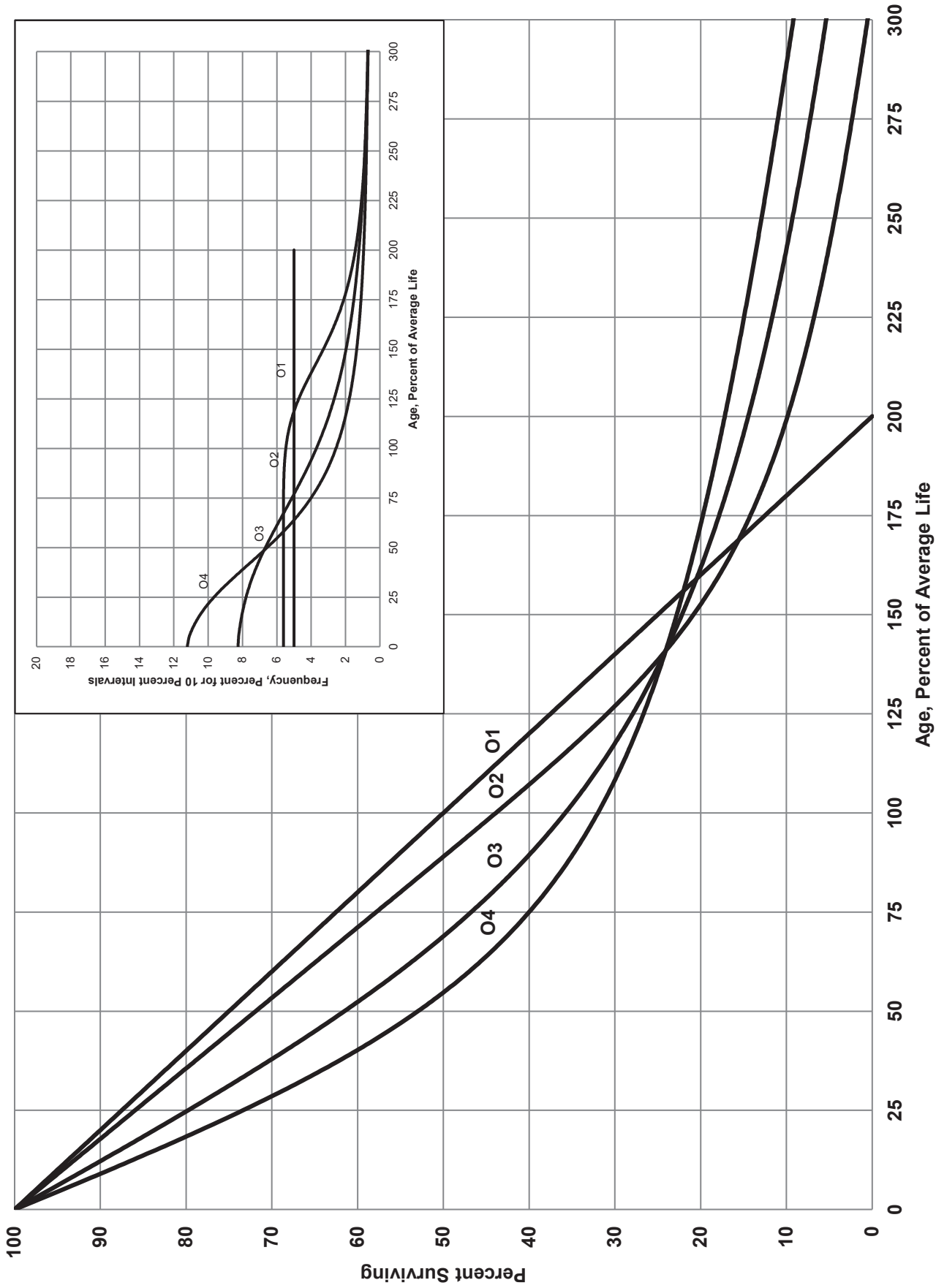

FIGURE 5. ORIGIN MODAL OR "O" IOWA TYPE SURVIVOR CURVES

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. 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 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.

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[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.

Schedules of Annual Transactions in Plant Records

The property group used to illustrate the retirement rate method is observed for the experience band 2012-2021 for which there were placements during the years 2007-2021. 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 2007 were retired in 2012. 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 2012 retirements of 2007 installations and ending with the 2021 retirements of the 2016 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 2012-2021
SUMMARIZED BY AGE INTERVAL

Experience Band 2012-2021 Placement Band 2007-2021

Year Placed	Retirements, Thousands of Dollars During Year										Total During Age Interval	Age Interval
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2007	10	11	12	13	14	16	23	24	25	26	26	13½-14½
2008	11	12	13	15	16	18	20	21	22	19	44	12½-13½
2009	11	12	13	14	16	17	19	21	22	18	64	11½-12½
2010	8	9	10	11	11	13	14	15	16	17	83	10½-11½
2011	9	10	11	12	13	14	16	17	19	20	93	9½-10½
2012	4	9	10	11	12	13	14	15	16	20	105	8½-9½
2013		5	11	12	13	14	15	16	18	20	113	7½-8½
2014			6	12	13	15	16	17	19	19	124	6½-7½
2015				6	13	15	16	17	19	19	131	5½-6½
2016					7	14	16	17	19	20	143	4½-5½
2017						8	18	20	22	23	146	3½-4½
2018							9	20	22	25	150	2½-3½
2019								11	23	25	151	1½-2½
2020									11	24	153	½-1½
2021										13	80	0-½
Total	53	68	86	106	128	157	196	231	273	308	1,606	

SCHEDULE 2. OTHER TRANSACTIONS FOR EACH YEAR 2012-2021
SUMMARIZED BY AGE INTERVAL

Experience Band 2012-2021 Placement Band 2007-2021

Year Placed	Acquisitions, Transfers and Sales, Thousands of Dollars During Year										Total During Age Interval	Age Interval
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2007	-	-	-	-	-	-	60[a]	-	-	-	-	13½-14½
2008	-	-	-	-	-	-	-	-	-	-	-	12½-13½
2009	-	-	-	-	-	-	-	-	-	-	-	11½-12½
2010	-	-	-	-	-	-	-	(5)[b]	-	-	60	10½-11½
2011	-	-	-	-	-	-	-	6[a]	-	-	-	9½-10½
2012	-	-	-	-	-	-	-	-	-	-	(5)	8½-9½
2013		-	-	-	-	-	-	-	-	-	6	7½-8½
2014			-	-	-	-	-	-	-	-	-	6½-7½
2015				-	-	-	-	(12)[b]	-	-	-	5½-6½
2016					-	-	-	-	22[a]	-	-	4½-5½
2017						-	-	(19)[b]	-	-	10	3½-4½
2018							-	-	-	-	-	2½-3½
2019								-	-	(102)[c]	(121)	1½-2½
2020									-	-	-	½-1½
2021											-	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 2012 through 2021 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 2017 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 2012-2021
SUMMARIZED BY AGE INTERVAL

Experience Band 2012-2021

Placement Band 2007-2021

Year Placed	Exposures, Thousands of Dollars — Annual Survivors at the Beginning of the Year										Total at Beginning of Age Interval	Age Interval
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021		
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
2007	255	245	234	222	209	195	239	216	192	167	167	13½-14½
2008	279	268	256	243	228	212	194	174	153	131	323	12½-13½
2009	307	296	284	271	257	241	224	205	184	162	531	11½-12½
2010	338	330	321	311	300	289	276	262	242	226	823	10½-11½
2011	376	367	357	346	334	321	307	297	280	261	1,097	9½-10½
2012	420[a]	416	407	397	386	374	361	347	332	316	1,503	8½-9½
2013		460[a]	455	444	432	419	405	390	374	356	1,952	7½-8½
2014			510[a]	504	492	479	464	448	431	412	2,463	6½-7½
2015				580[a]	574	561	546	530	501	482	3,057	5½-6½
2016					660[a]	653	639	623	628	609	3,789	4½-5½
2017						750[a]	742	724	685	663	4,332	3½-4½
2018							850[a]	841	821	799	4,955	2½-3½
2019								960[a]	949	926	5,719	1½-2½
2020									1,080[a]	1,069	6,579	½-1½
2021										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 2012-2021, 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 (Schedule 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 2012-2021 Placement Band 2007-2021

(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 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 Schedule 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 the best fit 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

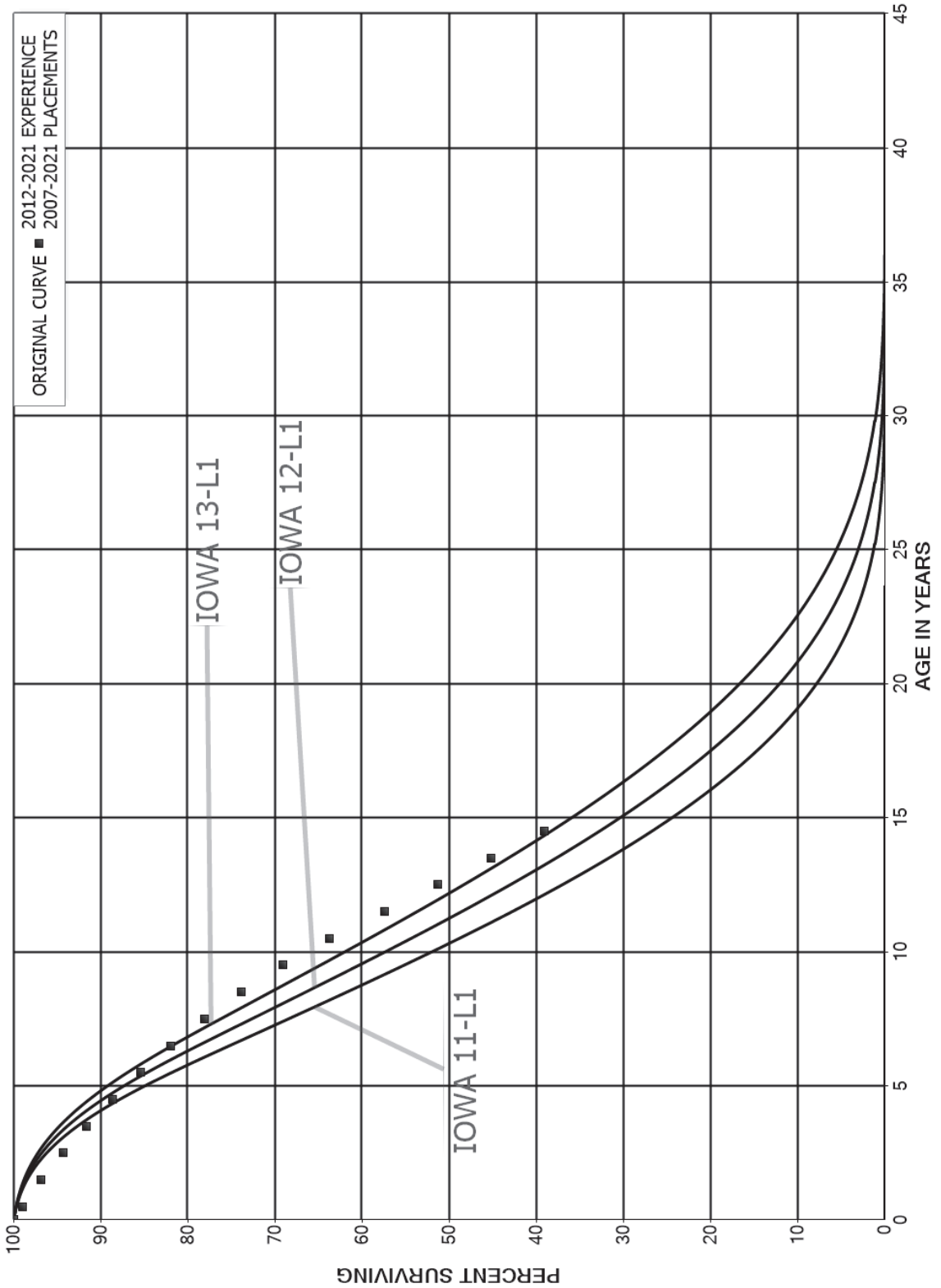


FIGURE 7. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN S0 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

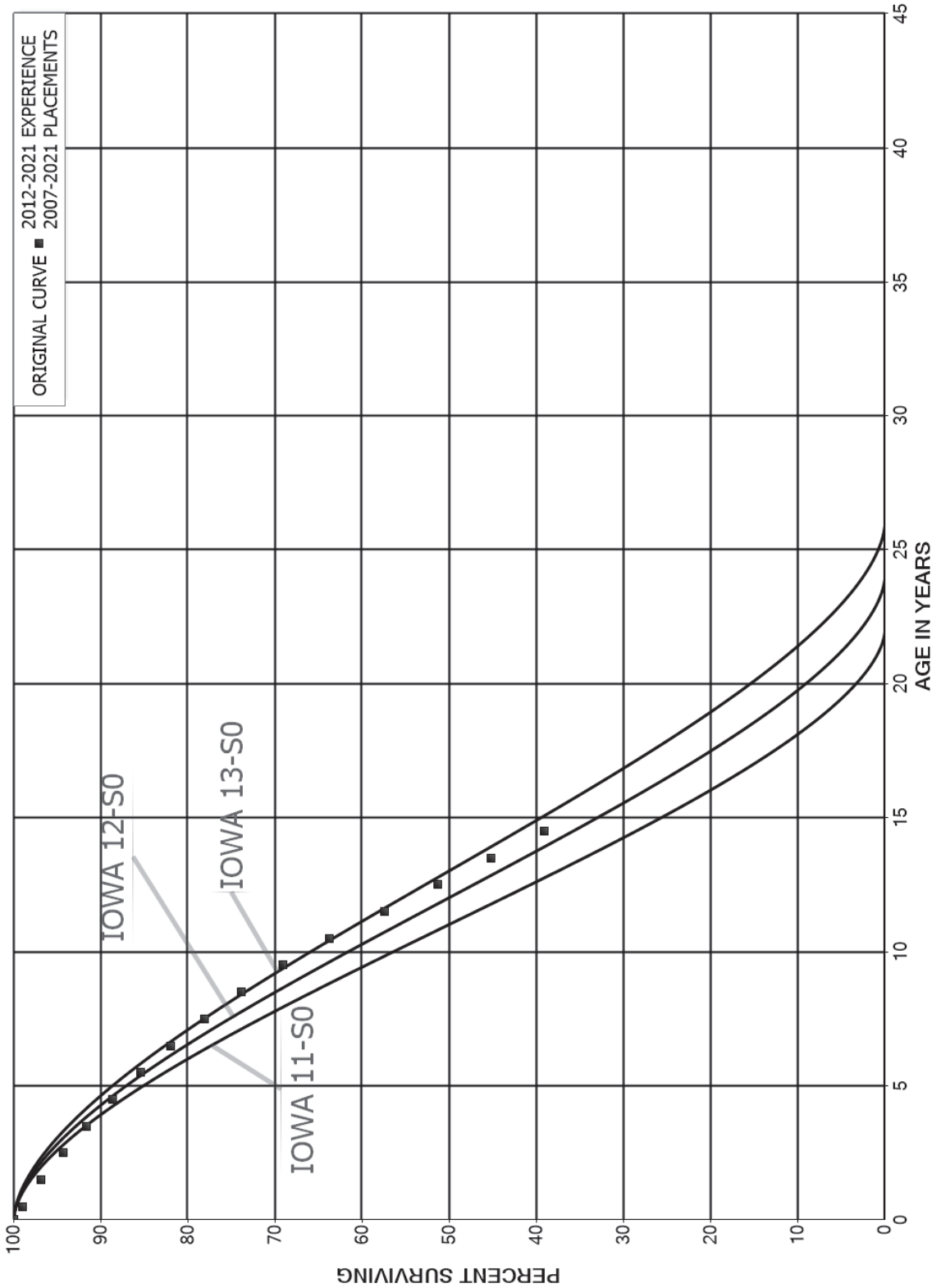


FIGURE 8. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES

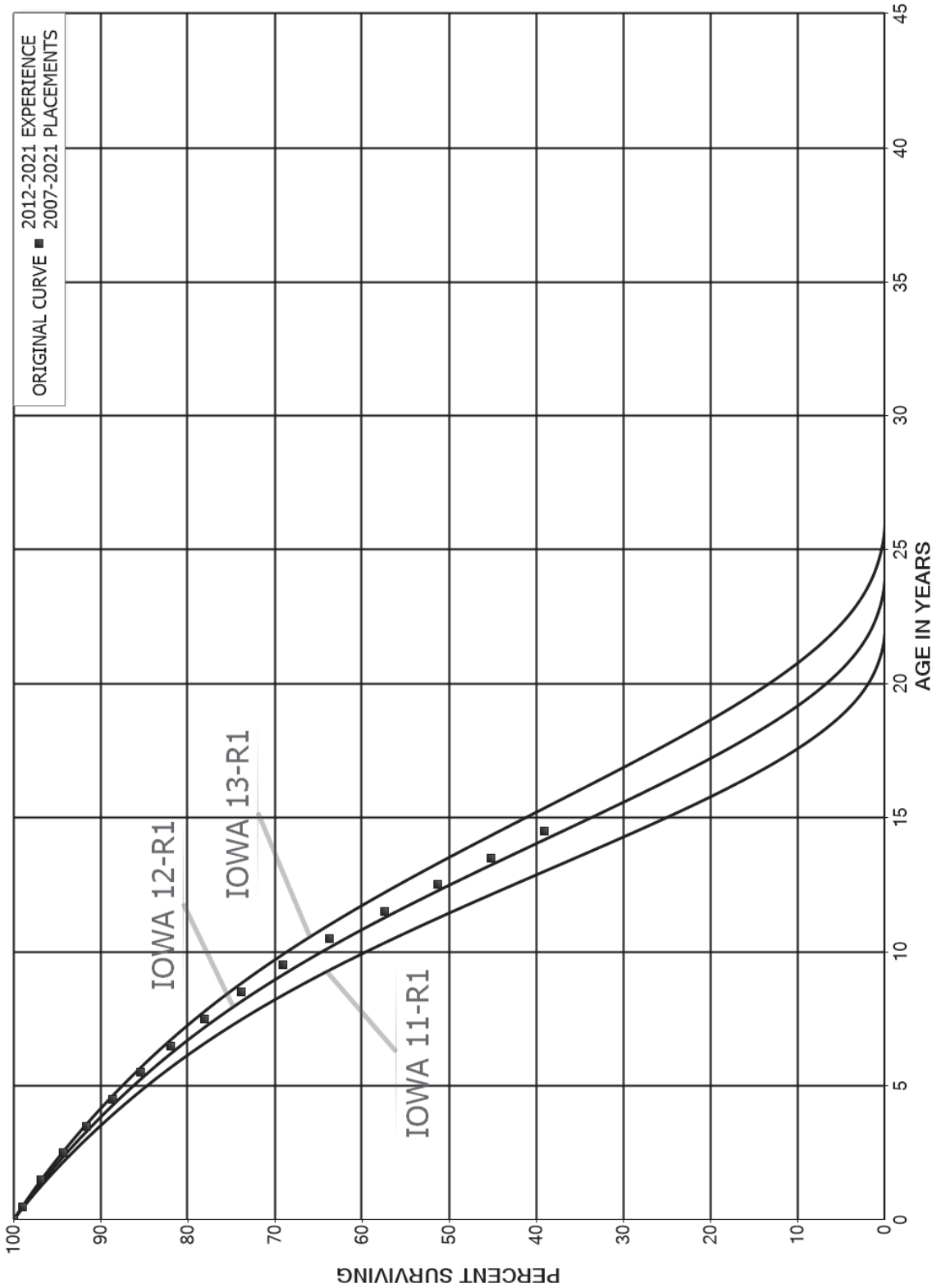
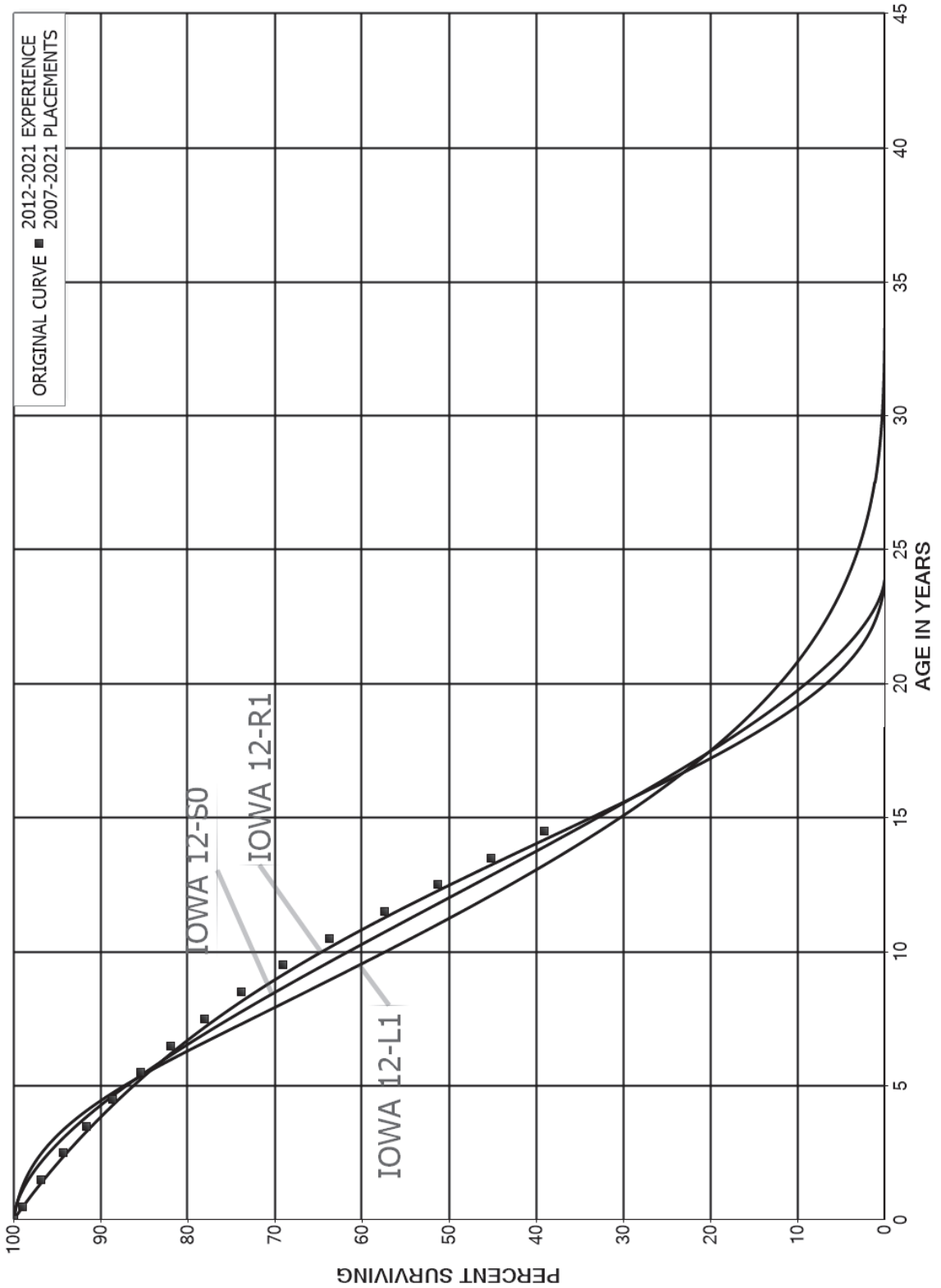


FIGURE 9. ILLUSTRATION OF THE MATCHING OF AN ORIGINAL SURVIVOR CURVE WITH AN L1, S0 AND R1 IOWA TYPE CURVE
ORIGINAL AND SMOOTH SURVIVOR CURVES



PART III. SERVICE LIFE CONSIDERATIONS

PART III. SERVICE LIFE CONSIDERATIONS

FIELD TRIPS

In order to be familiar with the operation of the Company and to observe representative portions of the plant, a field trip was conducted. A sampling of various types of facilities was selected to best represent the various assets in service. Aside from the obtained knowledge of age, type and condition of each group of assets that were visited, a discussion with key operational personnel as to the outlook of each asset group was conducted. A general understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements was obtained during each trip. This knowledge and information were incorporated in the interpretation and extrapolation of the statistical analyses.

The plant facilities visited during the most recent trips are as follows:

November 8, 2022
- Convent Substation
- Morristown General Office
- Traynor Substation
- Summit Service Center
- Mt. Fern Substation

September 26, 2019
- Morristown Legion Place Service Center
- Alderney Substation
- East Dover Substation
- Mount Fern Substation
- Morristown Substation

May 2, 2013
- Traynor Substation
- Summit Line Shop
- East Hanover Shop
- Whippany Substation
- Okner Parkway Substation
- Florham Park Substation
- Morris Plains Substation

SERVICE LIFE ANALYSIS

The service life estimates were based on 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 utility companies.

For 13 of the plant accounts and subaccounts for which survivor curves were estimated, the statistical analyses using the retirement rate method resulted in good to excellent indications of the survivor patterns experienced. These accounts represent 79 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.

DISTRIBUTION PLANT

362.00	Station Equipment
364.00	Poles, Towers and Fixtures
365.00	Overhead Conductors and Devices
367.00	Underground Conductors and Devices
368.00	Line Transformers
370.00	Meters
371.00	Installations on Customers' Premises
373.00	Street Lighting and Signal Systems
373.30	Street Lighting and Signal Systems - LED

GENERAL PLANT

390.10	Structures and Improvements
390.20	Structures and Improvements - Clearing
392.00	Transportation Equipment
396.00	Power Operated Equipment

Account 368.00, Line Transformers, is used to illustrate the manner in which the study was conducted for the groups in the preceding list. Aged plant accounting data for all plant accounts have been compiled for the years 1917 through 2021. These data have been coded in the course of the Company's normal record keeping according to

account or property group, type of transaction, year in which the transaction took place, and year in which the electric plant was placed in service. The retirements, other plant transactions, and plant additions were analyzed by the retirement rate method.

The survivor curve estimate is based on the statistical indications for the periods, 1917-2021 and 1972-2021. The Iowa 42-R1 is an excellent fit of the original survivor curve. The 42-year service life is within the typical service life range of 35 to 45 years for line transformers. The 42-year life reflects the Company's plans to systematically replace line transformers as they fail or need upgrades due to demand or load.

For Account 364.00, Poles, Towers and Fixtures, the aged accounting data for the period, 1939-2021, was analyzed. The statistical indications for the period, 1939-2021 and 1992-2021, were the primary basis for the selection of the 50-R1.5 survivor curve. The 50-year service life is within the typical range of 40-55 years for distribution poles.

The survivor curve estimates for the remaining accounts were based on judgment incorporating the statistical analyses and previous studies for this and other electric utilities.

PART IV. NET SALVAGE CONSIDERATIONS

PART IV. NET SALVAGE CONSIDERATIONS

NET SALVAGE NORMALIZATION

The net salvage component by account was based on historical data compiled for the five-year period, 2017-2021. Cost of removal and gross salvage were recorded each year by account. The totals by account were calculated to determine the annual net salvage amount that will be included in the total annual accrual rate. The amounts are set forth on Table 2 and brought forward to Table 1.

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:

$$\$1{,}000\left(1 - \frac{6}{10}\right) = \$400.$$

Remaining Life Annual Accruals

For the purpose of calculating remaining life accruals as of June 30, 2022, the depreciation reserve for each plant account is allocated among vintages in proportion to the calculated accrued depreciation for the account. Explanations of remaining life accruals and calculated accrued depreciation follow. The detailed calculations as of June 30, 2022, are set forth in the Results of Study section of the report.

Average Service Life Procedure

In the average service life procedure, the remaining life annual accrual for each vintage is determined by dividing future book accruals (original cost less book reserve) by the average remaining life of the vintage. The average remaining life is a directly weighted average derived from the estimated future survivor curve in accordance with the average service life procedure.

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, as defined in the Uniform System of Accounts, 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 periods and service lives used by other utilities, and the service life estimates previously used for the asset under depreciation accounting.

Amortization accounting is appropriate for certain General Plant accounts that represent numerous units of property, but a very small portion of total depreciable electric plant in service. The accounts and their amortization periods are as follows:

Account	Amortization Period, Years
391.10, Office Furniture	25
391.15, Office Equipment	20
391.20, Personal Computers	5
391.25, Information Systems	5
393.00, Stores Equipment	30
394.00, Tools, Shop and Garage Equipment	25
395.00, Laboratory Equipment	20
397.00, Communication Equipment	20
398.00, Miscellaneous Equipment	20

For the purpose of calculating annual amortization amounts as of June 30, 2022, the book depreciation reserve for each plant account or subaccount is assigned or

allocated to vintages. The book reserve assigned to vintages with an age greater than the amortization period is equal to the vintage's original cost. The remaining book reserve is allocated among vintages with an age less than the amortization period in proportion to the calculated accrued amortization. The calculated accrued amortization is equal to the original cost multiplied by the ratio of the vintage's age to its amortization period. The annual amortization amount is determined by dividing the future amortizations (original cost less allocated book reserve) by the remaining period of amortization for the vintage.

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 remaining 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 to the electric distribution plant in service as of June 30, 2022. For most plant accounts, the application of such rates to future balances that reflect additions subsequent to June 30, 2022, is reasonable for a period of three to five years.

DESCRIPTION OF STATISTICAL SUPPORT

The service life estimates were based on judgment which incorporated statistical analyses of retirement data, discussions with management and consideration of estimates made for other electric utility companies. The results of the statistical analyses of service life are presented in the section titled "Service Life Statistics".

The estimated survivor curves for each account are presented in graphical form. The charts depict the estimated smooth survivor curve and original survivor curve(s), when applicable, related to each specific group. For groups where the original survivor curve was plotted, the calculation of the original life table is also presented.

DESCRIPTION OF DEPRECIATION TABULATIONS

Table 1 summarizes the results of the study, as applied to the original cost of electric plant as of June 30, 2022, is presented on pages VI-4 and VI-5 of this report. The schedule sets forth the original cost, the book reserve, future accruals, the calculated annual depreciation rate and amount, and the composite remaining life related to electric plant. Table 2 sets forth the five-year net salvage data for the period, 2017-2021, which is the basis for the net salvage normalization component of the depreciation accrual rate.

The tables of the calculated annual depreciation accruals are presented in account sequence in the section titled "Detailed Depreciation Calculations." 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.

JERSEY CENTRAL POWER & LIGHT COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE, CALCULATED ANNUAL DEPRECIATION RATES AND ACCRUALS AND NET SALVAGE NORMALIZATION RELATED TO ELECTRIC PLANT AS OF JUNE 30, 2022

	ACCOUNT	SURVIVOR CURVE	ORIGINAL COST AS OF JUNE 30, 2022	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE	NET SALVAGE NORMALIZATION ACCRUAL AMOUNT	NET SALVAGE NORMALIZATION ACCRUAL RATE	TOTAL ACCRUAL AMOUNT	TOTAL ACCRUAL RATE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(6)/(3)	(8)=(5)/(6)	(9)	(10)=(9)/(3)	(11)=(6)+(9)	(12)=(11)/(3)
	ELECTRIC PLANT											
	MISCELLANEOUS INTANGIBLE PLANT											
303.00	MISCELLANEOUS INTANGIBLE PLANT											
	FULLY ACCRUED		72,135,854.62	72,135,855	0	0	-	-	0	-	0	-
	AMORTIZED	7-SQ	61,432,256.15	31,260,750	30,171,506	8,612,677	*	3.5	0	-	8,612,677	*
	TOTAL MISCELLANEOUS INTANGIBLE PLANT		133,568,110.77	103,396,605	30,171,506	8,612,677			0	-	8,612,677	
	TOTAL MISCELLANEOUS INTANGIBLE PLANT		**133,568,110.77**	**103,396,605**	**30,171,506**	**8,612,677**			**0**	**-**	**8,612,677**	
	DISTRIBUTION PLANT											
360.12	DISTRIBUTION SUBSTATION EASEMENTS	85-R4	690,806.44	196,232	494,574	7,494	1.08	66.0	0	-	7,494	1.08
360.22	DISTRIBUTION LINE EASEMENTS	85-R4	26,255,822.88	18,658,017	7,597,806	141,991	0.54	53.5	0	-	141,991	0.54
361.10	STRUCTURES AND IMPROVEMENTS	75-R4	26,988,132.97	12,691,941	14,296,192	265,283	0.98	53.9	36,685	0.14	301,968	1.12
361.20	STRUCTURES AND IMPROVEMENTS - CLEARING	75-R4	64,044,190.99	3,825,158	60,219,033	837,809	1.31	71.9	0	-	837,809	1.31
362.00	STATION EQUIPMENT	59-R2	576,435,754.65	204,775,573	371,660,182	8,528,787	1.48	43.6	1,017,253	0.18	9,546,040	1.66
364.00	POLES, TOWERS AND FIXTURES	50-R1.5	800,508,801.13	282,470,467	518,038,334	13,689,173	1.71	37.8	6,740,017	0.84	20,429,190	2.55
365.00	OVERHEAD CONDUCTORS AND DEVICES	36-R0.5	1,022,785,987.63	131,214,812	891,571,176	32,960,526	3.22	27.0	9,314,562	0.91	42,275,088	4.13
365.10	OVERHEAD CONDUCTORS AND DEVICES - CLEARING	70-R5	208,194,285.07	42,022,543	166,171,742	2,861,456	1.37	58.1	0	-	2,861,456	1.37
366.00	UNDERGROUND CONDUIT	80-R4	123,040,108.15	62,338,783	60,701,325	1,119,225	0.91	54.2	97,001	0.08	1,216,226	0.99
367.00	UNDERGROUND CONDUCTORS AND DEVICES	47-R1.5	666,580,954.34	231,758,703	434,822,251	11,622,596	1.74	37.4	1,953,891	0.29	13,576,487	2.04
368.00	LINE TRANSFORMERS	42-R1	888,357,192.90	306,479,004	581,878,189	18,510,275	2.08	31.4	1,454,968	0.16	19,965,243	2.25
369.00	SERVICES	65-R2	480,062,882.98	188,097,073	291,965,810	6,667,379	1.39	43.8	2,116,014	0.44	8,783,393	1.83
370.00	METERS	23-R1	191,634,445.65	60,124,048	131,510,398	7,803,322	4.07	16.9	3,114,986	1.63	10,918,308	5.70
370.10	SMART METERS	20-S2.5	7,719,088.01	283,781	7,435,307	384,038	4.98	19.4	0	-	384,038	4.98
371.00	INSTALLATIONS ON CUSTOMERS' PREMISES	30-R2	27,065,403.65	9,357,374	17,708,030	1,165,916	4.31	15.2	137,466	0.51	1,303,382	4.82
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	30-R1.5	252,602,837.12	95,298,265	157,304,572	7,339,576	2.91	21.4	1,120,319	0.44	8,459,895	3.35
373.30	STREET LIGHTING AND SIGNAL SYSTEMS - LED	30-R1	2,212,833.06	62,925	2,149,908	75,145	3.40	28.6	1,376	0.06	76,521	3.46
	TOTAL DISTRIBUTION PLANT		**5,365,179,527.62**	**1,649,654,699**	**3,715,524,829**	**113,979,991**	**2.12**	**32.6**	**27,104,538**	**0.51**	**141,084,529**	**2.63**
	GENERAL PLANT											
389.20	LAND RIGHTS	50-R3	12,724.68	6,637	6,088	471	3.70	12.9	0	-	471	3.70
390.10	STRUCTURES AND IMPROVEMENTS	50-S0	86,872,045.16	45,724,071	41,147,974	1,139,752	1.31	36.1	202,360	0.23	1,342,112	1.54
390.20	STRUCTURES AND IMPROVEMENTS - CLEARING	65-R2.5	12,019,543.31	10,052,821	1,966,722	45,832	0.38	42.9	0	-	45,832	0.38
	OFFICE FURNITURE AND EQUIPMENT											
391.10	OFFICE FURNITURE	25-SQ	9,861,487.27	6,588,840	3,272,647	394,383	4.00	8.3	0	-	394,383	4.00
391.15	OFFICE EQUIPMENT	FULLY ACCRUED	2,471,673.48	2,471,673	0	0 **	-	-	0	-	0	-
391.20	PERSONAL COMPUTERS											
	FULLY ACCRUED		702,940.81	702,941	0	0	-	-	0	-	0	-
	AMORTIZED	5-SQ	13,978,264.09	5,679,950	8,298,314	2,796,170	20.00	3.0	0	-	2,796,170	20.00
	TOTAL PERSONAL COMPUTERS		14,681,204.90	6,382,891	8,298,314	2,796,170	19.05		0	-	2,796,170	19.05
391.25	INFORMATION SYSTEMS	FULLY ACCRUED	16,670.54	16,671	0	0 ***	-	-	0	-	0	-
	TOTAL OFFICE FURNITURE AND EQUIPMENT		27,031,036.19	15,460,075	11,570,961	3,190,553	11.80		0	-	3,190,553	11.80
392.00	TRANSPORTATION EQUIPMENT	12-S1	16,663,914.04	3,031,579	13,632,335	1,614,516	9.69	8.4	(293)	(0.00)	1,614,223	9.69
393.00	STORES EQUIPMENT	30-SQ	1,225,430.67	1,012,200	213,231	40,830	3.33	5.2	0	-	40,830	3.33
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	25-SQ	23,706,028.30	10,692,685	13,013,343	949,098	4.00	13.7	0	-	949,098	4.00
395.00	LABORATORY EQUIPMENT	FULLY ACCRUED	443,178.52	443,179	0	0 ****	-	-	0	-	0	-
396.00	POWER OPERATED EQUIPMENT	21-S1	3,624,331.46	2,769,446	854,885	111,016	3.06	7.7	(4,270)	0.12	106,746	2.95
397.00	COMMUNICATION EQUIPMENT											
	FULLY ACCRUED		127,353.64	127,354	0	0	-	-	0	-	0	-
	AMORTIZED	20-SQ	63,825,205.39	11,225,075	52,600,130	3,194,160	5.00	16.5	0	-	3,194,160	5.00
	TOTAL COMMUNICATION EQUIPMENT		63,952,559.03	11,352,429	52,600,130	3,194,160	4.99		0	-	3,194,160	4.99
398.00	MISCELLANEOUS EQUIPMENT											
	FULLY ACCRUED		7,862.55	7,863	0	0	-	-	0	-	0	-
	AMORTIZED	20-SQ	173,889.14	63,151	110,738	8,694	5.00	12.7	0	-	8,694	5.00
	TOTAL MISCELLANEOUS EQUIPMENT		181,751.69	71,014	110,738	8,694	4.78		0	-	8,694	4.78
	TOTAL GENERAL PLANT		**235,732,543.05**	**100,616,136**	**135,116,407**	**10,294,922**	**4.37**	**13.1**	**197,797**	**0.08**	**10,492,719**	**4.45**

JERSEY CENTRAL POWER & LIGHT COMPANY

TABLE 1. SUMMARY OF ESTIMATED SURVIVOR CURVE, ORIGINAL COST, BOOK DEPRECIATION RESERVE, CALCULATED ANNUAL DEPRECIATION RATES AND ACCRUALS AND NET SALVAGE NORMALIZATION RELATED TO ELECTRIC PLANT AS OF JUNE 30, 2022

	ACCOUNT	SURVIVOR CURVE	ORIGINAL COST AS OF JUNE 30, 2022	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT		CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE	NET SALVAGE NORMALIZATION ACCRUAL AMOUNT	NET SALVAGE NORMALIZATION ACCRUAL RATE	TOTAL ACCRUAL AMOUNT	TOTAL ACCRUAL RATE
	(1)	(2)	(3)	(4)	(5)	(6)		(7)=(6)/(3)	(8)=(5)/(6)	(9)	(10)=(9)/(3)	(11)=(6)+(9)	(12)=(11)/(3)
	UNRECOVERED RESERVE ADJUSTMENT FOR AMORTIZATION												
391.10	OFFICE FURNITURE			520,876		(130,219)	*****					(130,219)	
391.15	OFFICE EQUIPMENT			(194,529)		48,632	*****					48,632	
391.20	PERSONAL COMPUTERS			(9,136,503)		2,284,126	*****					2,284,126	
391.25	INFORMATION SYSTEMS			(821)		205	*****					205	
393.00	STORES EQUIPMENT			58,578		(14,645)	*****					(14,645)	
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT			(225,611)		56,403	*****					56,403	
397.00	COMMUNICATION EQUIPMENT			(1,028,521)		257,130	*****					257,130	
398.00	MISCELLANEOUS EQUIPMENT			112,304		(28,076)	*****					(28,076)	
	TOTAL UNRECOVERED RESERVE ADJUSTMENT FOR AMORTIZATION			**(9,894,227)**		**2,473,556**						**2,473,556**	
	TOTAL DEPRECIABLE ELECTRIC PLANT		**5,734,480,181.44**	**1,843,773,213**	**3,880,812,742**	**135,361,146**		**2.36**		**27,302,335**	**0.48**	**162,663,481**	**2.84**
	NONDEPRECIABLE PLANT												
301.00	ORGNAIZATION		56,399.61										
302.00	FRANCHISES AND CONSENTS		2,995.02										
360.11	LAND		5,699,009.30	84									
360.21	LAND		11,988.31										
374.00	ARC DISTRIBUTION PLANT		45,656.70	30,127									
389.10	LAND		1,467,829.14										
390.30	STRUCTURES AND IMPROVEMENTS - LEASEHOLDS		2,879,848.29	858,687									
397.10	COMMUNCATOIN EQUIPMENT - FIBER OPTIC		0.00	56,525									
399.10	ARC GENERAL PLANT		1,444,666.47	418,487									
	TOTAL NONDEPRECIABLE PLANT		**11,608,392.84**	**1,363,910**									
	TOTAL ELECTRIC PLANT		**5,746,088,574.28**	**1,845,137,123**									

* Assets are amortized individually using a 14.29% annual accrual rate consistent with a 7-year amortization period.
** Assets as of July 1, 2022 will utilize a 5.00% annual accrual rate consistent with the amortization period.
*** Assets as of July 1, 2022 will utilize a 20.00% annual accrual rate consistent with the amortization period.
**** Assets as of July 1, 2022 will utilize a 5.00% annual accrual rate consistent with the amortization period.
***** 4-Year amortization of unrecovered reserve related to amortization accounting.

NOTE: Assets added to Account 303.10 (Miscellaneous Intangible Plant - Cloud Assets) will be amortized over the life of the agreement.

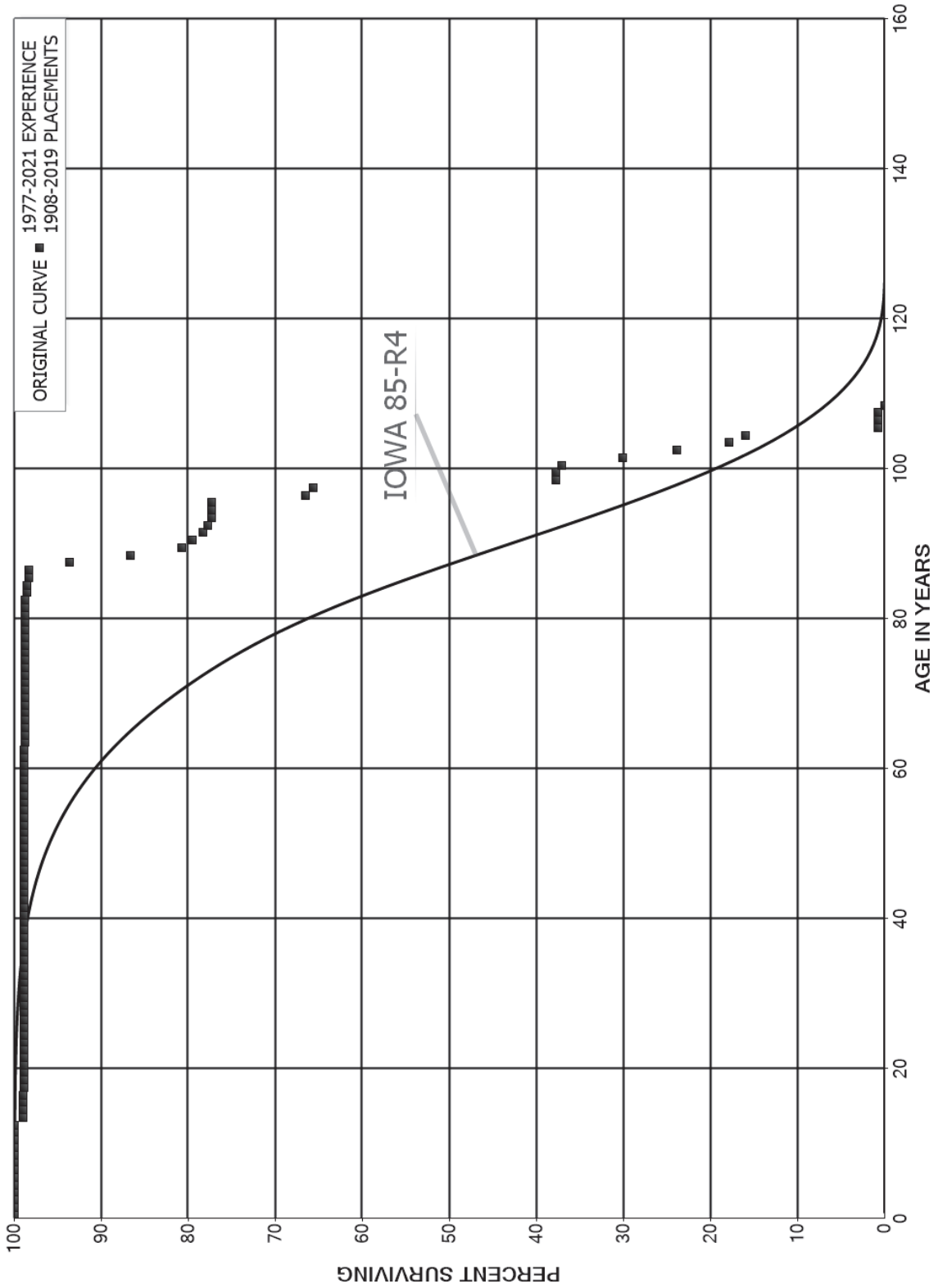
JERSEY CENTRAL POWER & LIGHT COMPANY

TABLE 2. 5-YEAR NET SALVAGE FOR NORMALIZATION

ACCOUNT	2017 COST OF REMOVAL	2017 GROSS SALVAGE	2018 COST OF REMOVAL	2018 GROSS SALVAGE	2019 COST OF REMOVAL	2019 GROSS SALVAGE	2020 COST OF REMOVAL	2020 GROSS SALVAGE	2021 COST OF REMOVAL	2021 GROSS SALVAGE	NET SALVAGE	SALVAGE ACCRUAL
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)=-(12)/5
361.10	145,623.69		18,067.58		221.68		198.87		19,310.79		(183,422.61)	36,685
362.00	443,556.59		468,608.39		1,064,625.89		2,225,937.78		883,538.18		(5,086,266.83)	1,017,253
364.00	2,853,179.22		16,719,031.53		3,391,332.91		5,180,607.86		5,555,933.92		(33,700,085.44)	6,740,017
365.00	4,983,058.57		15,737,259.83		6,515,427.31		10,010,762.47		9,326,301.00		(46,572,809.18)	9,314,562
366.00	27,011.30		76,994.33		155,660.58		131,261.65		94,074.83		(485,002.69)	97,001
367.00	1,703,236.52		1,601,660.11		2,142,679.98		2,283,784.55		2,038,092.51		(9,769,453.67)	1,953,891
368.00	1,235,092.17	62,215.69	1,115,035.50	86,803.89	1,484,834.23	65,851.44	2,115,336.43	73,784.01	1,613,196.82		(7,274,840.12)	1,454,968
369.00	1,317,156.93		1,055,907.57		1,265,289.63		3,653,086.16		3,288,629.28		(10,580,069.57)	2,116,014
370.00	3,090,475.87		2,665,632.99		2,945,911.84		3,071,356.47		3,801,550.85		(15,574,928.02)	3,114,986
371.00	140,195.80		84,804.33		204,535.51		170,387.94		87,408.47		(687,332.05)	137,466
373.00	1,549,715.66		666,739.85		1,233,079.54		1,474,955.08		677,104.45		(5,601,594.58)	1,120,319
373.30	213.69		745.01		322.81		4,308.60		1,287.39		(6,877.50)	1,376
390.10			507,987.15		62,227.97		246,976.72		194,607.79		(1,011,799.63)	202,360
392.00	(1,465.50)										1,465.50	(293)
396.00	(526.38)					1,358.10				19,463.50	21,347.98	(4,270)
TOTAL	**17,486,524.13**	**62,215.69**	**40,718,474.17**	**86,803.89**	**20,466,149.88**	**67,209.54**	**30,568,960.58**	**73,784.01**	**27,581,036.27**	**19,463.50**	**(136,511,668.40)**	**27,302,335**

PART VII. SERVICE LIFE STATISTICS

JERSEY CENTRAL POWER & LIGHT COMPANY
ACCOUNTS 360.12 AND 360.22 DISTRIBUTION SUBSTATION AND DISTRIBUTION LINE EASEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNTS 360.12 AND 360.22 DISTRIBUTION SUBSTATION AND DISTRIBUTION LINE EASEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1908-2019 EXPERIENCE BAND 1977-2021

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	21,933,686	0	0.0000	1.0000	100.00
0.5	22,350,169	14	0.0000	1.0000	100.00
1.5	22,826,187	16	0.0000	1.0000	100.00
2.5	22,914,661	2,141	0.0001	0.9999	100.00
3.5	23,334,991	18	0.0000	1.0000	99.99
4.5	23,619,785	10	0.0000	1.0000	99.99
5.5	23,991,814	14	0.0000	1.0000	99.99
6.5	24,256,291	18	0.0000	1.0000	99.99
7.5	24,551,764	42	0.0000	1.0000	99.99
8.5	24,819,550	61	0.0000	1.0000	99.99
9.5	25,085,004	64	0.0000	1.0000	99.99
10.5	25,322,291	55	0.0000	1.0000	99.99
11.5	25,537,958	49	0.0000	1.0000	99.99
12.5	25,724,937	282,503	0.0110	0.9890	99.99
13.5	25,606,855	57	0.0000	1.0000	98.89
14.5	25,368,614	81	0.0000	1.0000	98.89
15.5	25,307,587	66	0.0000	1.0000	98.89
16.5	25,438,465	127	0.0000	1.0000	98.89
17.5	25,537,881	109	0.0000	1.0000	98.89
18.5	25,605,446	62	0.0000	1.0000	98.89
19.5	25,663,105	62	0.0000	1.0000	98.89
20.5	25,712,759	88	0.0000	1.0000	98.89
21.5	24,086,055	117	0.0000	1.0000	98.89
22.5	24,106,722	360	0.0000	1.0000	98.89
23.5	22,826,070	91	0.0000	1.0000	98.89
24.5	22,483,845	98	0.0000	1.0000	98.89
25.5	22,228,887	85	0.0000	1.0000	98.89
26.5	21,581,219	100	0.0000	1.0000	98.89
27.5	20,985,280	86	0.0000	1.0000	98.88
28.5	19,400,544	106	0.0000	1.0000	98.88
29.5	17,779,622	94	0.0000	1.0000	98.88
30.5	16,299,845	170	0.0000	1.0000	98.88
31.5	15,295,491	110	0.0000	1.0000	98.88
32.5	14,614,750	117	0.0000	1.0000	98.88
33.5	13,548,536	183	0.0000	1.0000	98.88
34.5	12,780,307	134	0.0000	1.0000	98.88
35.5	11,531,760	115	0.0000	1.0000	98.88
36.5	10,888,624	107	0.0000	1.0000	98.88
37.5	9,194,147	100	0.0000	1.0000	98.88
38.5	8,367,240	241	0.0000	1.0000	98.88

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNTS 360.12 AND 360.22 DISTRIBUTION SUBSTATION AND DISTRIBUTION LINE EASEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1908-2019 EXPERIENCE BAND 1977-2021

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	8,033,696	88	0.0000	1.0000	98.87
40.5	7,535,311	92	0.0000	1.0000	98.87
41.5	6,866,116	78	0.0000	1.0000	98.87
42.5	6,078,107	64	0.0000	1.0000	98.87
43.5	5,485,936	54	0.0000	1.0000	98.87
44.5	5,071,038	32	0.0000	1.0000	98.87
45.5	4,569,256	29	0.0000	1.0000	98.87
46.5	4,233,603	24	0.0000	1.0000	98.87
47.5	3,819,116	26	0.0000	1.0000	98.87
48.5	3,536,555	29	0.0000	1.0000	98.86
49.5	3,169,313	26	0.0000	1.0000	98.86
50.5	2,914,337	22	0.0000	1.0000	98.86
51.5	2,617,083	26	0.0000	1.0000	98.86
52.5	2,349,818	124	0.0001	0.9999	98.86
53.5	2,076,409	20	0.0000	1.0000	98.86
54.5	1,652,231	31	0.0000	1.0000	98.86
55.5	1,431,431	14	0.0000	1.0000	98.85
56.5	1,240,169	10	0.0000	1.0000	98.85
57.5	1,069,298	52	0.0000	1.0000	98.85
58.5	923,506	18	0.0000	1.0000	98.85
59.5	811,694	31	0.0000	1.0000	98.85
60.5	702,599	34	0.0000	1.0000	98.84
61.5	599,420	31	0.0001	0.9999	98.84
62.5	520,175	462	0.0009	0.9991	98.83
63.5	460,783	93	0.0002	0.9998	98.74
64.5	413,770	10	0.0000	1.0000	98.72
65.5	391,878	5	0.0000	1.0000	98.72
66.5	373,688	5	0.0000	1.0000	98.72
67.5	357,198	7	0.0000	1.0000	98.72
68.5	338,635	7	0.0000	1.0000	98.72
69.5	320,336	16	0.0001	0.9999	98.71
70.5	305,840	18	0.0001	0.9999	98.71
71.5	294,593	3	0.0000	1.0000	98.70
72.5	280,774	20	0.0001	0.9999	98.70
73.5	270,389	4	0.0000	1.0000	98.70
74.5	261,387		0.0000	1.0000	98.69
75.5	247,529		0.0000	1.0000	98.69
76.5	243,594		0.0000	1.0000	98.69
77.5	239,868		0.0000	1.0000	98.69
78.5	219,234		0.0000	1.0000	98.69

JERSEY CENTRAL POWER & LIGHT COMPANY

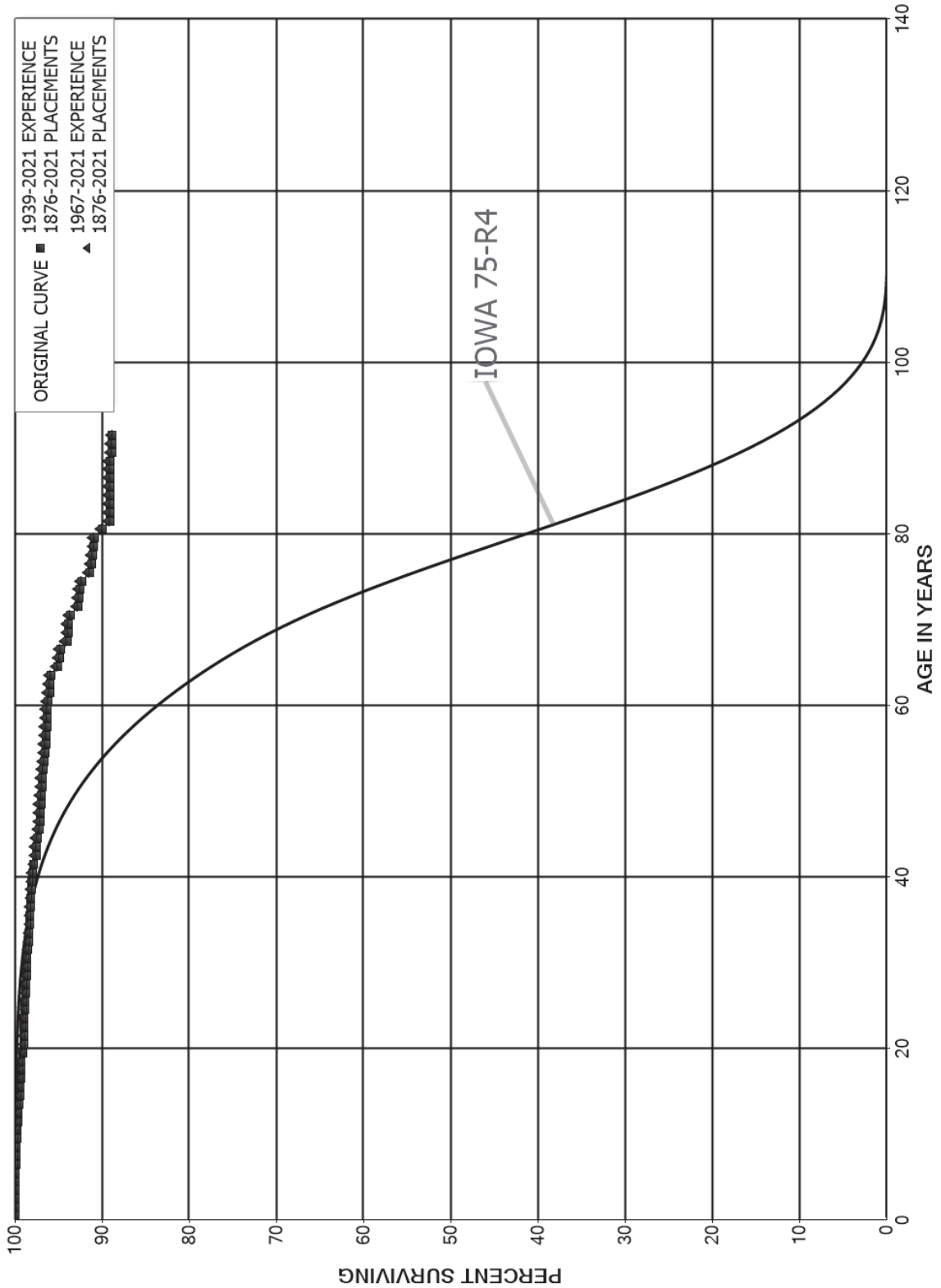
ACCOUNTS 360.12 AND 360.22 DISTRIBUTION SUBSTATION AND DISTRIBUTION LINE EASEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1908-2019 EXPERIENCE BAND 1977-2021

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	216,373		0.0000	1.0000	98.69
80.5	205,755		0.0000	1.0000	98.69
81.5	196,121		0.0000	1.0000	98.69
82.5	187,993	256	0.0014	0.9986	98.69
83.5	50,952		0.0000	1.0000	98.56
84.5	49,861	159	0.0032	0.9968	98.56
85.5	47,349		0.0000	1.0000	98.25
86.5	46,426	2,198	0.0473	0.9527	98.25
87.5	43,150	3,207	0.0743	0.9257	93.60
88.5	38,568	2,645	0.0686	0.9314	86.64
89.5	34,654	528	0.0152	0.9848	80.70
90.5	31,156	483	0.0155	0.9845	79.47
91.5	28,058	173	0.0062	0.9938	78.24
92.5	27,885	184	0.0066	0.9934	77.75
93.5	27,701		0.0000	1.0000	77.24
94.5	27,701		0.0000	1.0000	77.24
95.5	27,701	3,835	0.1384	0.8616	77.24
96.5	23,866	344	0.0144	0.9856	66.55
97.5	23,522	10,000	0.4251	0.5749	65.59
98.5	13,522		0.0000	1.0000	37.71
99.5	13,522	232	0.0171	0.9829	37.71
100.5	13,291	2,503	0.1883	0.8117	37.06
101.5	10,788	2,225	0.2062	0.7938	30.08
102.5	8,564	2,161	0.2524	0.7476	23.88
103.5	6,402	673	0.1051	0.8949	17.85
104.5	5,729	5,454	0.9520	0.0480	15.98
105.5	275		0.0000	1.0000	0.77
106.5	275		0.0000	1.0000	0.77
107.5	275	275	1.0000		0.77
108.5					

JERSEY CENTRAL POWER & LIGHT COMPANY
ACCOUNT 361.10 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 361.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1876-2021 EXPERIENCE BAND 1939-2021

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	15,371,939	0	0.0000	1.0000	100.00
0.5	16,672,053	0	0.0000	1.0000	100.00
1.5	18,236,019	320	0.0000	1.0000	100.00
2.5	16,556,289	25	0.0000	1.0000	100.00
3.5	16,700,088	230	0.0000	1.0000	100.00
4.5	16,662,696	1,453	0.0001	0.9999	100.00
5.5	15,589,485	24,072	0.0015	0.9985	99.99
6.5	15,251,121	5,564	0.0004	0.9996	99.83
7.5	15,539,197	1,830	0.0001	0.9999	99.80
8.5	16,544,337	5,006	0.0003	0.9997	99.79
9.5	16,600,881	1,178	0.0001	0.9999	99.76
10.5	17,029,464	20,502	0.0012	0.9988	99.75
11.5	17,311,579	4,294	0.0002	0.9998	99.63
12.5	17,337,772	10,786	0.0006	0.9994	99.60
13.5	16,707,274	20,129	0.0012	0.9988	99.54
14.5	16,162,656	11,122	0.0007	0.9993	99.42
15.5	15,814,447	13,164	0.0008	0.9992	99.35
16.5	14,425,532	2,429	0.0002	0.9998	99.27
17.5	14,482,669	2,676	0.0002	0.9998	99.25
18.5	14,562,820	31,579	0.0022	0.9978	99.24
19.5	14,623,048	3,134	0.0002	0.9998	99.02
20.5	14,527,631	4,386	0.0003	0.9997	99.00
21.5	14,727,392	10,077	0.0007	0.9993	98.97
22.5	14,945,808	1,660	0.0001	0.9999	98.90
23.5	15,008,615	11,320	0.0008	0.9992	98.89
24.5	15,122,513	1,329	0.0001	0.9999	98.82
25.5	13,997,731	6,226	0.0004	0.9996	98.81
26.5	13,355,685	3,285	0.0002	0.9998	98.76
27.5	13,226,961	10,645	0.0008	0.9992	98.74
28.5	12,990,177	4,640	0.0004	0.9996	98.66
29.5	10,727,216	5,015	0.0005	0.9995	98.62
30.5	10,568,464	5,532	0.0005	0.9995	98.58
31.5	10,480,318	8,965	0.0009	0.9991	98.53
32.5	8,943,042	6,619	0.0007	0.9993	98.44
33.5	8,327,813	3,296	0.0004	0.9996	98.37
34.5	7,712,176	5,316	0.0007	0.9993	98.33
35.5	6,994,052	2,785	0.0004	0.9996	98.26
36.5	6,761,227	4,795	0.0007	0.9993	98.22
37.5	6,593,966	3,104	0.0005	0.9995	98.15
38.5	6,551,072	3,610	0.0006	0.9994	98.11

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 361.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1876-2021 EXPERIENCE BAND 1939-2021

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	6,360,095	5,976	0.0009	0.9991	98.05
40.5	6,368,683	11,734	0.0018	0.9982	97.96
41.5	6,337,540	16,298	0.0026	0.9974	97.78
42.5	6,201,327	2,600	0.0004	0.9996	97.53
43.5	6,069,348	6,997	0.0012	0.9988	97.49
44.5	5,963,699	10,929	0.0018	0.9982	97.38
45.5	5,823,236	7,616	0.0013	0.9987	97.20
46.5	5,457,981	1,199	0.0002	0.9998	97.07
47.5	5,306,889	3,109	0.0006	0.9994	97.05
48.5	5,029,143	3,592	0.0007	0.9993	96.99
49.5	4,756,244	2,684	0.0006	0.9994	96.92
50.5	4,207,102	3,512	0.0008	0.9992	96.87
51.5	3,645,996	2,924	0.0008	0.9992	96.79
52.5	3,121,677	4,584	0.0015	0.9985	96.71
53.5	2,691,140	1,134	0.0004	0.9996	96.57
54.5	2,435,854	2,429	0.0010	0.9990	96.53
55.5	2,158,851	1,712	0.0008	0.9992	96.43
56.5	2,015,763	837	0.0004	0.9996	96.35
57.5	1,825,241	267	0.0001	0.9999	96.31
58.5	1,691,613	1,059	0.0006	0.9994	96.30
59.5	1,519,708	1,673	0.0011	0.9989	96.24
60.5	1,419,317	2,017	0.0014	0.9986	96.13
61.5	1,306,927	220	0.0002	0.9998	96.00
62.5	1,190,197	2,257	0.0019	0.9981	95.98
63.5	1,086,432	8,228	0.0076	0.9924	95.80
64.5	995,827	2,031	0.0020	0.9980	95.07
65.5	807,297	945	0.0012	0.9988	94.88
66.5	646,857	5,195	0.0080	0.9920	94.77
67.5	592,420	1,086	0.0018	0.9982	94.01
68.5	502,219	198	0.0004	0.9996	93.84
69.5	576,716	1,340	0.0023	0.9977	93.80
70.5	534,423	4,991	0.0093	0.9907	93.58
71.5	404,303	352	0.0009	0.9991	92.71
72.5	390,135	589	0.0015	0.9985	92.63
73.5	445,433	1,149	0.0026	0.9974	92.49
74.5	410,436	3,844	0.0094	0.9906	92.25
75.5	407,309	1,154	0.0028	0.9972	91.38
76.5	409,662	265	0.0006	0.9994	91.12
77.5	412,901	797	0.0019	0.9981	91.07
78.5	405,153	73	0.0002	0.9998	90.89

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 361.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1876-2021 EXPERIENCE BAND 1939-2021

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	413,548	4,128	0.0100	0.9900	90.87
80.5	407,168	4,108	0.0101	0.9899	89.97
81.5	386,944	16	0.0000	1.0000	89.06
82.5	385,504	3	0.0000	1.0000	89.06
83.5	383,772	3	0.0000	1.0000	89.05
84.5	382,783		0.0000	1.0000	89.05
85.5	382,775	3	0.0000	1.0000	89.05
86.5	382,665	130	0.0003	0.9997	89.05
87.5	382,460	14	0.0000	1.0000	89.02
88.5	381,345	711	0.0019	0.9981	89.02
89.5	376,971	18	0.0000	1.0000	88.85
90.5	351,274	272	0.0008	0.9992	88.85
91.5	227,014	546	0.0024	0.9976	88.78
92.5	223,081		0.0000	1.0000	88.57
93.5	210,960	412	0.0020	0.9980	88.57
94.5	189,961	38	0.0002	0.9998	88.39
95.5	105,180	2,278	0.0217	0.9783	88.38
96.5	83,452		0.0000	1.0000	86.46
97.5	78,302	42	0.0005	0.9995	86.46
98.5	62,110	4	0.0001	0.9999	86.42
99.5	66,783	802	0.0120	0.9880	86.41
100.5	66,898	112	0.0017	0.9983	85.37
101.5	66,588		0.0000	1.0000	85.23
102.5	66,299	302	0.0046	0.9954	85.23
103.5	65,950	28	0.0004	0.9996	84.84
104.5	65,871	1,885	0.0286	0.9714	84.81
105.5	63,969		0.0000	1.0000	82.38
106.5	63,895		0.0000	1.0000	82.38
107.5	63,844		0.0000	1.0000	82.38
108.5	63,844		0.0000	1.0000	82.38
109.5	54,307		0.0000	1.0000	82.38
110.5	54,127		0.0000	1.0000	82.38
111.5	52,688		0.0000	1.0000	82.38
112.5	52,688		0.0000	1.0000	82.38
113.5	52,688		0.0000	1.0000	82.38
114.5	52,688		0.0000	1.0000	82.38
115.5	52,688		0.0000	1.0000	82.38
116.5	26,579		0.0000	1.0000	82.38
117.5	26,579		0.0000	1.0000	82.38
118.5	26,579		0.0000	1.0000	82.38

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 361.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1876-2021 EXPERIENCE BAND 1939-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
119.5	26,579	961	0.0362	0.9638	82.38
120.5	18,606		0.0000	1.0000	79.40
121.5	17,539		0.0000	1.0000	79.40
122.5	17,539	57	0.0032	0.9968	79.40
123.5	17,482	5	0.0003	0.9997	79.14
124.5	17,477	955	0.0546	0.9454	79.12
125.5	1,222		0.0000	1.0000	74.80
126.5	1,218		0.0000	1.0000	74.80
127.5	1,217		0.0000	1.0000	74.80
128.5	1,217		0.0000	1.0000	74.80
129.5	1,217		0.0000	1.0000	74.80
130.5	1,217		0.0000	1.0000	74.80
131.5	1,217		0.0000	1.0000	74.80
132.5	1,217		0.0000	1.0000	74.80
133.5	1,217		0.0000	1.0000	74.80
134.5	1,217		0.0000	1.0000	74.80
135.5	1,217		0.0000	1.0000	74.80
136.5	1,217		0.0000	1.0000	74.80
137.5	1,217		0.0000	1.0000	74.80
138.5	1,217		0.0000	1.0000	74.80
139.5	1,217		0.0000	1.0000	74.80
140.5	1,217		0.0000	1.0000	74.80
141.5	1,217		0.0000	1.0000	74.80
142.5	1,217		0.0000	1.0000	74.80
143.5	1,217		0.0000	1.0000	74.80
144.5	1,217		0.0000	1.0000	74.80
145.5					74.80

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 361.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1876-2021 EXPERIENCE BAND 1967-2021

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	14,680,008	0	0.0000	1.0000	100.00
0.5	15,963,039	0	0.0000	1.0000	100.00
1.5	17,408,385		0.0000	1.0000	100.00
2.5	15,735,378	25	0.0000	1.0000	100.00
3.5	15,874,939	230	0.0000	1.0000	100.00
4.5	15,925,192	1,430	0.0001	0.9999	100.00
5.5	14,837,200	22,972	0.0015	0.9985	99.99
6.5	14,545,482	3,070	0.0002	0.9998	99.83
7.5	14,841,697	530	0.0000	1.0000	99.81
8.5	15,907,629	4,268	0.0003	0.9997	99.81
9.5	15,996,791	726	0.0000	1.0000	99.78
10.5	16,567,478	19,643	0.0012	0.9988	99.78
11.5	16,886,675	3,500	0.0002	0.9998	99.66
12.5	16,930,246	10,291	0.0006	0.9994	99.64
13.5	16,387,791	20,089	0.0012	0.9988	99.58
14.5	15,897,300	9,830	0.0006	0.9994	99.46
15.5	15,620,375	13,164	0.0008	0.9992	99.40
16.5	14,291,563	2,253	0.0002	0.9998	99.31
17.5	14,355,359	2,676	0.0002	0.9998	99.30
18.5	14,450,128	31,333	0.0022	0.9978	99.28
19.5	14,532,663	1,865	0.0001	0.9999	99.06
20.5	14,434,740	4,386	0.0003	0.9997	99.05
21.5	14,635,075	9,954	0.0007	0.9993	99.02
22.5	14,852,914	1,660	0.0001	0.9999	98.95
23.5	14,924,169	11,308	0.0008	0.9992	98.94
24.5	15,042,678	1,081	0.0001	0.9999	98.87
25.5	13,926,272	6,070	0.0004	0.9996	98.86
26.5	13,280,787	3,285	0.0002	0.9998	98.82
27.5	13,157,838	10,502	0.0008	0.9992	98.79
28.5	12,916,318	4,099	0.0003	0.9997	98.71
29.5	10,650,772	4,621	0.0004	0.9996	98.68
30.5	10,471,343	4,848	0.0005	0.9995	98.64
31.5	10,380,570	6,127	0.0006	0.9994	98.59
32.5	8,844,937	5,266	0.0006	0.9994	98.53
33.5	8,221,505	3,296	0.0004	0.9996	98.48
34.5	7,605,281	4,975	0.0007	0.9993	98.44
35.5	6,891,112	1,847	0.0003	0.9997	98.37
36.5	6,662,172	4,170	0.0006	0.9994	98.35
37.5	6,506,014	3,089	0.0005	0.9995	98.28
38.5	6,475,869	3,610	0.0006	0.9994	98.24

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 361.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1876-2021 EXPERIENCE BAND 1967-2021

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	6,304,248	3,068	0.0005	0.9995	98.18
40.5	6,325,185	10,814	0.0017	0.9983	98.14
41.5	6,297,116	5,328	0.0008	0.9992	97.97
42.5	6,174,964	2,600	0.0004	0.9996	97.88
43.5	6,059,148	6,997	0.0012	0.9988	97.84
44.5	5,954,470	10,929	0.0018	0.9982	97.73
45.5	5,814,382	7,616	0.0013	0.9987	97.55
46.5	5,445,111	1,199	0.0002	0.9998	97.42
47.5	5,294,018	3,109	0.0006	0.9994	97.40
48.5	5,016,273	3,592	0.0007	0.9993	97.34
49.5	4,743,374	2,239	0.0005	0.9995	97.27
50.5	4,194,677	3,512	0.0008	0.9992	97.23
51.5	3,633,571	2,924	0.0008	0.9992	97.15
52.5	3,105,431	4,584	0.0015	0.9985	97.07
53.5	2,674,893	1,134	0.0004	0.9996	96.93
54.5	2,423,722	2,429	0.0010	0.9990	96.88
55.5	2,151,014	1,712	0.0008	0.9992	96.79
56.5	2,011,942	837	0.0004	0.9996	96.71
57.5	1,821,419	267	0.0001	0.9999	96.67
58.5	1,687,791	1,059	0.0006	0.9994	96.66
59.5	1,515,887	1,673	0.0011	0.9989	96.60
60.5	1,415,496	2,017	0.0014	0.9986	96.49
61.5	1,306,927	220	0.0002	0.9998	96.35
62.5	1,190,197	2,257	0.0019	0.9981	96.34
63.5	1,086,432	8,228	0.0076	0.9924	96.15
64.5	995,827	2,031	0.0020	0.9980	95.42
65.5	807,297	945	0.0012	0.9988	95.23
66.5	646,857	5,195	0.0080	0.9920	95.12
67.5	592,420	1,086	0.0018	0.9982	94.35
68.5	502,219	198	0.0004	0.9996	94.18
69.5	576,716	1,340	0.0023	0.9977	94.14
70.5	534,423	4,991	0.0093	0.9907	93.93
71.5	404,303	352	0.0009	0.9991	93.05
72.5	390,135	589	0.0015	0.9985	92.97
73.5	445,433	1,149	0.0026	0.9974	92.83
74.5	410,436	3,844	0.0094	0.9906	92.59
75.5	407,309	1,154	0.0028	0.9972	91.72
76.5	409,662	265	0.0006	0.9994	91.46
77.5	412,901	797	0.0019	0.9981	91.40
78.5	405,153	73	0.0002	0.9998	91.23

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 361.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1876-2021 EXPERIENCE BAND 1967-2021

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	413,548	4,128	0.0100	0.9900	91.21
80.5	407,168	4,108	0.0101	0.9899	90.30
81.5	386,944	16	0.0000	1.0000	89.39
82.5	385,504	3	0.0000	1.0000	89.38
83.5	383,772	3	0.0000	1.0000	89.38
84.5	382,783		0.0000	1.0000	89.38
85.5	382,775	3	0.0000	1.0000	89.38
86.5	382,665	130	0.0003	0.9997	89.38
87.5	382,460	14	0.0000	1.0000	89.35
88.5	381,345	711	0.0019	0.9981	89.35
89.5	376,971	18	0.0000	1.0000	89.18
90.5	351,274	272	0.0008	0.9992	89.18
91.5	227,014	546	0.0024	0.9976	89.11
92.5	223,081		0.0000	1.0000	88.89
93.5	210,960	412	0.0020	0.9980	88.89
94.5	189,961	38	0.0002	0.9998	88.72
95.5	105,180	2,278	0.0217	0.9783	88.70
96.5	83,452		0.0000	1.0000	86.78
97.5	78,302	42	0.0005	0.9995	86.78
98.5	62,110	4	0.0001	0.9999	86.73
99.5	66,783	802	0.0120	0.9880	86.73
100.5	66,898	112	0.0017	0.9983	85.69
101.5	66,588		0.0000	1.0000	85.54
102.5	66,299	302	0.0046	0.9954	85.54
103.5	65,950	28	0.0004	0.9996	85.15
104.5	65,871	1,885	0.0286	0.9714	85.12
105.5	63,969		0.0000	1.0000	82.68
106.5	63,895		0.0000	1.0000	82.68
107.5	63,844		0.0000	1.0000	82.68
108.5	63,844		0.0000	1.0000	82.68
109.5	54,307		0.0000	1.0000	82.68
110.5	54,127		0.0000	1.0000	82.68
111.5	52,688		0.0000	1.0000	82.68
112.5	52,688		0.0000	1.0000	82.68
113.5	52,688		0.0000	1.0000	82.68
114.5	52,688		0.0000	1.0000	82.68
115.5	52,688		0.0000	1.0000	82.68
116.5	26,579		0.0000	1.0000	82.68
117.5	26,579		0.0000	1.0000	82.68
118.5	26,579		0.0000	1.0000	82.68

JERSEY CENTRAL POWER & LIGHT COMPANY

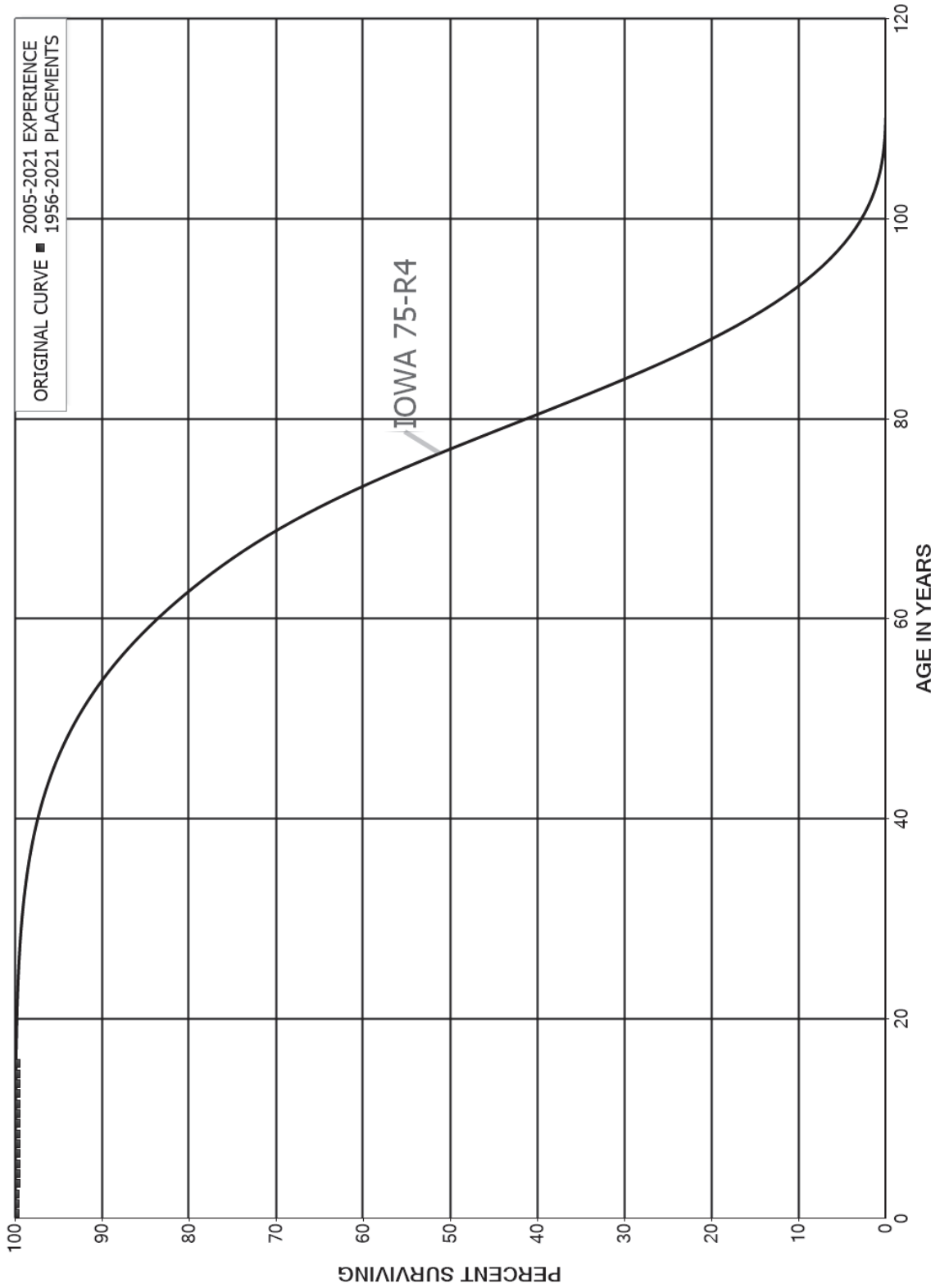
ACCOUNT 361.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1876-2021 EXPERIENCE BAND 1967-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
119.5	26,579	961	0.0362	0.9638	82.68
120.5	18,606		0.0000	1.0000	79.69
121.5	17,539		0.0000	1.0000	79.69
122.5	17,539	57	0.0032	0.9968	79.69
123.5	17,482	5	0.0003	0.9997	79.44
124.5	17,477	955	0.0546	0.9454	79.41
125.5	1,222		0.0000	1.0000	75.07
126.5	1,218		0.0000	1.0000	75.07
127.5	1,217		0.0000	1.0000	75.07
128.5	1,217		0.0000	1.0000	75.07
129.5	1,217		0.0000	1.0000	75.07
130.5	1,217		0.0000	1.0000	75.07
131.5	1,217		0.0000	1.0000	75.07
132.5	1,217		0.0000	1.0000	75.07
133.5	1,217		0.0000	1.0000	75.07
134.5	1,217		0.0000	1.0000	75.07
135.5	1,217		0.0000	1.0000	75.07
136.5	1,217		0.0000	1.0000	75.07
137.5	1,217		0.0000	1.0000	75.07
138.5	1,217		0.0000	1.0000	75.07
139.5	1,217		0.0000	1.0000	75.07
140.5	1,217		0.0000	1.0000	75.07
141.5	1,217		0.0000	1.0000	75.07
142.5	1,217		0.0000	1.0000	75.07
143.5	1,217		0.0000	1.0000	75.07
144.5	1,217		0.0000	1.0000	75.07
145.5					75.07

JERSEY CENTRAL POWER & LIGHT COMPANY
ACCOUNT 361.20 STRUCTURES AND IMPROVEMENTS - CLEARING
ORIGINAL AND SMOOTH SURVIVOR CURVES



JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 361.20 STRUCTURES AND IMPROVEMENTS - CLEARING

ORIGINAL LIFE TABLE

PLACEMENT BAND 1956-2021 EXPERIENCE BAND 2005-2021

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	64,168,515		0.0000	1.0000	100.00
0.5	63,594,645		0.0000	1.0000	100.00
1.5	15,214,829		0.0000	1.0000	100.00
2.5	13,805,606	26,402	0.0019	0.9981	100.00
3.5	13,779,204		0.0000	1.0000	99.81
4.5	13,779,204		0.0000	1.0000	99.81
5.5	4,316,020		0.0000	1.0000	99.81
6.5	4,316,020		0.0000	1.0000	99.81
7.5	1,988,438		0.0000	1.0000	99.81
8.5	1,988,438		0.0000	1.0000	99.81
9.5	1,412,175		0.0000	1.0000	99.81
10.5	1,412,175		0.0000	1.0000	99.81
11.5	1,246,482		0.0000	1.0000	99.81
12.5	1,056,674		0.0000	1.0000	99.81
13.5	991,549		0.0000	1.0000	99.81
14.5	66,893		0.0000	1.0000	99.81
15.5					99.81
16.5					
17.5					
18.5					
19.5					
20.5					
21.5					
22.5					
23.5					
24.5					
25.5					
26.5					
27.5					
28.5					
29.5					
30.5					
31.5					
32.5					
33.5					
34.5					
35.5					
36.5					
37.5					
38.5					

JERSEY CENTRAL POWER & LIGHT COMPANY

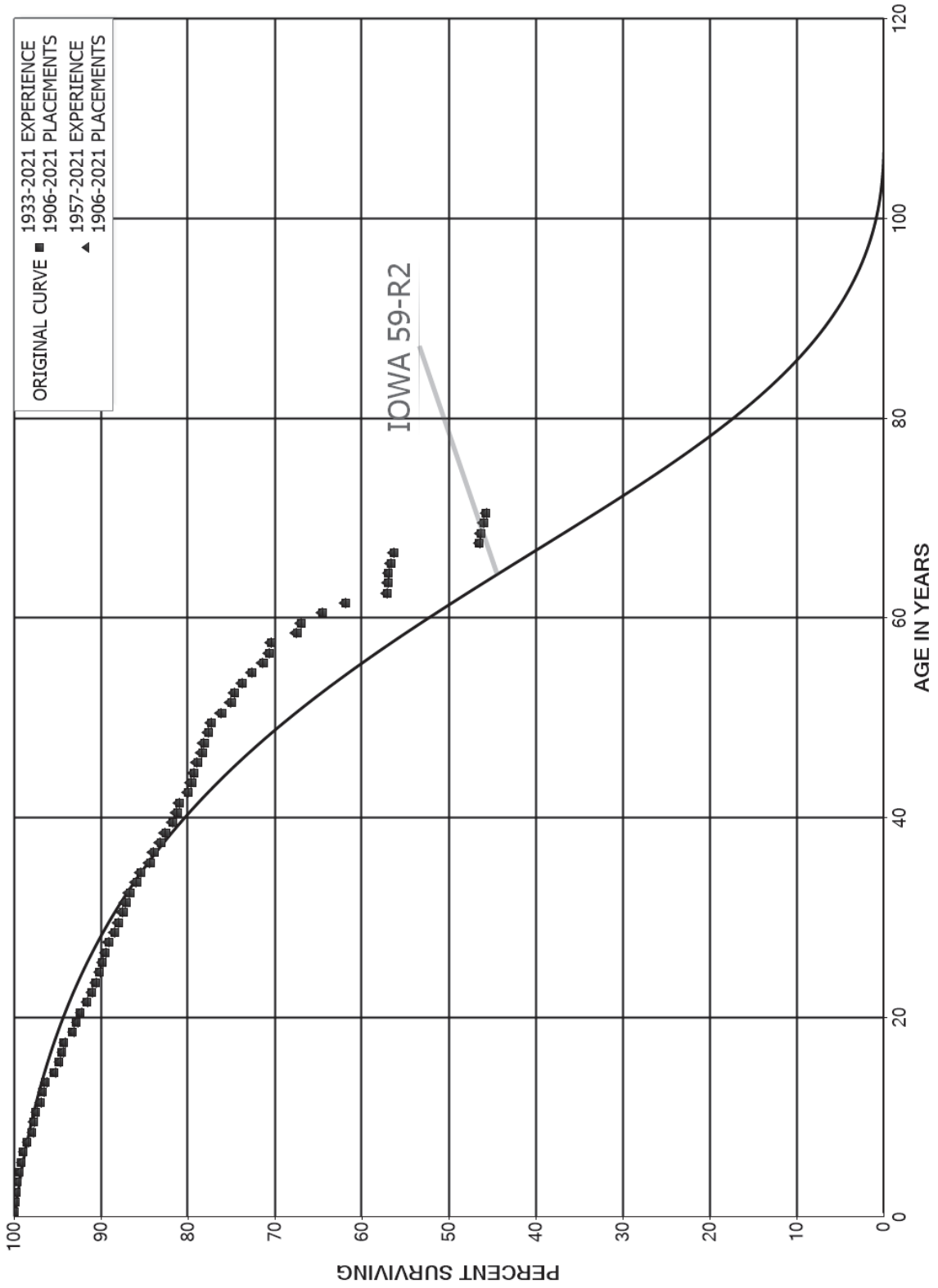
ACCOUNT 361.20 STRUCTURES AND IMPROVEMENTS - CLEARING

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1956-2021 EXPERIENCE BAND 2005-2021

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					
40.5					
41.5					
42.5					
43.5					
44.5					
45.5					
46.5					
47.5					
48.5					
49.5					
50.5					
51.5					
52.5					
53.5					
54.5					
55.5					
56.5					
57.5					
58.5					
59.5	16,369		0.0000		
60.5	16,369		0.0000		
61.5	16,369		0.0000		
62.5	16,369		0.0000		
63.5	16,369		0.0000		
64.5	16,369		0.0000		
65.5					

JERSEY CENTRAL POWER & LIGHT COMPANY
ACCOUNT 362.00 STATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 362.00 STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1906-2021 EXPERIENCE BAND 1933-2021

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	611,371,001	388,867	0.0006	0.9994	100.00
0.5	575,369,317	803,543	0.0014	0.9986	99.94
1.5	552,950,151	483,424	0.0009	0.9991	99.80
2.5	535,979,552	724,354	0.0014	0.9986	99.71
3.5	529,244,987	984,487	0.0019	0.9981	99.57
4.5	516,668,191	1,304,209	0.0025	0.9975	99.39
5.5	497,495,099	1,180,408	0.0024	0.9976	99.14
6.5	480,912,348	2,150,216	0.0045	0.9955	98.90
7.5	470,271,999	2,335,847	0.0050	0.9950	98.46
8.5	454,268,183	898,803	0.0020	0.9980	97.97
9.5	438,762,059	1,309,831	0.0030	0.9970	97.78
10.5	419,845,078	2,067,613	0.0049	0.9951	97.49
11.5	412,690,920	1,334,947	0.0032	0.9968	97.01
12.5	401,571,748	1,217,831	0.0030	0.9970	96.69
13.5	381,640,646	4,191,618	0.0110	0.9890	96.40
14.5	356,943,567	2,008,580	0.0056	0.9944	95.34
15.5	342,841,930	1,079,809	0.0031	0.9969	94.80
16.5	319,582,779	714,990	0.0022	0.9978	94.51
17.5	309,772,804	3,487,367	0.0113	0.9887	94.29
18.5	300,908,184	1,277,270	0.0042	0.9958	93.23
19.5	282,202,572	1,456,982	0.0052	0.9948	92.84
20.5	262,753,638	1,984,319	0.0076	0.9924	92.36
21.5	244,149,535	1,547,159	0.0063	0.9937	91.66
22.5	239,852,947	1,179,700	0.0049	0.9951	91.08
23.5	226,714,522	1,160,241	0.0051	0.9949	90.63
24.5	222,060,583	879,876	0.0040	0.9960	90.17
25.5	207,926,456	721,735	0.0035	0.9965	89.81
26.5	197,746,165	900,013	0.0046	0.9954	89.50
27.5	192,884,143	1,597,088	0.0083	0.9917	89.09
28.5	170,859,530	815,529	0.0048	0.9952	88.35
29.5	147,063,309	884,461	0.0060	0.9940	87.93
30.5	136,865,576	510,430	0.0037	0.9963	87.40
31.5	132,184,875	701,149	0.0053	0.9947	87.08
32.5	123,814,771	1,129,856	0.0091	0.9909	86.61
33.5	110,376,423	621,398	0.0056	0.9944	85.82
34.5	102,429,194	1,252,718	0.0122	0.9878	85.34
35.5	97,519,751	497,886	0.0051	0.9949	84.30
36.5	92,361,794	886,795	0.0096	0.9904	83.87
37.5	90,543,314	588,829	0.0065	0.9935	83.06
38.5	89,457,833	881,251	0.0099	0.9901	82.52

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 362.00 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1906-2021 EXPERIENCE BAND 1933-2021

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	83,230,501	491,066	0.0059	0.9941	81.71
40.5	82,622,011	336,066	0.0041	0.9959	81.23
41.5	80,190,822	954,008	0.0119	0.9881	80.90
42.5	74,115,502	403,412	0.0054	0.9946	79.93
43.5	72,914,544	236,805	0.0032	0.9968	79.50
44.5	72,049,290	367,091	0.0051	0.9949	79.24
45.5	71,504,347	470,557	0.0066	0.9934	78.84
46.5	67,240,029	224,429	0.0033	0.9967	78.32
47.5	64,448,524	387,376	0.0060	0.9940	78.06
48.5	58,149,869	249,691	0.0043	0.9957	77.59
49.5	52,249,189	797,960	0.0153	0.9847	77.25
50.5	46,122,622	675,743	0.0147	0.9853	76.07
51.5	39,218,983	209,039	0.0053	0.9947	74.96
52.5	32,850,831	376,193	0.0115	0.9885	74.56
53.5	28,003,840	431,178	0.0154	0.9846	73.71
54.5	23,140,746	398,055	0.0172	0.9828	72.57
55.5	20,093,658	200,840	0.0100	0.9900	71.32
56.5	18,534,173	68,532	0.0037	0.9963	70.61
57.5	16,629,826	690,081	0.0415	0.9585	70.35
58.5	15,059,541	102,264	0.0068	0.9932	67.43
59.5	13,760,983	512,846	0.0373	0.9627	66.97
60.5	12,342,647	495,737	0.0402	0.9598	64.48
61.5	10,770,056	841,116	0.0781	0.9219	61.89
62.5	8,736,579	9,223	0.0011	0.9989	57.05
63.5	7,108,904	12,584	0.0018	0.9982	56.99
64.5	5,861,357	30,619	0.0052	0.9948	56.89
65.5	4,849,100	28,493	0.0059	0.9941	56.60
66.5	3,904,464	679,795	0.1741	0.8259	56.26
67.5	2,682,816	7,888	0.0029	0.9971	46.47
68.5	1,944,118	14,741	0.0076	0.9924	46.33
69.5	2,280,467	12,952	0.0057	0.9943	45.98
70.5	1,740,567	14,161	0.0081	0.9919	45.72
71.5	1,384,854	9,382	0.0068	0.9932	45.35
72.5	1,071,848	41,043	0.0383	0.9617	45.04
73.5	958,822	3,826	0.0040	0.9960	43.31
74.5	842,297	4,447	0.0053	0.9947	43.14
75.5	821,179	928	0.0011	0.9989	42.91
76.5	689,497	2,091	0.0030	0.9970	42.86
77.5	679,840	94	0.0001	0.9999	42.74
78.5	652,980	3,707	0.0057	0.9943	42.73

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 362.00 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1906-2021 EXPERIENCE BAND 1933-2021

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	598,941	2	0.0000	1.0000	42.49
80.5	534,481	1,111	0.0021	0.9979	42.49
81.5	494,172	143	0.0003	0.9997	42.40
82.5	480,267	0	0.0000	1.0000	42.39
83.5	418,906	20	0.0000	1.0000	42.39
84.5	377,077	0	0.0000	1.0000	42.38
85.5	366,894	212,045	0.5779	0.4221	42.38
86.5	144,166	58	0.0004	0.9996	17.89
87.5	143,156		0.0000	1.0000	17.88
88.5	134,206		0.0000	1.0000	17.88
89.5	126,473	11,345	0.0897	0.9103	17.88
90.5	75,714		0.0000	1.0000	16.28
91.5	19,234		0.0000	1.0000	16.28
92.5	12,799		0.0000	1.0000	16.28
93.5	5,806		0.0000	1.0000	16.28
94.5					16.28

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 362.00 STATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1906-2021 EXPERIENCE BAND 1957-2021

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	603,611,288	387,263	0.0006	0.9994	100.00
0.5	568,511,024	789,756	0.0014	0.9986	99.94
1.5	547,497,858	466,189	0.0009	0.9991	99.80
2.5	531,591,414	710,598	0.0013	0.9987	99.71
3.5	525,736,123	968,871	0.0018	0.9982	99.58
4.5	513,532,019	1,289,415	0.0025	0.9975	99.40
5.5	495,078,821	1,170,542	0.0024	0.9976	99.15
6.5	478,903,725	2,135,769	0.0045	0.9955	98.91
7.5	468,501,651	2,320,886	0.0050	0.9950	98.47
8.5	452,943,047	892,234	0.0020	0.9980	97.98
9.5	437,530,192	1,301,836	0.0030	0.9970	97.79
10.5	418,521,010	2,053,318	0.0049	0.9951	97.50
11.5	411,355,370	1,315,832	0.0032	0.9968	97.02
12.5	400,188,819	1,206,673	0.0030	0.9970	96.71
13.5	380,230,802	4,179,610	0.0110	0.9890	96.42
14.5	355,553,765	2,002,243	0.0056	0.9944	95.36
15.5	341,307,561	1,065,295	0.0031	0.9969	94.82
16.5	317,929,536	688,396	0.0022	0.9978	94.53
17.5	308,220,107	3,457,516	0.0112	0.9888	94.32
18.5	299,200,010	1,240,163	0.0041	0.9959	93.26
19.5	280,368,857	1,435,745	0.0051	0.9949	92.88
20.5	260,718,662	1,955,492	0.0075	0.9925	92.40
21.5	241,934,371	1,473,750	0.0061	0.9939	91.71
22.5	237,648,028	1,121,835	0.0047	0.9953	91.15
23.5	224,582,598	1,108,190	0.0049	0.9951	90.72
24.5	220,045,884	802,350	0.0036	0.9964	90.27
25.5	206,267,122	669,506	0.0032	0.9968	89.94
26.5	196,322,849	835,624	0.0043	0.9957	89.65
27.5	191,682,505	1,509,066	0.0079	0.9921	89.27
28.5	169,867,570	707,901	0.0042	0.9958	88.57
29.5	146,328,266	855,813	0.0058	0.9942	88.20
30.5	136,403,673	489,497	0.0036	0.9964	87.68
31.5	131,916,220	686,563	0.0052	0.9948	87.37
32.5	123,626,344	1,120,963	0.0091	0.9909	86.91
33.5	110,299,607	613,966	0.0056	0.9944	86.12
34.5	102,349,908	1,246,658	0.0122	0.9878	85.64
35.5	97,455,697	495,981	0.0051	0.9949	84.60
36.5	92,297,037	886,029	0.0096	0.9904	84.17
37.5	90,477,161	588,066	0.0065	0.9935	83.36
38.5	89,395,141	881,251	0.0099	0.9901	82.82

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 362.00 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1906-2021 EXPERIENCE BAND 1957-2021

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	83,206,262	484,914	0.0058	0.9942	82.00
40.5	82,611,665	335,805	0.0041	0.9959	81.53
41.5	80,190,390	954,008	0.0119	0.9881	81.19
42.5	74,115,078	403,387	0.0054	0.9946	80.23
43.5	72,914,274	236,805	0.0032	0.9968	79.79
44.5	72,048,856	366,826	0.0051	0.9949	79.53
45.5	71,504,300	470,557	0.0066	0.9934	79.13
46.5	67,239,983	224,429	0.0033	0.9967	78.61
47.5	64,448,477	387,376	0.0060	0.9940	78.34
48.5	58,149,822	249,691	0.0043	0.9957	77.87
49.5	52,249,142	797,960	0.0153	0.9847	77.54
50.5	46,122,622	675,743	0.0147	0.9853	76.36
51.5	39,218,983	209,039	0.0053	0.9947	75.24
52.5	32,850,831	376,193	0.0115	0.9885	74.84
53.5	28,003,840	431,178	0.0154	0.9846	73.98
54.5	23,140,746	398,055	0.0172	0.9828	72.84
55.5	20,093,658	200,840	0.0100	0.9900	71.59
56.5	18,534,173	68,532	0.0037	0.9963	70.87
57.5	16,629,826	690,081	0.0415	0.9585	70.61
58.5	15,059,541	102,264	0.0068	0.9932	67.68
59.5	13,760,983	512,846	0.0373	0.9627	67.22
60.5	12,342,647	495,737	0.0402	0.9598	64.71
61.5	10,770,056	841,116	0.0781	0.9219	62.11
62.5	8,736,579	9,223	0.0011	0.9989	57.26
63.5	7,108,904	12,584	0.0018	0.9982	57.20
64.5	5,861,357	30,619	0.0052	0.9948	57.10
65.5	4,849,100	28,493	0.0059	0.9941	56.80
66.5	3,904,464	679,795	0.1741	0.8259	56.47
67.5	2,682,816	7,888	0.0029	0.9971	46.64
68.5	1,944,118	14,741	0.0076	0.9924	46.50
69.5	2,280,467	12,952	0.0057	0.9943	46.15
70.5	1,740,567	14,161	0.0081	0.9919	45.89
71.5	1,384,854	9,382	0.0068	0.9932	45.51
72.5	1,071,848	41,043	0.0383	0.9617	45.20
73.5	958,822	3,826	0.0040	0.9960	43.47
74.5	842,297	4,447	0.0053	0.9947	43.30
75.5	821,179	928	0.0011	0.9989	43.07
76.5	689,497	2,091	0.0030	0.9970	43.02
77.5	679,840	94	0.0001	0.9999	42.89
78.5	652,980	3,707	0.0057	0.9943	42.89

JERSEY CENTRAL POWER & LIGHT COMPANY

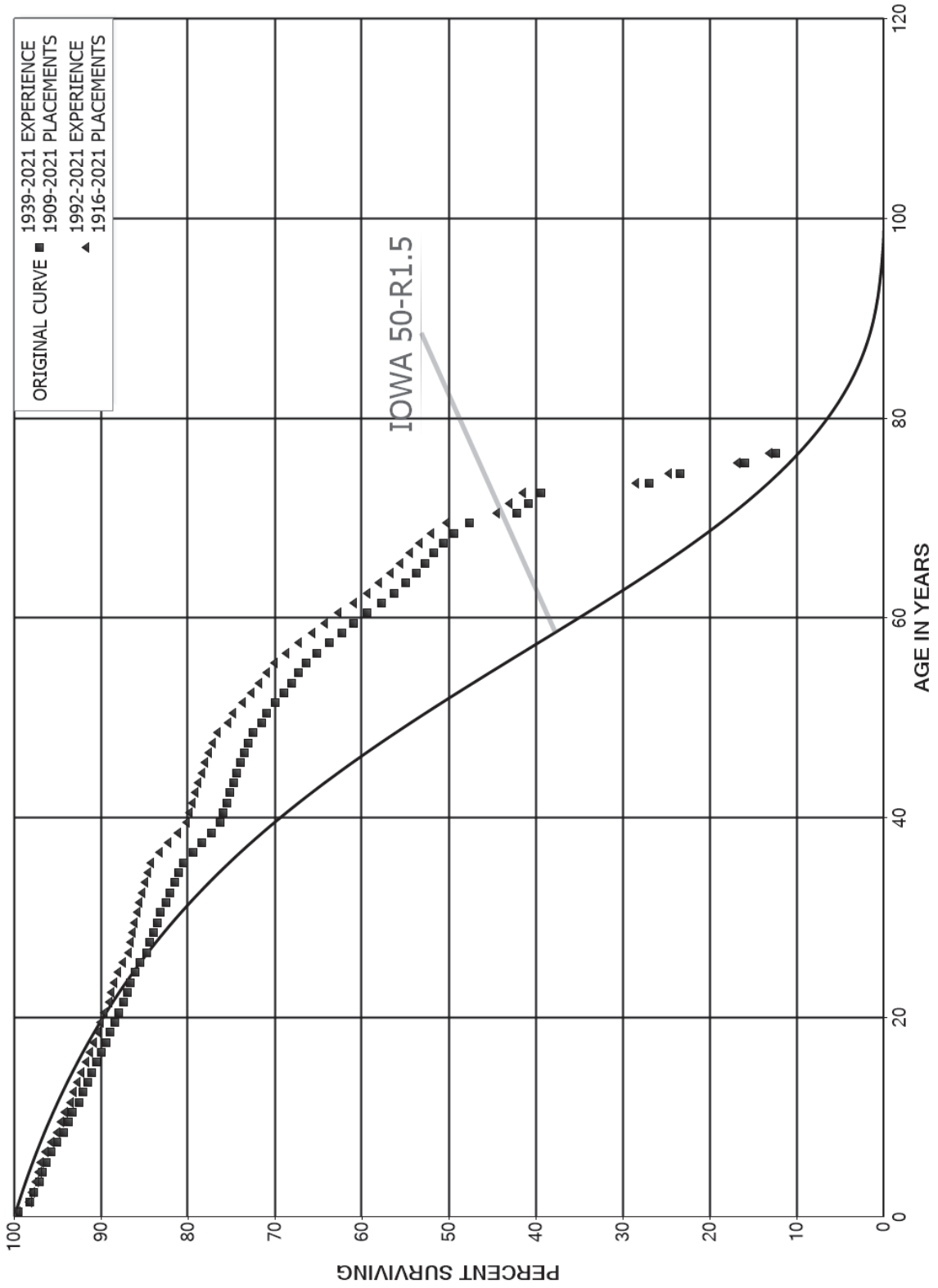
ACCOUNT 362.00 STATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1906-2021 EXPERIENCE BAND 1957-2021

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	598,941	2	0.0000	1.0000	42.64
80.5	534,481	1,111	0.0021	0.9979	42.64
81.5	494,172	143	0.0003	0.9997	42.55
82.5	480,267	0	0.0000	1.0000	42.54
83.5	418,906	20	0.0000	1.0000	42.54
84.5	377,077	0	0.0000	1.0000	42.54
85.5	366,894	212,045	0.5779	0.4221	42.54
86.5	144,166	58	0.0004	0.9996	17.95
87.5	143,156		0.0000	1.0000	17.95
88.5	134,206		0.0000	1.0000	17.95
89.5	126,473	11,345	0.0897	0.9103	17.95
90.5	75,714		0.0000	1.0000	16.34
91.5	19,234		0.0000	1.0000	16.34
92.5	12,799		0.0000	1.0000	16.34
93.5	5,806		0.0000	1.0000	16.34
94.5					16.34

JERSEY CENTRAL POWER & LIGHT COMPANY
ACCOUNT 364.00 POLES, TOWERS AND FIXTURES
ORIGINAL AND SMOOTH SURVIVOR CURVES



JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1909-2021 EXPERIENCE BAND 1939-2021

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	893,208,214	4,331,587	0.0048	0.9952	100.00
0.5	852,211,912	11,944,370	0.0140	0.9860	99.52
1.5	808,941,117	3,487,514	0.0043	0.9957	98.12
2.5	778,005,883	4,645,173	0.0060	0.9940	97.70
3.5	707,089,500	3,146,840	0.0045	0.9955	97.11
4.5	701,286,905	2,940,544	0.0042	0.9958	96.68
5.5	688,923,315	4,162,424	0.0060	0.9940	96.28
6.5	675,634,537	4,772,874	0.0071	0.9929	95.69
7.5	654,979,805	5,108,233	0.0078	0.9922	95.02
8.5	638,187,105	3,612,247	0.0057	0.9943	94.28
9.5	514,402,240	2,715,443	0.0053	0.9947	93.74
10.5	497,465,333	3,770,569	0.0076	0.9924	93.25
11.5	476,311,000	2,601,468	0.0055	0.9945	92.54
12.5	458,816,237	2,492,471	0.0054	0.9946	92.04
13.5	438,745,176	2,235,443	0.0051	0.9949	91.54
14.5	428,667,437	2,838,309	0.0066	0.9934	91.07
15.5	406,323,389	2,464,647	0.0061	0.9939	90.47
16.5	389,039,856	2,082,437	0.0054	0.9946	89.92
17.5	369,128,379	2,127,436	0.0058	0.9942	89.44
18.5	357,195,934	1,965,812	0.0055	0.9945	88.92
19.5	344,427,179	1,810,520	0.0053	0.9947	88.43
20.5	322,852,578	2,138,169	0.0066	0.9934	87.97
21.5	307,937,777	1,418,890	0.0046	0.9954	87.39
22.5	295,789,462	1,435,796	0.0049	0.9951	86.98
23.5	265,821,597	1,473,141	0.0055	0.9945	86.56
24.5	245,460,213	1,758,494	0.0072	0.9928	86.08
25.5	228,016,898	1,907,449	0.0084	0.9916	85.46
26.5	212,423,873	965,391	0.0045	0.9955	84.75
27.5	199,482,473	936,728	0.0047	0.9953	84.36
28.5	187,024,522	945,618	0.0051	0.9949	83.97
29.5	175,408,242	845,461	0.0048	0.9952	83.54
30.5	162,110,449	1,217,683	0.0075	0.9925	83.14
31.5	151,030,804	847,479	0.0056	0.9944	82.52
32.5	141,319,749	916,127	0.0065	0.9935	82.05
33.5	129,939,039	808,384	0.0062	0.9938	81.52
34.5	121,399,563	702,068	0.0058	0.9942	81.01
35.5	113,080,450	1,578,155	0.0140	0.9860	80.55
36.5	105,335,348	1,384,989	0.0131	0.9869	79.42
37.5	100,149,643	1,326,037	0.0132	0.9868	78.38
38.5	95,458,941	1,312,316	0.0137	0.9863	77.34

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1909-2021 EXPERIENCE BAND 1939-2021

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	91,203,908	420,182	0.0046	0.9954	76.28
40.5	86,546,509	423,505	0.0049	0.9951	75.92
41.5	81,644,729	453,464	0.0056	0.9944	75.55
42.5	76,657,939	385,628	0.0050	0.9950	75.13
43.5	72,912,905	379,005	0.0052	0.9948	74.76
44.5	69,621,135	362,991	0.0052	0.9948	74.37
45.5	66,149,369	408,635	0.0062	0.9938	73.98
46.5	63,131,855	367,814	0.0058	0.9942	73.52
47.5	58,213,672	435,537	0.0075	0.9925	73.09
48.5	53,606,068	796,491	0.0149	0.9851	72.55
49.5	48,884,642	344,007	0.0070	0.9930	71.47
50.5	45,186,500	620,650	0.0137	0.9863	70.97
51.5	41,898,898	592,362	0.0141	0.9859	69.99
52.5	37,480,707	494,561	0.0132	0.9868	69.00
53.5	33,354,919	404,803	0.0121	0.9879	68.09
54.5	29,292,929	360,836	0.0123	0.9877	67.26
55.5	25,655,434	487,911	0.0190	0.9810	66.44
56.5	22,631,214	498,291	0.0220	0.9780	65.17
57.5	19,495,647	455,978	0.0234	0.9766	63.74
58.5	16,631,927	341,956	0.0206	0.9794	62.25
59.5	14,613,622	373,145	0.0255	0.9745	60.97
60.5	13,013,321	371,716	0.0286	0.9714	59.41
61.5	11,522,013	284,950	0.0247	0.9753	57.71
62.5	10,195,983	233,532	0.0229	0.9771	56.29
63.5	8,931,777	198,728	0.0222	0.9778	55.00
64.5	7,707,788	148,466	0.0193	0.9807	53.77
65.5	6,980,484	138,227	0.0198	0.9802	52.74
66.5	6,013,939	130,907	0.0218	0.9782	51.69
67.5	5,337,837	126,974	0.0238	0.9762	50.57
68.5	4,701,500	161,454	0.0343	0.9657	49.37
69.5	4,346,518	503,751	0.1159	0.8841	47.67
70.5	3,558,941	114,194	0.0321	0.9679	42.15
71.5	3,389,206	119,824	0.0354	0.9646	40.79
72.5	2,924,521	919,239	0.3143	0.6857	39.35
73.5	561,961	74,280	0.1322	0.8678	26.98
74.5	336,586	107,915	0.3206	0.6794	23.42
75.5	155,597	34,581	0.2222	0.7778	15.91
76.5	74,257	32,691	0.4402	0.5598	12.37
77.5	13,275	60	0.0046	0.9954	6.93
78.5	1,269	474	0.3733	0.6267	6.89

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1909-2021 EXPERIENCE BAND 1939-2021

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	795		0.0000	1.0000	4.32
80.5	795		0.0000	1.0000	4.32
81.5	795	130	0.1635	0.8365	4.32
82.5	665	665	1.0000		3.61
83.5					

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1916-2021 EXPERIENCE BAND 1992-2021

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	644,490,443	2,930,122	0.0045	0.9955	100.00
0.5	635,254,945	9,030,239	0.0142	0.9858	99.55
1.5	606,905,095	1,634,212	0.0027	0.9973	98.13
2.5	589,120,585	3,041,536	0.0052	0.9948	97.87
3.5	550,014,549	1,716,344	0.0031	0.9969	97.36
4.5	554,958,241	1,525,114	0.0027	0.9973	97.06
5.5	553,505,870	2,886,691	0.0052	0.9948	96.79
6.5	549,953,920	3,554,732	0.0065	0.9935	96.29
7.5	536,184,958	3,942,525	0.0074	0.9926	95.66
8.5	525,377,088	2,507,850	0.0048	0.9952	94.96
9.5	406,952,624	1,701,494	0.0042	0.9958	94.51
10.5	396,287,195	2,818,940	0.0071	0.9929	94.11
11.5	381,936,818	1,721,434	0.0045	0.9955	93.44
12.5	370,634,272	1,686,402	0.0046	0.9954	93.02
13.5	355,271,528	1,453,308	0.0041	0.9959	92.60
14.5	348,942,097	2,082,838	0.0060	0.9940	92.22
15.5	330,766,129	1,774,777	0.0054	0.9946	91.67
16.5	317,758,203	1,393,944	0.0044	0.9956	91.18
17.5	303,256,344	1,519,981	0.0050	0.9950	90.78
18.5	296,471,638	1,347,348	0.0045	0.9955	90.32
19.5	288,275,522	1,257,452	0.0044	0.9956	89.91
20.5	270,177,928	1,621,104	0.0060	0.9940	89.52
21.5	258,029,624	860,613	0.0033	0.9967	88.98
22.5	249,703,374	945,415	0.0038	0.9962	88.68
23.5	223,424,773	1,006,798	0.0045	0.9955	88.35
24.5	206,743,336	1,265,872	0.0061	0.9939	87.95
25.5	192,781,340	1,405,008	0.0073	0.9927	87.41
26.5	180,750,523	467,841	0.0026	0.9974	86.78
27.5	170,929,333	489,631	0.0029	0.9971	86.55
28.5	161,324,439	515,631	0.0032	0.9968	86.30
29.5	152,617,003	454,010	0.0030	0.9970	86.03
30.5	141,627,057	525,427	0.0037	0.9963	85.77
31.5	132,975,970	444,626	0.0033	0.9967	85.45
32.5	125,174,163	496,261	0.0040	0.9960	85.17
33.5	115,712,305	470,969	0.0041	0.9959	84.83
34.5	108,846,003	381,493	0.0035	0.9965	84.48
35.5	101,666,725	1,228,607	0.0121	0.9879	84.19
36.5	95,395,070	1,173,926	0.0123	0.9877	83.17
37.5	91,270,371	1,165,203	0.0128	0.9872	82.15
38.5	87,491,227	1,160,388	0.0133	0.9867	81.10

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1916-2021 EXPERIENCE BAND 1992-2021

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	83,901,132	290,977	0.0035	0.9965	80.02
40.5	79,883,139	332,411	0.0042	0.9958	79.75
41.5	75,475,601	362,160	0.0048	0.9952	79.41
42.5	71,148,884	314,460	0.0044	0.9956	79.03
43.5	67,869,809	319,274	0.0047	0.9953	78.68
44.5	64,939,081	316,021	0.0049	0.9951	78.31
45.5	61,743,654	369,811	0.0060	0.9940	77.93
46.5	58,876,867	332,166	0.0056	0.9944	77.47
47.5	54,070,542	404,145	0.0075	0.9925	77.03
48.5	49,566,474	766,525	0.0155	0.9845	76.45
49.5	44,965,186	313,418	0.0070	0.9930	75.27
50.5	41,450,316	597,214	0.0144	0.9856	74.75
51.5	40,772,068	568,350	0.0139	0.9861	73.67
52.5	36,524,232	479,118	0.0131	0.9869	72.64
53.5	32,517,552	389,522	0.0120	0.9880	71.69
54.5	28,584,485	348,395	0.0122	0.9878	70.83
55.5	25,041,122	474,471	0.0189	0.9811	69.97
56.5	22,082,063	486,196	0.0220	0.9780	68.64
57.5	19,022,538	441,943	0.0232	0.9768	67.13
58.5	16,232,982	331,886	0.0204	0.9796	65.57
59.5	14,293,646	366,293	0.0256	0.9744	64.23
60.5	12,773,043	365,164	0.0286	0.9714	62.58
61.5	11,391,129	282,913	0.0248	0.9752	60.79
62.5	10,167,976	233,149	0.0229	0.9771	59.28
63.5	8,916,074	198,647	0.0223	0.9777	57.92
64.5	7,696,728	148,306	0.0193	0.9807	56.63
65.5	6,972,913	138,087	0.0198	0.9802	55.54
66.5	6,007,354	130,907	0.0218	0.9782	54.44
67.5	5,331,471	126,974	0.0238	0.9762	53.26
68.5	4,696,288	161,454	0.0344	0.9656	51.99
69.5	4,345,146	503,751	0.1159	0.8841	50.20
70.5	3,557,672	114,194	0.0321	0.9679	44.38
71.5	3,388,411	119,824	0.0354	0.9646	42.96
72.5	2,923,726	919,239	0.3144	0.6856	41.44
73.5	561,166	74,280	0.1324	0.8676	28.41
74.5	335,921	107,915	0.3213	0.6787	24.65
75.5	155,597	34,581	0.2222	0.7778	16.73
76.5	74,257	32,691	0.4402	0.5598	13.01
77.5	13,275	60	0.0046	0.9954	7.28
78.5	1,269	474	0.3733	0.6267	7.25

JERSEY CENTRAL POWER & LIGHT COMPANY

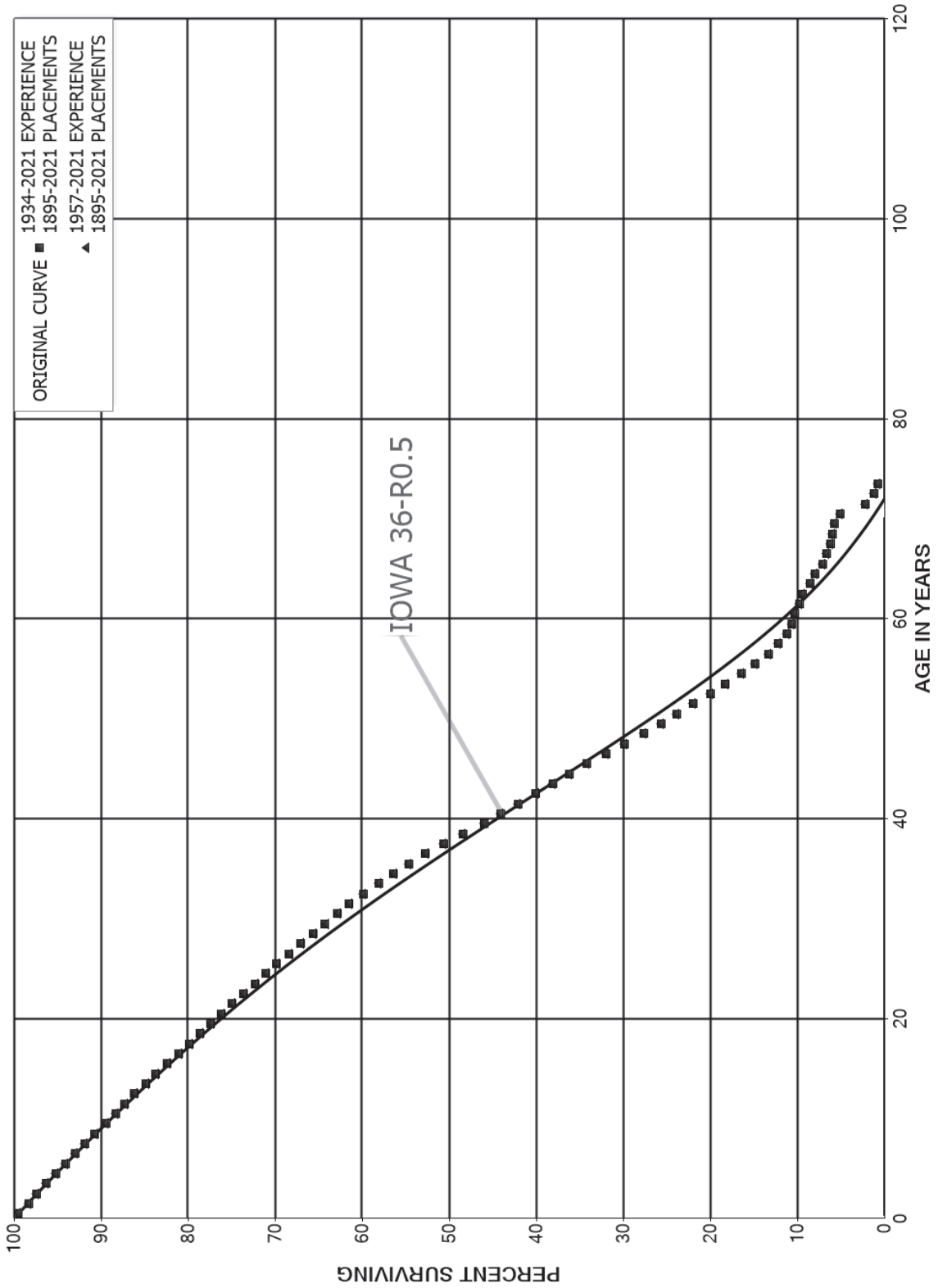
ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1916-2021 EXPERIENCE BAND 1992-2021

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	795		0.0000	1.0000	4.54
80.5	795		0.0000	1.0000	4.54
81.5	795	130	0.1635	0.8365	4.54
82.5	665	665	1.0000		3.80
83.5					

JERSEY CENTRAL POWER & LIGHT COMPANY
ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1895-2021 EXPERIENCE BAND 1934-2021

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	1,339,370,632	6,913,707	0.0052	0.9948	100.00
0.5	1,298,444,701	15,414,318	0.0119	0.9881	99.48
1.5	1,206,286,455	11,597,488	0.0096	0.9904	98.30
2.5	1,123,403,908	12,614,830	0.0112	0.9888	97.36
3.5	1,025,772,239	11,163,761	0.0109	0.9891	96.26
4.5	999,211,014	11,655,913	0.0117	0.9883	95.22
5.5	958,108,082	11,458,552	0.0120	0.9880	94.11
6.5	918,594,335	11,256,999	0.0123	0.9877	92.98
7.5	870,204,709	10,757,464	0.0124	0.9876	91.84
8.5	835,629,057	12,041,712	0.0144	0.9856	90.71
9.5	639,881,274	7,629,268	0.0119	0.9881	89.40
10.5	609,779,225	7,410,274	0.0122	0.9878	88.33
11.5	576,941,863	7,362,231	0.0128	0.9872	87.26
12.5	543,360,650	8,506,463	0.0157	0.9843	86.15
13.5	512,484,360	6,581,773	0.0128	0.9872	84.80
14.5	489,406,372	7,846,993	0.0160	0.9840	83.71
15.5	453,440,757	7,043,511	0.0155	0.9845	82.37
16.5	430,375,402	6,376,288	0.0148	0.9852	81.09
17.5	407,508,189	6,405,302	0.0157	0.9843	79.89
18.5	387,671,792	6,117,664	0.0158	0.9842	78.63
19.5	370,909,979	5,861,052	0.0158	0.9842	77.39
20.5	348,517,430	5,646,077	0.0162	0.9838	76.17
21.5	330,089,795	5,758,684	0.0174	0.9826	74.93
22.5	311,832,353	5,477,249	0.0176	0.9824	73.62
23.5	277,143,145	4,696,743	0.0169	0.9831	72.33
24.5	261,575,046	4,722,667	0.0181	0.9819	71.11
25.5	248,615,264	5,033,517	0.0202	0.9798	69.82
26.5	233,240,724	4,614,949	0.0198	0.9802	68.41
27.5	218,706,719	4,817,292	0.0220	0.9780	67.05
28.5	204,475,772	4,191,540	0.0205	0.9795	65.58
29.5	190,363,563	4,074,989	0.0214	0.9786	64.23
30.5	174,549,602	3,769,196	0.0216	0.9784	62.86
31.5	163,504,360	4,323,814	0.0264	0.9736	61.50
32.5	151,816,624	4,533,075	0.0299	0.9701	59.87
33.5	139,933,670	4,186,234	0.0299	0.9701	58.09
34.5	131,334,640	4,023,090	0.0306	0.9694	56.35
35.5	123,119,627	4,369,983	0.0355	0.9645	54.62
36.5	116,077,257	4,485,912	0.0386	0.9614	52.68
37.5	110,014,069	4,867,989	0.0442	0.9558	50.65
38.5	103,421,409	5,129,824	0.0496	0.9504	48.41

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1895-2021 EXPERIENCE BAND 1934-2021

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	96,845,216	4,130,198	0.0426	0.9574	46.01
40.5	90,581,882	4,069,349	0.0449	0.9551	44.04
41.5	83,649,262	4,082,272	0.0488	0.9512	42.07
42.5	76,982,258	3,653,922	0.0475	0.9525	40.01
43.5	71,451,591	3,624,368	0.0507	0.9493	38.11
44.5	66,545,876	3,750,775	0.0564	0.9436	36.18
45.5	61,268,341	3,934,719	0.0642	0.9358	34.14
46.5	55,854,605	3,743,447	0.0670	0.9330	31.95
47.5	50,333,659	3,667,100	0.0729	0.9271	29.81
48.5	45,013,826	3,234,611	0.0719	0.9281	27.64
49.5	40,036,444	2,898,627	0.0724	0.9276	25.65
50.5	35,672,362	2,791,752	0.0783	0.9217	23.79
51.5	31,630,565	2,772,679	0.0877	0.9123	21.93
52.5	27,379,896	2,431,969	0.0888	0.9112	20.01
53.5	23,374,551	2,308,368	0.0988	0.9012	18.23
54.5	19,505,763	1,841,764	0.0944	0.9056	16.43
55.5	16,281,960	1,741,138	0.1069	0.8931	14.88
56.5	15,141,207	1,322,892	0.0874	0.9126	13.29
57.5	13,042,365	991,627	0.0760	0.9240	12.13
58.5	11,572,047	595,045	0.0514	0.9486	11.21
59.5	10,492,717	326,007	0.0311	0.9689	10.63
60.5	9,791,619	539,279	0.0551	0.9449	10.30
61.5	8,938,061	312,697	0.0350	0.9650	9.73
62.5	8,392,452	750,192	0.0894	0.9106	9.39
63.5	7,449,495	565,080	0.0759	0.9241	8.55
64.5	6,669,996	742,853	0.1114	0.8886	7.90
65.5	5,801,767	357,160	0.0616	0.9384	7.02
66.5	5,341,415	292,293	0.0547	0.9453	6.59
67.5	5,049,055	198,039	0.0392	0.9608	6.23
68.5	4,850,865	171,256	0.0353	0.9647	5.99
69.5	4,679,482	550,392	0.1176	0.8824	5.77
70.5	4,128,985	2,361,263	0.5719	0.4281	5.09
71.5	1,767,687	841,386	0.4760	0.5240	2.18
72.5	926,290	323,092	0.3488	0.6512	1.14
73.5	68,328	20,621	0.3018	0.6982	0.74
74.5	47,687	20,451	0.4289	0.5711	0.52
75.5	27,235	21,030	0.7722	0.2278	0.30
76.5	6,205	1,116	0.1799	0.8201	0.07
77.5	5,086	490	0.0964	0.9036	0.06
78.5	4,595	2,261	0.4920	0.5080	0.05

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1895-2021 EXPERIENCE BAND 1934-2021

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	2,334	464	0.1987	0.8013	0.03
80.5	1,870	28	0.0148	0.9852	0.02
81.5	1,843	26	0.0140	0.9860	0.02
82.5	1,817	13	0.0071	0.9929	0.02
83.5	1,804	253	0.1401	0.8599	0.02
84.5	1,551		0.0000	1.0000	0.02
85.5	1,551		0.0000	1.0000	0.02
86.5	1,551		0.0000	1.0000	0.02
87.5	1,551		0.0000	1.0000	0.02
88.5	1,551		0.0000	1.0000	0.02
89.5	1,551		0.0000	1.0000	0.02
90.5	1,551		0.0000	1.0000	0.02
91.5	1,551		0.0000	1.0000	0.02
92.5	1,551	0	0.0003	0.9997	0.02
93.5	1,551	0	0.0001	0.9999	0.02
94.5	1,550	0	0.0001	0.9999	0.02
95.5	1,550	2	0.0013	0.9987	0.02
96.5	1,548		0.0000	1.0000	0.02
97.5	2,020		0.0000	1.0000	0.02
98.5	2,020		0.0000	1.0000	0.02
99.5	2,020		0.0000	1.0000	0.02
100.5	2,020		0.0000	1.0000	0.02
101.5	2,020		0.0000	1.0000	0.02
102.5	2,020		0.0000	1.0000	0.02
103.5	2,020	542	0.2684	0.7316	0.02
104.5	1,477	87	0.0587	0.9413	0.01
105.5	1,383	306	0.2215	0.7785	0.01
106.5	1,077		0.0000	1.0000	0.01
107.5	1,077		0.0000	1.0000	0.01
108.5	1,077		0.0000	1.0000	0.01
109.5	1,077		0.0000	1.0000	0.01
110.5	1,077		0.0000	1.0000	0.01
111.5	1,077		0.0000	1.0000	0.01
112.5	1,077	1,077	1.0000		0.01
113.5					

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1895-2021 EXPERIENCE BAND 1957-2021

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	1,328,300,673	6,896,148	0.0052	0.9948	100.00
0.5	1,288,540,111	15,368,413	0.0119	0.9881	99.48
1.5	1,197,691,643	11,560,427	0.0097	0.9903	98.29
2.5	1,115,782,635	12,576,821	0.0113	0.9887	97.35
3.5	1,018,594,804	11,132,925	0.0109	0.9891	96.25
4.5	992,386,867	11,618,717	0.0117	0.9883	95.20
5.5	951,817,326	11,425,178	0.0120	0.9880	94.08
6.5	912,762,909	11,230,695	0.0123	0.9877	92.95
7.5	864,801,341	10,733,645	0.0124	0.9876	91.81
8.5	830,674,683	12,027,343	0.0145	0.9855	90.67
9.5	635,223,318	7,620,641	0.0120	0.9880	89.36
10.5	605,132,375	7,403,204	0.0122	0.9878	88.28
11.5	572,250,703	7,356,109	0.0129	0.9871	87.20
12.5	538,551,747	8,500,094	0.0158	0.9842	86.08
13.5	507,474,221	6,572,777	0.0130	0.9870	84.72
14.5	484,220,282	7,837,608	0.0162	0.9838	83.63
15.5	448,316,268	7,040,185	0.0157	0.9843	82.27
16.5	429,253,620	6,374,977	0.0149	0.9851	80.98
17.5	406,354,570	6,404,926	0.0158	0.9842	79.78
18.5	386,520,086	6,116,437	0.0158	0.9842	78.52
19.5	369,809,287	5,860,359	0.0158	0.9842	77.28
20.5	347,243,685	5,645,975	0.0163	0.9837	76.05
21.5	328,770,439	5,757,917	0.0175	0.9825	74.82
22.5	310,464,054	5,475,716	0.0176	0.9824	73.51
23.5	275,746,442	4,694,671	0.0170	0.9830	72.21
24.5	260,189,039	4,713,609	0.0181	0.9819	70.98
25.5	247,420,344	5,032,981	0.0203	0.9797	69.70
26.5	232,314,622	4,603,959	0.0198	0.9802	68.28
27.5	217,973,165	4,794,052	0.0220	0.9780	66.92
28.5	203,871,927	4,172,799	0.0205	0.9795	65.45
29.5	189,901,335	4,074,900	0.0215	0.9785	64.11
30.5	174,198,355	3,764,523	0.0216	0.9784	62.74
31.5	163,203,061	4,216,358	0.0258	0.9742	61.38
32.5	151,685,623	4,439,890	0.0293	0.9707	59.80
33.5	139,897,666	4,161,159	0.0297	0.9703	58.05
34.5	131,311,738	4,005,834	0.0305	0.9695	56.32
35.5	123,109,950	4,364,736	0.0355	0.9645	54.60
36.5	116,076,070	4,485,831	0.0386	0.9614	52.67
37.5	110,012,992	4,867,989	0.0442	0.9558	50.63
38.5	103,419,861	5,129,824	0.0496	0.9504	48.39

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1895-2021 EXPERIENCE BAND 1957-2021

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	96,843,657	4,130,186	0.0426	0.9574	45.99
40.5	90,580,334	4,069,349	0.0449	0.9551	44.03
41.5	83,647,714	4,082,272	0.0488	0.9512	42.05
42.5	76,980,710	3,653,922	0.0475	0.9525	40.00
43.5	71,450,043	3,624,368	0.0507	0.9493	38.10
44.5	66,544,328	3,750,775	0.0564	0.9436	36.17
45.5	61,266,793	3,934,719	0.0642	0.9358	34.13
46.5	55,853,056	3,743,447	0.0670	0.9330	31.94
47.5	50,332,111	3,667,100	0.0729	0.9271	29.80
48.5	45,012,277	3,234,611	0.0719	0.9281	27.63
49.5	40,034,896	2,898,627	0.0724	0.9276	25.64
50.5	35,670,813	2,791,752	0.0783	0.9217	23.78
51.5	31,629,016	2,772,679	0.0877	0.9123	21.92
52.5	27,378,348	2,431,969	0.0888	0.9112	20.00
53.5	23,373,003	2,308,368	0.0988	0.9012	18.22
54.5	19,504,215	1,841,764	0.0944	0.9056	16.42
55.5	16,280,411	1,741,138	0.1069	0.8931	14.87
56.5	15,140,736	1,322,892	0.0874	0.9126	13.28
57.5	13,041,893	991,627	0.0760	0.9240	12.12
58.5	11,571,576	595,045	0.0514	0.9486	11.20
59.5	10,492,246	326,007	0.0311	0.9689	10.62
60.5	9,791,147	539,279	0.0551	0.9449	10.29
61.5	8,938,061	312,697	0.0350	0.9650	9.73
62.5	8,392,452	750,192	0.0894	0.9106	9.39
63.5	7,449,495	565,080	0.0759	0.9241	8.55
64.5	6,669,996	742,853	0.1114	0.8886	7.90
65.5	5,801,767	357,160	0.0616	0.9384	7.02
66.5	5,341,415	292,293	0.0547	0.9453	6.59
67.5	5,049,055	198,039	0.0392	0.9608	6.23
68.5	4,850,865	171,256	0.0353	0.9647	5.98
69.5	4,679,482	550,392	0.1176	0.8824	5.77
70.5	4,128,985	2,361,263	0.5719	0.4281	5.09
71.5	1,767,687	841,386	0.4760	0.5240	2.18
72.5	926,290	323,092	0.3488	0.6512	1.14
73.5	68,328	20,621	0.3018	0.6982	0.74
74.5	47,687	20,451	0.4289	0.5711	0.52
75.5	27,235	21,030	0.7722	0.2278	0.30
76.5	6,205	1,116	0.1799	0.8201	0.07
77.5	5,086	490	0.0964	0.9036	0.06
78.5	4,595	2,261	0.4920	0.5080	0.05

JERSEY CENTRAL POWER & LIGHT COMPANY

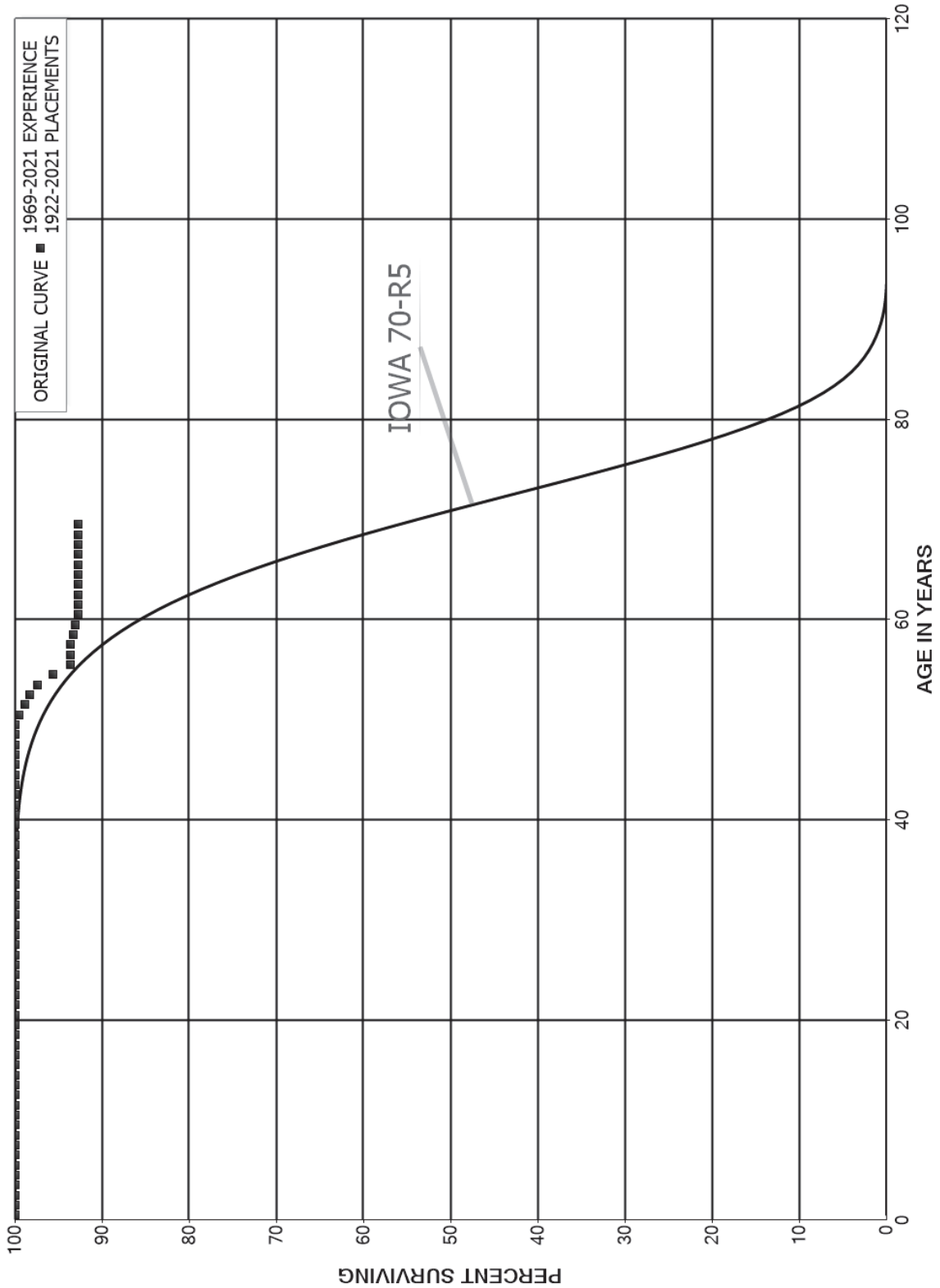
ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1895-2021 EXPERIENCE BAND 1957-2021

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	2,334	464	0.1987	0.8013	0.03
80.5	1,870	28	0.0148	0.9852	0.02
81.5	1,843	26	0.0140	0.9860	0.02
82.5	1,817	13	0.0071	0.9929	0.02
83.5	1,804	253	0.1401	0.8599	0.02
84.5	1,551		0.0000	1.0000	0.02
85.5	1,551		0.0000	1.0000	0.02
86.5	1,551		0.0000	1.0000	0.02
87.5	1,551		0.0000	1.0000	0.02
88.5	1,551		0.0000	1.0000	0.02
89.5	1,551		0.0000	1.0000	0.02
90.5	1,551		0.0000	1.0000	0.02
91.5	1,551		0.0000	1.0000	0.02
92.5	1,551	0	0.0003	0.9997	0.02
93.5	1,551	0	0.0001	0.9999	0.02
94.5	1,550	0	0.0001	0.9999	0.02
95.5	1,550	2	0.0013	0.9987	0.02
96.5	1,548		0.0000	1.0000	0.02
97.5	2,020		0.0000	1.0000	0.02
98.5	2,020		0.0000	1.0000	0.02
99.5	2,020		0.0000	1.0000	0.02
100.5	2,020		0.0000	1.0000	0.02
101.5	2,020		0.0000	1.0000	0.02
102.5	2,020		0.0000	1.0000	0.02
103.5	2,020	542	0.2684	0.7316	0.02
104.5	1,477	87	0.0587	0.9413	0.01
105.5	1,383	306	0.2215	0.7785	0.01
106.5	1,077		0.0000	1.0000	0.01
107.5	1,077		0.0000	1.0000	0.01
108.5	1,077		0.0000	1.0000	0.01
109.5	1,077		0.0000	1.0000	0.01
110.5	1,077		0.0000	1.0000	0.01
111.5	1,077		0.0000	1.0000	0.01
112.5	1,077	1,077	1.0000		0.01
113.5					

JERSEY CENTRAL POWER & LIGHT COMPANY
ACCOUNT 365.10 OVERHEAD CONDUCTORS AND DEVICES - CLEARING
ORIGINAL AND SMOOTH SURVIVOR CURVES



JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 365.10 OVERHEAD CONDUCTORS AND DEVICES - CLEARING

ORIGINAL LIFE TABLE

PLACEMENT BAND 1922-2021 EXPERIENCE BAND 1969-2021

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	202,771,303		0.0000	1.0000	100.00
0.5	199,198,826	220	0.0000	1.0000	100.00
1.5	190,935,293		0.0000	1.0000	100.00
2.5	171,591,714		0.0000	1.0000	100.00
3.5	152,820,041		0.0000	1.0000	100.00
4.5	134,349,986		0.0000	1.0000	100.00
5.5	137,703,266		0.0000	1.0000	100.00
6.5	134,330,325		0.0000	1.0000	100.00
7.5	123,244,636		0.0000	1.0000	100.00
8.5	81,401,883		0.0000	1.0000	100.00
9.5	81,761,984		0.0000	1.0000	100.00
10.5	72,293,806		0.0000	1.0000	100.00
11.5	66,325,000		0.0000	1.0000	100.00
12.5	45,669,434		0.0000	1.0000	100.00
13.5	40,945,072		0.0000	1.0000	100.00
14.5	40,174,811		0.0000	1.0000	100.00
15.5	37,348,841		0.0000	1.0000	100.00
16.5	37,409,799		0.0000	1.0000	100.00
17.5	32,651,032		0.0000	1.0000	100.00
18.5	32,605,281		0.0000	1.0000	100.00
19.5	32,313,025		0.0000	1.0000	100.00
20.5	31,940,502		0.0000	1.0000	100.00
21.5	31,637,526		0.0000	1.0000	100.00
22.5	30,757,011		0.0000	1.0000	100.00
23.5	27,942,007		0.0000	1.0000	100.00
24.5	26,828,626		0.0000	1.0000	100.00
25.5	25,452,295		0.0000	1.0000	100.00
26.5	24,643,919		0.0000	1.0000	100.00
27.5	23,850,423		0.0000	1.0000	100.00
28.5	22,894,493		0.0000	1.0000	100.00
29.5	21,717,118		0.0000	1.0000	100.00
30.5	20,916,706		0.0000	1.0000	100.00
31.5	20,455,926		0.0000	1.0000	100.00
32.5	19,717,948		0.0000	1.0000	100.00
33.5	18,875,910		0.0000	1.0000	100.00
34.5	18,266,878		0.0000	1.0000	100.00
35.5	17,302,367		0.0000	1.0000	100.00
36.5	16,847,001		0.0000	1.0000	100.00
37.5	16,307,146		0.0000	1.0000	100.00
38.5	15,847,524		0.0000	1.0000	100.00

JERSEY CENTRAL POWER & LIGHT COMPANY

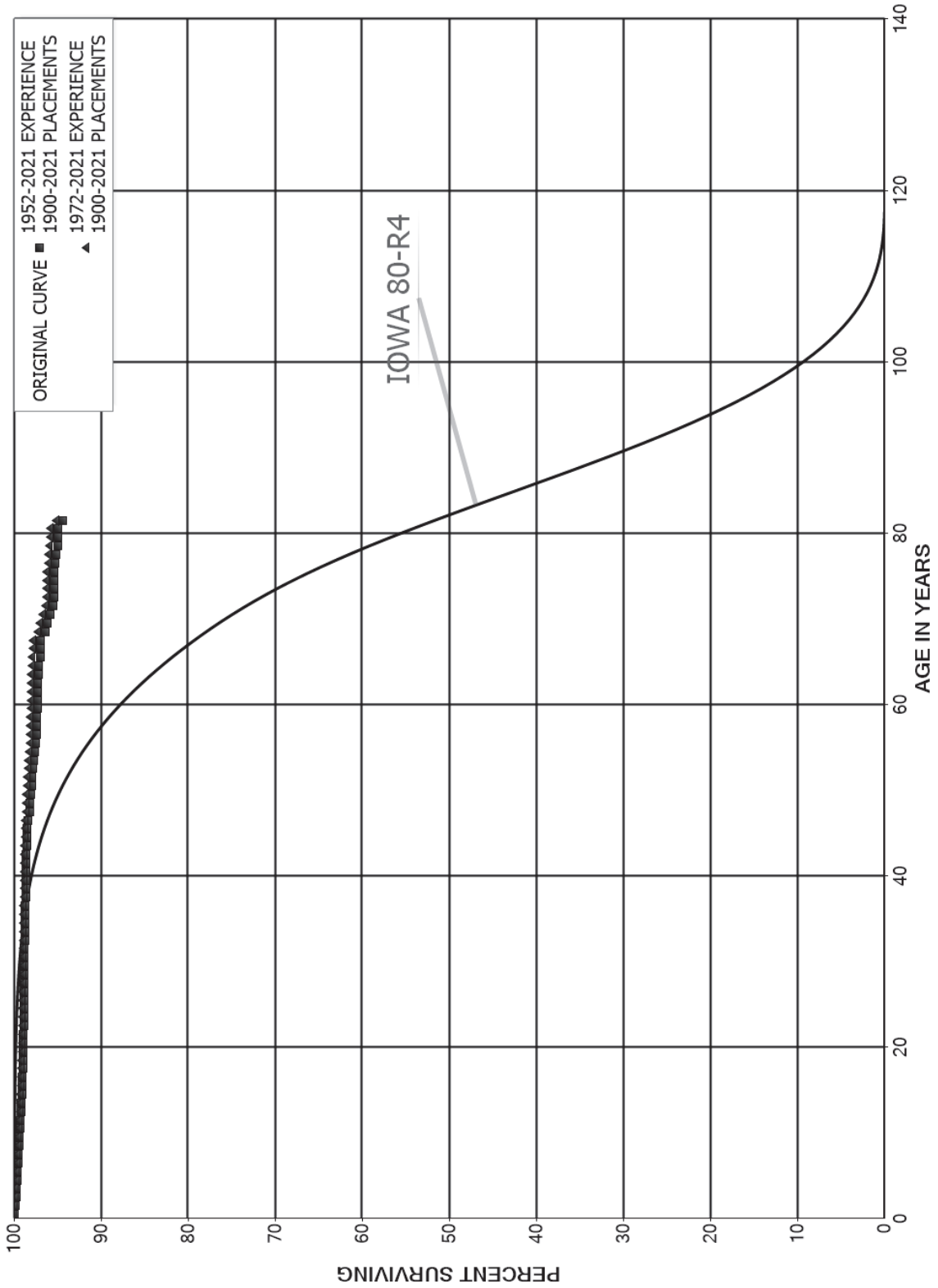
ACCOUNT 365.10 OVERHEAD CONDUCTORS AND DEVICES - CLEARING

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1922-2021 EXPERIENCE BAND 1969-2021

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	15,379,842		0.0000	1.0000	100.00
40.5	14,801,067		0.0000	1.0000	100.00
41.5	13,904,350		0.0000	1.0000	100.00
42.5	12,828,166		0.0000	1.0000	100.00
43.5	12,378,767		0.0000	1.0000	100.00
44.5	11,998,001		0.0000	1.0000	100.00
45.5	11,624,587		0.0000	1.0000	100.00
46.5	11,255,427		0.0000	1.0000	100.00
47.5	10,524,313		0.0000	1.0000	100.00
48.5	9,656,051		0.0000	1.0000	100.00
49.5	8,779,984	39,072	0.0045	0.9955	100.00
50.5	8,044,947	58,996	0.0073	0.9927	99.55
51.5	7,256,338	40,509	0.0056	0.9944	98.82
52.5	6,090,150	52,446	0.0086	0.9914	98.27
53.5	5,330,996	101,857	0.0191	0.9809	97.43
54.5	4,473,361	89,159	0.0199	0.9801	95.57
55.5	3,973,989	323	0.0001	0.9999	93.66
56.5	3,576,705	872	0.0002	0.9998	93.65
57.5	2,846,927	11,883	0.0042	0.9958	93.63
58.5	2,391,955	5,297	0.0022	0.9978	93.24
59.5	1,878,624	5,286	0.0028	0.9972	93.03
60.5	1,550,473		0.0000	1.0000	92.77
61.5	1,271,499		0.0000	1.0000	92.77
62.5	911,452		0.0000	1.0000	92.77
63.5	711,709		0.0000	1.0000	92.77
64.5	641,403		0.0000	1.0000	92.77
65.5	571,831		0.0000	1.0000	92.77
66.5	482,106		0.0000	1.0000	92.77
67.5	420,977		0.0000	1.0000	92.77
68.5	344,641		0.0000	1.0000	92.77
69.5	288,605	1,038	0.0036	0.9964	92.77
70.5	233,493	27	0.0001	0.9999	92.44
71.5	192,957	280	0.0014	0.9986	92.43
72.5	140,232	63	0.0004	0.9996	92.29
73.5	87,310		0.0000	1.0000	92.25
74.5	27,438		0.0000	1.0000	92.25
75.5	277		0.0000	1.0000	92.25
76.5	277	277	1.0000		92.25
77.5					

JERSEY CENTRAL POWER & LIGHT COMPANY
ACCOUNT 366.00 UNDERGROUND CONDUIT
ORIGINAL AND SMOOTH SURVIVOR CURVES



JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 366.00 UNDERGROUND CONDUIT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1900-2021 EXPERIENCE BAND 1952-2021

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	120,653,611	42,296	0.0004	0.9996	100.00
0.5	117,822,188	155,474	0.0013	0.9987	99.96
1.5	115,332,413	67,855	0.0006	0.9994	99.83
2.5	114,100,902	90,853	0.0008	0.9992	99.77
3.5	112,877,394	41,503	0.0004	0.9996	99.69
4.5	112,801,710	63,353	0.0006	0.9994	99.66
5.5	112,430,458	85,689	0.0008	0.9992	99.60
6.5	112,507,838	48,202	0.0004	0.9996	99.53
7.5	112,063,094	51,096	0.0005	0.9995	99.48
8.5	111,973,805	73,941	0.0007	0.9993	99.44
9.5	111,201,414	72,009	0.0006	0.9994	99.37
10.5	110,427,642	74,657	0.0007	0.9993	99.31
11.5	110,007,462	71,988	0.0007	0.9993	99.24
12.5	109,137,906	42,035	0.0004	0.9996	99.18
13.5	108,744,187	39,271	0.0004	0.9996	99.14
14.5	108,808,406	36,753	0.0003	0.9997	99.10
15.5	108,478,890	33,654	0.0003	0.9997	99.07
16.5	108,245,220	35,187	0.0003	0.9997	99.04
17.5	108,130,513	17,718	0.0002	0.9998	99.01
18.5	106,924,338	36,603	0.0003	0.9997	98.99
19.5	101,307,295	11,357	0.0001	0.9999	98.96
20.5	96,401,653	45,775	0.0005	0.9995	98.94
21.5	94,067,177	22,933	0.0002	0.9998	98.90
22.5	93,457,081	4,810	0.0001	0.9999	98.87
23.5	86,818,678	6,627	0.0001	0.9999	98.87
24.5	81,970,410	14,830	0.0002	0.9998	98.86
25.5	75,638,192	3,681	0.0000	1.0000	98.84
26.5	63,409,397	5,391	0.0001	0.9999	98.84
27.5	56,710,396	6,633	0.0001	0.9999	98.83
28.5	52,587,222	2,828	0.0001	0.9999	98.82
29.5	48,848,105	2,247	0.0000	1.0000	98.81
30.5	44,706,825	5,233	0.0001	0.9999	98.81
31.5	41,913,759	14,637	0.0003	0.9997	98.80
32.5	38,281,175	13,354	0.0003	0.9997	98.76
33.5	34,109,061	1,862	0.0001	0.9999	98.73
34.5	31,456,413	2,128	0.0001	0.9999	98.72
35.5	28,731,911	2,734	0.0001	0.9999	98.72
36.5	26,156,342	11,072	0.0004	0.9996	98.71
37.5	24,702,996	4,335	0.0002	0.9998	98.66
38.5	23,328,083	4,420	0.0002	0.9998	98.65

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 366.00 UNDERGROUND CONDUIT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2021 EXPERIENCE BAND 1952-2021

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	22,122,913	1,027	0.0000	1.0000	98.63
40.5	20,768,994	3,084	0.0001	0.9999	98.62
41.5	19,478,122	2,547	0.0001	0.9999	98.61
42.5	17,698,692	9,334	0.0005	0.9995	98.60
43.5	16,442,138	4,996	0.0003	0.9997	98.54
44.5	15,608,318	6,591	0.0004	0.9996	98.51
45.5	13,573,891	11,663	0.0009	0.9991	98.47
46.5	12,117,232	30,315	0.0025	0.9975	98.39
47.5	10,051,433	1,267	0.0001	0.9999	98.14
48.5	7,725,229	7,364	0.0010	0.9990	98.13
49.5	7,360,763	3,560	0.0005	0.9995	98.04
50.5	6,773,715	3,509	0.0005	0.9995	97.99
51.5	6,131,659	8,783	0.0014	0.9986	97.94
52.5	5,574,547	6,337	0.0011	0.9989	97.80
53.5	4,827,338	3,576	0.0007	0.9993	97.69
54.5	4,412,964	6,784	0.0015	0.9985	97.61
55.5	3,915,786	1,426	0.0004	0.9996	97.46
56.5	3,752,227	376	0.0001	0.9999	97.43
57.5	3,585,728	2,630	0.0007	0.9993	97.42
58.5	3,292,676	1,235	0.0004	0.9996	97.35
59.5	2,952,139	1,479	0.0005	0.9995	97.31
60.5	2,883,486	399	0.0001	0.9999	97.26
61.5	2,632,185	347	0.0001	0.9999	97.25
62.5	2,393,072	641	0.0003	0.9997	97.24
63.5	2,001,108	1,289	0.0006	0.9994	97.21
64.5	1,378,417	2,199	0.0016	0.9984	97.15
65.5	1,220,830	334	0.0003	0.9997	96.99
66.5	1,091,058	234	0.0002	0.9998	96.97
67.5	1,009,508	5,694	0.0056	0.9944	96.94
68.5	961,430	2,181	0.0023	0.9977	96.40
69.5	934,352	3,492	0.0037	0.9963	96.18
70.5	886,357	2,510	0.0028	0.9972	95.82
71.5	879,397	1,432	0.0016	0.9984	95.55
72.5	864,259	80	0.0001	0.9999	95.39
73.5	857,955	16	0.0000	1.0000	95.38
74.5	850,619	1	0.0000	1.0000	95.38
75.5	847,411	1,348	0.0016	0.9984	95.38
76.5	846,632	208	0.0002	0.9998	95.23
77.5	845,307	1,763	0.0021	0.9979	95.21
78.5	843,382	342	0.0004	0.9996	95.01

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 366.00 UNDERGROUND CONDUIT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2021 EXPERIENCE BAND 1952-2021

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	833,210	327	0.0004	0.9996	94.97
80.5	819,826	5,042	0.0061	0.9939	94.93
81.5	795,506		0.0000	1.0000	94.35
82.5	776,432		0.0000	1.0000	94.35
83.5	758,934		0.0000	1.0000	94.35
84.5	739,154		0.0000	1.0000	94.35
85.5	680,070	6,028	0.0089	0.9911	94.35
86.5	650,430	5,647	0.0087	0.9913	93.51
87.5	630,851	5,395	0.0086	0.9914	92.70
88.5	617,486	109	0.0002	0.9998	91.91
89.5	609,652	101	0.0002	0.9998	91.89
90.5	498,629	7,503	0.0150	0.9850	91.88
91.5	378,308		0.0000	1.0000	90.49
92.5	241,147		0.0000	1.0000	90.49
93.5	235,010		0.0000	1.0000	90.49
94.5	233,635		0.0000	1.0000	90.49
95.5	233,558		0.0000	1.0000	90.49
96.5	233,558	1,025	0.0044	0.9956	90.49
97.5	232,818		0.0000	1.0000	90.10
98.5	223,116	21	0.0001	0.9999	90.10
99.5	223,095	24	0.0001	0.9999	90.09
100.5	204,157	14	0.0001	0.9999	90.08
101.5	201,671		0.0000	1.0000	90.07
102.5	201,671		0.0000	1.0000	90.07
103.5	201,671		0.0000	1.0000	90.07
104.5	201,671		0.0000	1.0000	90.07
105.5	201,671		0.0000	1.0000	90.07
106.5	201,671		0.0000	1.0000	90.07
107.5	201,671		0.0000	1.0000	90.07
108.5	5,462		0.0000	1.0000	90.07
109.5	5,462	1,172	0.2146	0.7854	90.07
110.5	897	897	1.0000		70.74
111.5					

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 366.00 UNDERGROUND CONDUIT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1900-2021 EXPERIENCE BAND 1972-2021

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	113,784,592	39,343	0.0003	0.9997	100.00
0.5	111,885,084	151,284	0.0014	0.9986	99.97
1.5	110,195,949	65,480	0.0006	0.9994	99.83
2.5	109,453,285	89,456	0.0008	0.9992	99.77
3.5	109,067,220	39,447	0.0004	0.9996	99.69
4.5	109,414,636	61,278	0.0006	0.9994	99.65
5.5	109,484,435	83,631	0.0008	0.9992	99.60
6.5	109,703,800	42,178	0.0004	0.9996	99.52
7.5	109,389,943	46,904	0.0004	0.9996	99.48
8.5	109,546,823	61,963	0.0006	0.9994	99.44
9.5	109,088,376	70,317	0.0006	0.9994	99.38
10.5	108,502,842	69,108	0.0006	0.9994	99.32
11.5	108,291,146	63,800	0.0006	0.9994	99.26
12.5	107,612,119	41,271	0.0004	0.9996	99.20
13.5	107,588,235	39,178	0.0004	0.9996	99.16
14.5	108,156,008	36,512	0.0003	0.9997	99.12
15.5	107,935,254	30,884	0.0003	0.9997	99.09
16.5	107,783,845	11,238	0.0001	0.9999	99.06
17.5	107,767,944	17,210	0.0002	0.9998	99.05
18.5	106,593,264	35,301	0.0003	0.9997	99.04
19.5	100,921,393	9,541	0.0001	0.9999	99.00
20.5	95,948,314	45,633	0.0005	0.9995	98.99
21.5	93,574,247	22,762	0.0002	0.9998	98.95
22.5	92,871,553	4,157	0.0000	1.0000	98.92
23.5	86,202,322	5,126	0.0001	0.9999	98.92
24.5	81,351,228	14,005	0.0002	0.9998	98.91
25.5	75,026,552	2,254	0.0000	1.0000	98.90
26.5	62,792,921	3,278	0.0001	0.9999	98.89
27.5	56,092,217	1,527	0.0000	1.0000	98.89
28.5	51,959,957	1,927	0.0000	1.0000	98.88
29.5	48,225,686	979	0.0000	1.0000	98.88
30.5	44,055,779	2,593	0.0001	0.9999	98.88
31.5	41,282,599	12,846	0.0003	0.9997	98.87
32.5	37,664,201	12,318	0.0003	0.9997	98.84
33.5	33,474,952	1,628	0.0000	1.0000	98.81
34.5	30,851,138	562	0.0000	1.0000	98.81
35.5	28,137,716	564	0.0000	1.0000	98.80
36.5	25,621,860	8,850	0.0003	0.9997	98.80
37.5	24,175,305	1,334	0.0001	0.9999	98.77
38.5	22,725,655	807	0.0000	1.0000	98.76

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 366.00 UNDERGROUND CONDUIT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2021 EXPERIENCE BAND 1972-2021

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	21,577,688	1,027	0.0000	1.0000	98.76
40.5	20,318,232	2,474	0.0001	0.9999	98.75
41.5	19,062,097	2,512	0.0001	0.9999	98.74
42.5	17,340,978	8,359	0.0005	0.9995	98.73
43.5	16,120,882	3,832	0.0002	0.9998	98.68
44.5	15,299,172	1,032	0.0001	0.9999	98.66
45.5	13,270,466	8,698	0.0007	0.9993	98.65
46.5	11,819,897	14,437	0.0012	0.9988	98.59
47.5	9,767,302	1,100	0.0001	0.9999	98.47
48.5	7,455,032	228	0.0000	1.0000	98.46
49.5	7,102,799	2,452	0.0003	0.9997	98.45
50.5	6,546,626	79	0.0000	1.0000	98.42
51.5	5,908,273	5,395	0.0009	0.9991	98.42
52.5	5,360,212	4,837	0.0009	0.9991	98.33
53.5	4,650,289	2,755	0.0006	0.9994	98.24
54.5	4,239,673	3,065	0.0007	0.9993	98.18
55.5	3,769,127	8	0.0000	1.0000	98.11
56.5	3,608,915	143	0.0000	1.0000	98.11
57.5	3,443,520	2,281	0.0007	0.9993	98.10
58.5	3,224,894	1,191	0.0004	0.9996	98.04
59.5	2,900,031	1,312	0.0005	0.9995	98.00
60.5	2,850,008	399	0.0001	0.9999	97.96
61.5	2,598,707	347	0.0001	0.9999	97.95
62.5	2,385,458	641	0.0003	0.9997	97.93
63.5	1,993,494	764	0.0004	0.9996	97.91
64.5	1,371,328	1,150	0.0008	0.9992	97.87
65.5	1,214,790	334	0.0003	0.9997	97.79
66.5	1,085,018	234	0.0002	0.9998	97.76
67.5	1,007,665	5,694	0.0057	0.9943	97.74
68.5	959,587	2,181	0.0023	0.9977	97.19
69.5	932,509	3,492	0.0037	0.9963	96.97
70.5	884,513	2,510	0.0028	0.9972	96.60
71.5	879,397	1,432	0.0016	0.9984	96.33
72.5	864,259	80	0.0001	0.9999	96.17
73.5	857,955	16	0.0000	1.0000	96.16
74.5	850,619	1	0.0000	1.0000	96.16
75.5	847,411	1,348	0.0016	0.9984	96.16
76.5	846,632	208	0.0002	0.9998	96.01
77.5	845,307	1,763	0.0021	0.9979	95.98
78.5	843,382	342	0.0004	0.9996	95.78

JERSEY CENTRAL POWER & LIGHT COMPANY

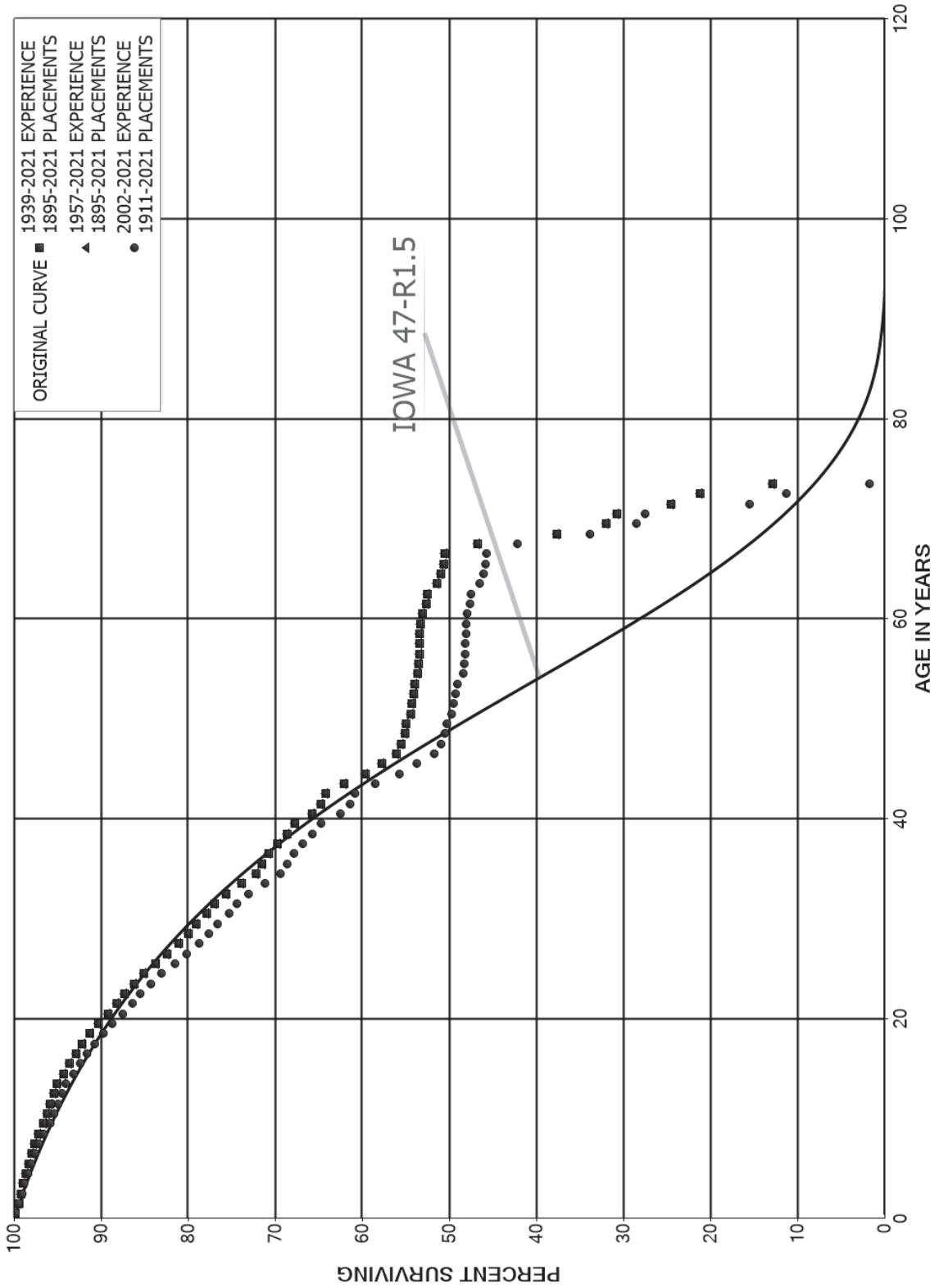
ACCOUNT 366.00 UNDERGROUND CONDUIT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2021 EXPERIENCE BAND 1972-2021

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	833,210	327	0.0004	0.9996	95.75
80.5	819,826	5,042	0.0061	0.9939	95.71
81.5	795,506		0.0000	1.0000	95.12
82.5	776,432		0.0000	1.0000	95.12
83.5	758,934		0.0000	1.0000	95.12
84.5	739,154		0.0000	1.0000	95.12
85.5	680,070	6,028	0.0089	0.9911	95.12
86.5	650,430	5,647	0.0087	0.9913	94.28
87.5	630,851	5,395	0.0086	0.9914	93.46
88.5	617,486	109	0.0002	0.9998	92.66
89.5	609,652	101	0.0002	0.9998	92.64
90.5	498,629	7,503	0.0150	0.9850	92.63
91.5	378,308		0.0000	1.0000	91.23
92.5	241,147		0.0000	1.0000	91.23
93.5	235,010		0.0000	1.0000	91.23
94.5	233,635		0.0000	1.0000	91.23
95.5	233,558		0.0000	1.0000	91.23
96.5	233,558	1,025	0.0044	0.9956	91.23
97.5	232,818		0.0000	1.0000	90.83
98.5	223,116	21	0.0001	0.9999	90.83
99.5	223,095	24	0.0001	0.9999	90.82
100.5	204,157	14	0.0001	0.9999	90.81
101.5	201,671		0.0000	1.0000	90.81
102.5	201,671		0.0000	1.0000	90.81
103.5	201,671		0.0000	1.0000	90.81
104.5	201,671		0.0000	1.0000	90.81
105.5	201,671		0.0000	1.0000	90.81
106.5	201,671		0.0000	1.0000	90.81
107.5	201,671		0.0000	1.0000	90.81
108.5	5,462		0.0000	1.0000	90.81
109.5	5,462	1,172	0.2146	0.7854	90.81
110.5	897	897	1.0000		71.32
111.5					

JERSEY CENTRAL POWER & LIGHT COMPANY
ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1895-2021 EXPERIENCE BAND 1939-2021

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	749,276,845	978,697	0.0013	0.9987	100.00
0.5	714,385,017	3,055,995	0.0043	0.9957	99.87
1.5	681,285,551	1,900,269	0.0028	0.9972	99.44
2.5	648,094,217	1,590,027	0.0025	0.9975	99.16
3.5	598,959,405	1,862,674	0.0031	0.9969	98.92
4.5	578,740,686	1,773,793	0.0031	0.9969	98.61
5.5	552,070,595	1,714,154	0.0031	0.9969	98.31
6.5	519,206,701	1,907,960	0.0037	0.9963	98.01
7.5	486,123,649	2,264,201	0.0047	0.9953	97.65
8.5	460,367,776	2,946,610	0.0064	0.9936	97.19
9.5	409,725,672	1,598,796	0.0039	0.9961	96.57
10.5	391,814,728	1,391,726	0.0036	0.9964	96.19
11.5	373,393,257	1,582,314	0.0042	0.9958	95.85
12.5	351,528,666	1,553,301	0.0044	0.9956	95.44
13.5	326,439,429	2,394,793	0.0073	0.9927	95.02
14.5	316,865,228	2,291,468	0.0072	0.9928	94.33
15.5	295,293,507	2,464,463	0.0083	0.9917	93.64
16.5	273,434,999	2,156,366	0.0079	0.9921	92.86
17.5	260,824,354	2,508,661	0.0096	0.9904	92.13
18.5	248,138,356	2,599,298	0.0105	0.9895	91.24
19.5	236,469,546	2,784,415	0.0118	0.9882	90.29
20.5	222,228,208	2,632,981	0.0118	0.9882	89.22
21.5	208,113,433	2,119,750	0.0102	0.9898	88.17
22.5	193,715,913	2,339,224	0.0121	0.9879	87.27
23.5	174,517,891	2,249,902	0.0129	0.9871	86.22
24.5	160,285,958	2,700,941	0.0169	0.9831	85.10
25.5	147,842,851	2,197,016	0.0149	0.9851	83.67
26.5	137,858,595	2,268,313	0.0165	0.9835	82.43
27.5	128,583,439	1,725,684	0.0134	0.9866	81.07
28.5	114,914,829	1,371,346	0.0119	0.9881	79.98
29.5	101,838,655	1,571,907	0.0154	0.9846	79.03
30.5	85,320,397	972,792	0.0114	0.9886	77.81
31.5	75,993,656	1,246,143	0.0164	0.9836	76.92
32.5	65,164,638	1,550,257	0.0238	0.9762	75.66
33.5	53,204,455	1,210,312	0.0227	0.9773	73.86
34.5	46,090,352	465,330	0.0101	0.9899	72.18
35.5	40,671,496	412,293	0.0101	0.9899	71.45
36.5	34,502,983	514,863	0.0149	0.9851	70.73
37.5	31,818,044	482,436	0.0152	0.9848	69.67
38.5	29,453,661	394,646	0.0134	0.9866	68.61

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1895-2021 EXPERIENCE BAND 1939-2021

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	26,845,674	778,489	0.0290	0.9710	67.70
40.5	23,828,148	370,512	0.0155	0.9845	65.73
41.5	21,420,076	186,532	0.0087	0.9913	64.71
42.5	19,157,130	631,123	0.0329	0.9671	64.15
43.5	16,472,255	644,529	0.0391	0.9609	62.03
44.5	14,564,963	449,193	0.0308	0.9692	59.61
45.5	12,944,147	370,686	0.0286	0.9714	57.77
46.5	11,683,617	133,502	0.0114	0.9886	56.11
47.5	10,065,807	76,376	0.0076	0.9924	55.47
48.5	8,593,633	20,905	0.0024	0.9976	55.05
49.5	8,087,949	74,226	0.0092	0.9908	54.92
50.5	6,858,585	19,329	0.0028	0.9972	54.41
51.5	6,527,126	18,894	0.0029	0.9971	54.26
52.5	6,457,203	17,520	0.0027	0.9973	54.10
53.5	5,573,172	40,782	0.0073	0.9927	53.96
54.5	5,020,277	3,566	0.0007	0.9993	53.56
55.5	4,667,953	7,220	0.0015	0.9985	53.52
56.5	4,454,544	3,074	0.0007	0.9993	53.44
57.5	4,226,877	3,677	0.0009	0.9991	53.40
58.5	4,024,800	4,725	0.0012	0.9988	53.36
59.5	3,968,066	16,838	0.0042	0.9958	53.29
60.5	3,718,595	32,041	0.0086	0.9914	53.07
61.5	3,684,268	9,962	0.0027	0.9973	52.61
62.5	3,379,496	68,461	0.0203	0.9797	52.47
63.5	3,121,869	28,551	0.0091	0.9909	51.41
64.5	2,777,667	16,431	0.0059	0.9941	50.94
65.5	2,716,546	9,811	0.0036	0.9964	50.63
66.5	2,634,764	197,234	0.0749	0.9251	50.45
67.5	2,368,447	457,593	0.1932	0.8068	46.68
68.5	1,879,335	283,635	0.1509	0.8491	37.66
69.5	1,581,457	63,007	0.0398	0.9602	31.97
70.5	74,263	15,045	0.2026	0.7974	30.70
71.5	59,325	8,030	0.1354	0.8646	24.48
72.5	39,796	15,759	0.3960	0.6040	21.17
73.5	23,087	5,063	0.2193	0.7807	12.79
74.5	17,483	616	0.0352	0.9648	9.98
75.5	16,868	128	0.0076	0.9924	9.63
76.5	16,851	1	0.0000	1.0000	9.56
77.5	15,791	3	0.0002	0.9998	9.56
78.5	15,958	177	0.0111	0.9889	9.55

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1895-2021 EXPERIENCE BAND 1939-2021

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	15,849	144	0.0091	0.9909	9.45
80.5	15,705	121	0.0077	0.9923	9.36
81.5	15,584	8	0.0005	0.9995	9.29
82.5	15,576	45	0.0029	0.9971	9.29
83.5	15,532	0	0.0000	1.0000	9.26
84.5	15,532		0.0000	1.0000	9.26
85.5	15,532	7,558	0.4866	0.5134	9.26
86.5	7,974	3,187	0.3997	0.6003	4.75
87.5	4,786	1,598	0.3339	0.6661	2.85
88.5	3,188	3,188	1.0000		1.90
89.5					
90.5					
91.5					
92.5					
93.5					
94.5					
95.5					
96.5					
97.5					
98.5					
99.5					
100.5					
101.5					
102.5					
103.5					
104.5					
105.5	7	7	1.0000		
106.5					

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1895-2021 EXPERIENCE BAND 1957-2021

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	746,405,635	978,697	0.0013	0.9987	100.00
0.5	711,607,497	3,055,464	0.0043	0.9957	99.87
1.5	678,633,915	1,898,673	0.0028	0.9972	99.44
2.5	645,511,084	1,588,767	0.0025	0.9975	99.16
3.5	596,441,681	1,857,891	0.0031	0.9969	98.92
4.5	576,270,584	1,771,143	0.0031	0.9969	98.61
5.5	549,626,359	1,712,844	0.0031	0.9969	98.31
6.5	516,778,024	1,904,847	0.0037	0.9963	98.00
7.5	483,717,636	2,264,201	0.0047	0.9953	97.64
8.5	457,964,894	2,945,024	0.0064	0.9936	97.18
9.5	407,320,119	1,598,599	0.0039	0.9961	96.56
10.5	389,399,889	1,391,285	0.0036	0.9964	96.18
11.5	370,971,454	1,582,314	0.0043	0.9957	95.83
12.5	349,084,782	1,553,301	0.0044	0.9956	95.43
13.5	326,350,767	2,392,394	0.0073	0.9927	95.00
14.5	316,770,712	2,291,336	0.0072	0.9928	94.30
15.5	295,193,568	2,464,149	0.0083	0.9917	93.62
16.5	273,317,602	2,156,184	0.0079	0.9921	92.84
17.5	260,722,829	2,508,419	0.0096	0.9904	92.11
18.5	248,010,329	2,599,052	0.0105	0.9895	91.22
19.5	236,294,531	2,784,415	0.0118	0.9882	90.27
20.5	222,014,969	2,632,665	0.0119	0.9881	89.20
21.5	207,904,503	2,118,239	0.0102	0.9898	88.14
22.5	193,483,967	2,338,969	0.0121	0.9879	87.25
23.5	174,317,297	2,248,426	0.0129	0.9871	86.19
24.5	160,145,635	2,697,151	0.0168	0.9832	85.08
25.5	147,758,968	2,196,504	0.0149	0.9851	83.65
26.5	137,795,982	2,257,038	0.0164	0.9836	82.40
27.5	128,553,333	1,723,592	0.0134	0.9866	81.05
28.5	114,902,329	1,371,346	0.0119	0.9881	79.97
29.5	101,830,168	1,571,907	0.0154	0.9846	79.01
30.5	85,315,630	972,792	0.0114	0.9886	77.79
31.5	75,989,059	1,246,143	0.0164	0.9836	76.91
32.5	65,160,181	1,550,257	0.0238	0.9762	75.65
33.5	53,200,936	1,210,312	0.0227	0.9773	73.85
34.5	46,087,713	465,330	0.0101	0.9899	72.17
35.5	40,667,341	412,293	0.0101	0.9899	71.44
36.5	34,499,709	514,753	0.0149	0.9851	70.71
37.5	31,815,392	482,436	0.0152	0.9848	69.66
38.5	29,444,329	394,625	0.0134	0.9866	68.60

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1895-2021 EXPERIENCE BAND 1957-2021

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	26,836,378	778,063	0.0290	0.9710	67.68
40.5	23,821,184	369,315	0.0155	0.9845	65.72
41.5	21,414,537	186,066	0.0087	0.9913	64.70
42.5	19,152,317	629,036	0.0328	0.9672	64.14
43.5	16,472,255	644,529	0.0391	0.9609	62.03
44.5	14,564,963	449,193	0.0308	0.9692	59.60
45.5	12,944,147	370,686	0.0286	0.9714	57.77
46.5	11,683,617	133,502	0.0114	0.9886	56.11
47.5	10,065,807	76,376	0.0076	0.9924	55.47
48.5	8,593,633	20,905	0.0024	0.9976	55.05
49.5	8,087,949	74,226	0.0092	0.9908	54.92
50.5	6,858,585	19,329	0.0028	0.9972	54.41
51.5	6,527,126	18,894	0.0029	0.9971	54.26
52.5	6,457,203	17,520	0.0027	0.9973	54.10
53.5	5,573,172	40,782	0.0073	0.9927	53.96
54.5	5,020,277	3,566	0.0007	0.9993	53.56
55.5	4,667,953	7,220	0.0015	0.9985	53.52
56.5	4,454,544	3,074	0.0007	0.9993	53.44
57.5	4,226,877	3,677	0.0009	0.9991	53.40
58.5	4,024,800	4,725	0.0012	0.9988	53.36
59.5	3,968,066	16,838	0.0042	0.9958	53.29
60.5	3,718,595	32,041	0.0086	0.9914	53.07
61.5	3,684,268	9,962	0.0027	0.9973	52.61
62.5	3,379,496	68,461	0.0203	0.9797	52.47
63.5	3,121,869	28,551	0.0091	0.9909	51.41
64.5	2,777,667	16,431	0.0059	0.9941	50.93
65.5	2,716,546	9,811	0.0036	0.9964	50.63
66.5	2,634,764	197,234	0.0749	0.9251	50.45
67.5	2,368,447	457,593	0.1932	0.8068	46.67
68.5	1,879,335	283,635	0.1509	0.8491	37.66
69.5	1,581,457	63,007	0.0398	0.9602	31.97
70.5	74,263	15,045	0.2026	0.7974	30.70
71.5	59,325	8,030	0.1354	0.8646	24.48
72.5	39,796	15,759	0.3960	0.6040	21.17
73.5	23,087	5,063	0.2193	0.7807	12.78
74.5	17,483	616	0.0352	0.9648	9.98
75.5	16,868	128	0.0076	0.9924	9.63
76.5	16,851	1	0.0000	1.0000	9.56
77.5	15,791	3	0.0002	0.9998	9.56
78.5	15,958	177	0.0111	0.9889	9.55

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1895-2021 EXPERIENCE BAND 1957-2021

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	15,849	144	0.0091	0.9909	9.45
80.5	15,705	121	0.0077	0.9923	9.36
81.5	15,584	8	0.0005	0.9995	9.29
82.5	15,576	45	0.0029	0.9971	9.29
83.5	15,532	0	0.0000	1.0000	9.26
84.5	15,532		0.0000	1.0000	9.26
85.5	15,532	7,558	0.4866	0.5134	9.26
86.5	7,974	3,187	0.3997	0.6003	4.75
87.5	4,786	1,598	0.3339	0.6661	2.85
88.5	3,188	3,188	1.0000		1.90
89.5					
90.5					
91.5					
92.5					
93.5					
94.5					
95.5					
96.5					
97.5					
98.5					
99.5					
100.5					
101.5					
102.5					
103.5					
104.5					
105.5	7	7	1.0000		
106.5					

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1911-2021 EXPERIENCE BAND 2002-2021

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	483,866,240	791,477	0.0016	0.9984	100.00
0.5	462,101,632	1,752,178	0.0038	0.9962	99.84
1.5	444,682,497	1,562,813	0.0035	0.9965	99.46
2.5	427,261,608	1,338,123	0.0031	0.9969	99.11
3.5	398,362,162	1,557,890	0.0039	0.9961	98.80
4.5	392,374,124	1,471,023	0.0037	0.9963	98.41
5.5	377,358,638	1,510,942	0.0040	0.9960	98.04
6.5	354,096,953	1,676,227	0.0047	0.9953	97.65
7.5	329,780,220	1,928,511	0.0058	0.9942	97.19
8.5	319,961,350	2,599,294	0.0081	0.9919	96.62
9.5	284,195,247	1,318,974	0.0046	0.9954	95.83
10.5	285,332,711	1,190,384	0.0042	0.9958	95.39
11.5	277,791,485	1,412,848	0.0051	0.9949	94.99
12.5	268,580,185	1,355,869	0.0050	0.9950	94.51
13.5	258,313,202	2,264,052	0.0088	0.9912	94.03
14.5	257,330,053	2,138,057	0.0083	0.9917	93.21
15.5	243,064,545	2,292,552	0.0094	0.9906	92.43
16.5	227,247,617	2,008,016	0.0088	0.9912	91.56
17.5	218,025,231	2,359,732	0.0108	0.9892	90.75
18.5	208,306,067	2,456,299	0.0118	0.9882	89.77
19.5	199,452,863	2,611,545	0.0131	0.9869	88.71
20.5	187,989,279	2,409,285	0.0128	0.9872	87.55
21.5	176,864,970	1,970,823	0.0111	0.9889	86.43
22.5	165,932,507	2,225,788	0.0134	0.9866	85.46
23.5	148,962,101	2,146,255	0.0144	0.9856	84.32
24.5	136,622,874	2,599,691	0.0190	0.9810	83.10
25.5	127,021,735	2,100,442	0.0165	0.9835	81.52
26.5	119,084,790	2,142,072	0.0180	0.9820	80.17
27.5	112,603,351	1,646,829	0.0146	0.9854	78.73
28.5	102,234,908	1,315,932	0.0129	0.9871	77.58
29.5	90,509,269	1,518,230	0.0168	0.9832	76.58
30.5	75,224,345	898,489	0.0119	0.9881	75.30
31.5	67,037,957	1,178,944	0.0176	0.9824	74.40
32.5	57,559,928	1,507,388	0.0262	0.9738	73.09
33.5	46,825,466	1,184,468	0.0253	0.9747	71.18
34.5	40,478,910	454,717	0.0112	0.9888	69.38
35.5	35,474,464	389,724	0.0110	0.9890	68.60
36.5	29,543,735	441,195	0.0149	0.9851	67.84
37.5	27,176,209	466,874	0.0172	0.9828	66.83
38.5	25,033,107	377,996	0.0151	0.9849	65.68

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1911-2021 EXPERIENCE BAND 2002-2021

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	22,620,871	754,540	0.0334	0.9666	64.69
40.5	19,897,194	352,409	0.0177	0.9823	62.53
41.5	17,746,151	170,015	0.0096	0.9904	61.42
42.5	15,806,680	616,869	0.0390	0.9610	60.84
43.5	13,321,665	633,162	0.0475	0.9525	58.46
44.5	11,720,771	421,530	0.0360	0.9640	55.68
45.5	10,170,594	366,416	0.0360	0.9640	53.68
46.5	8,985,554	128,706	0.0143	0.9857	51.75
47.5	7,433,659	72,910	0.0098	0.9902	51.00
48.5	5,997,021	19,552	0.0033	0.9967	50.50
49.5	5,507,377	72,549	0.0132	0.9868	50.34
50.5	4,302,871	17,987	0.0042	0.9958	49.68
51.5	3,980,338	16,836	0.0042	0.9958	49.47
52.5	3,924,105	16,983	0.0043	0.9957	49.26
53.5	3,042,614	40,609	0.0133	0.9867	49.05
54.5	2,490,631	3,213	0.0013	0.9987	48.39
55.5	2,140,325	4,866	0.0023	0.9977	48.33
56.5	1,929,955	2,628	0.0014	0.9986	48.22
57.5	1,704,964	2,457	0.0014	0.9986	48.15
58.5	3,885,413	2,943	0.0008	0.9992	48.08
59.5	3,825,701	6,054	0.0016	0.9984	48.05
60.5	3,574,878	29,637	0.0083	0.9917	47.97
61.5	3,545,137	7,996	0.0023	0.9977	47.57
62.5	3,258,684	67,553	0.0207	0.9793	47.47
63.5	3,003,493	26,762	0.0089	0.9911	46.48
64.5	2,663,201	14,392	0.0054	0.9946	46.07
65.5	2,606,905	6,257	0.0024	0.9976	45.82
66.5	2,538,316	194,404	0.0766	0.9234	45.71
67.5	2,278,704	453,655	0.1991	0.8009	42.21
68.5	1,802,694	280,305	0.1555	0.8445	33.81
69.5	1,516,940	58,157	0.0383	0.9617	28.55
70.5	25,522	11,139	0.4364	0.5636	27.45
71.5	19,690	5,313	0.2698	0.7302	15.47
72.5	17,843	15,062	0.8442	0.1558	11.30
73.5	6,548	4,925	0.7522	0.2478	1.76
74.5	1,549	486	0.3135	0.6865	0.44
75.5	1,079	128	0.1185	0.8815	0.30
76.5	1,062	1	0.0007	0.9993	0.26
77.5	0	0	1.0000		0.26
78.5	172	172	1.0000		

JERSEY CENTRAL POWER & LIGHT COMPANY

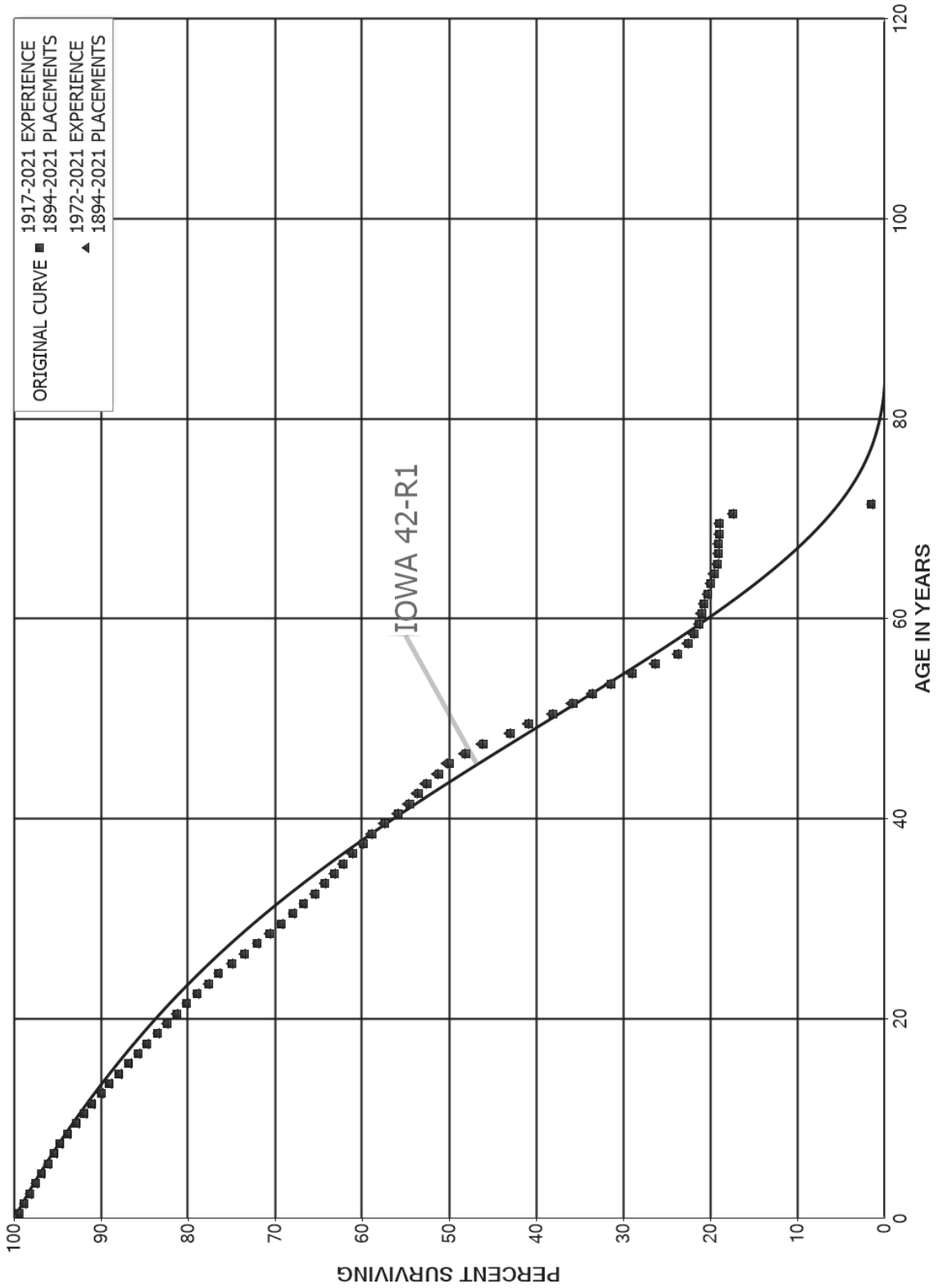
ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1911-2021 EXPERIENCE BAND 2002-2021

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	68	68	1.0000		
80.5	7	7	1.0000		
81.5	8	8	1.0000		
82.5					
83.5	0	0	1.0000		
84.5					
85.5					
86.5					
87.5					
88.5	3,188	3,188	1.0000		
89.5					

JERSEY CENTRAL POWER & LIGHT COMPANY
ACCOUNT 368.00 LINE TRANSFORMERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 368.00 LINE TRANSFORMERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1894-2021 EXPERIENCE BAND 1917-2021

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	1,138,516,172	6,860,667	0.0060	0.9940	100.00
0.5	1,108,445,656	6,210,295	0.0056	0.9944	99.40
1.5	1,066,487,345	6,846,432	0.0064	0.9936	98.84
2.5	1,021,339,244	7,096,390	0.0069	0.9931	98.21
3.5	912,345,917	6,400,281	0.0070	0.9930	97.52
4.5	913,559,577	7,065,506	0.0077	0.9923	96.84
5.5	909,528,436	6,431,431	0.0071	0.9929	96.09
6.5	894,370,835	6,615,595	0.0074	0.9926	95.41
7.5	863,583,963	8,396,162	0.0097	0.9903	94.71
8.5	831,549,441	8,252,874	0.0099	0.9901	93.78
9.5	737,474,117	7,336,307	0.0099	0.9901	92.85
10.5	705,518,336	6,712,183	0.0095	0.9905	91.93
11.5	666,815,813	7,689,749	0.0115	0.9885	91.06
12.5	628,732,272	6,947,742	0.0111	0.9889	90.01
13.5	575,872,442	7,227,187	0.0125	0.9875	89.01
14.5	549,493,444	6,882,752	0.0125	0.9875	87.89
15.5	509,193,578	6,056,395	0.0119	0.9881	86.79
16.5	454,099,064	5,593,855	0.0123	0.9877	85.76
17.5	406,958,180	5,772,683	0.0142	0.9858	84.70
18.5	372,416,106	4,734,222	0.0127	0.9873	83.50
19.5	348,428,563	4,733,571	0.0136	0.9864	82.44
20.5	324,172,258	4,726,454	0.0146	0.9854	81.32
21.5	302,396,310	4,661,940	0.0154	0.9846	80.14
22.5	289,776,367	4,664,608	0.0161	0.9839	78.90
23.5	277,497,271	4,180,334	0.0151	0.9849	77.63
24.5	263,673,631	5,022,130	0.0190	0.9810	76.46
25.5	249,307,532	4,964,576	0.0199	0.9801	75.00
26.5	233,258,849	4,704,223	0.0202	0.9798	73.51
27.5	216,595,431	4,164,400	0.0192	0.9808	72.03
28.5	201,808,453	3,989,587	0.0198	0.9802	70.64
29.5	190,386,283	3,698,331	0.0194	0.9806	69.25
30.5	178,426,921	3,148,424	0.0176	0.9824	67.90
31.5	164,665,883	3,139,857	0.0191	0.9809	66.70
32.5	147,291,594	2,607,025	0.0177	0.9823	65.43
33.5	131,561,642	2,196,776	0.0167	0.9833	64.27
34.5	115,965,893	1,913,387	0.0165	0.9835	63.20
35.5	101,278,758	1,739,456	0.0172	0.9828	62.16
36.5	89,601,653	1,805,018	0.0201	0.9799	61.09
37.5	79,912,594	1,401,878	0.0175	0.9825	59.86
38.5	72,758,224	1,812,522	0.0249	0.9751	58.81

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 368.00 LINE TRANSFORMERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1894-2021 EXPERIENCE BAND 1917-2021

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	67,170,171	1,804,931	0.0269	0.9731	57.34
40.5	62,797,511	1,434,231	0.0228	0.9772	55.80
41.5	59,818,512	1,120,493	0.0187	0.9813	54.53
42.5	55,867,155	1,048,046	0.0188	0.9812	53.51
43.5	51,241,828	1,289,786	0.0252	0.9748	52.50
44.5	46,872,260	1,083,448	0.0231	0.9769	51.18
45.5	42,421,002	1,610,444	0.0380	0.9620	50.00
46.5	39,408,854	1,658,016	0.0421	0.9579	48.10
47.5	31,465,086	2,169,811	0.0690	0.9310	46.08
48.5	24,702,460	1,214,558	0.0492	0.9508	42.90
49.5	20,672,139	1,401,778	0.0678	0.9322	40.79
50.5	16,486,060	987,481	0.0599	0.9401	38.02
51.5	13,824,538	871,487	0.0630	0.9370	35.75
52.5	11,178,056	694,742	0.0622	0.9378	33.49
53.5	9,030,466	706,339	0.0782	0.9218	31.41
54.5	6,562,712	598,849	0.0913	0.9087	28.95
55.5	5,967,197	592,822	0.0993	0.9007	26.31
56.5	5,644,737	282,049	0.0500	0.9500	23.70
57.5	5,363,298	153,363	0.0286	0.9714	22.51
58.5	5,214,261	140,403	0.0269	0.9731	21.87
59.5	5,072,576	74,234	0.0146	0.9854	21.28
60.5	5,004,381	58,896	0.0118	0.9882	20.97
61.5	4,956,702	112,313	0.0227	0.9773	20.72
62.5	4,847,151	71,292	0.0147	0.9853	20.25
63.5	4,779,224	103,505	0.0217	0.9783	19.96
64.5	4,677,973	84,798	0.0181	0.9819	19.52
65.5	4,593,244	28,015	0.0061	0.9939	19.17
66.5	4,567,318	8,946	0.0020	0.9980	19.05
67.5	4,559,343	10,082	0.0022	0.9978	19.02
68.5	4,549,431	10,880	0.0024	0.9976	18.97
69.5	4,541,544	366,396	0.0807	0.9193	18.93
70.5	4,176,432	3,814,325	0.9133	0.0867	17.40
71.5	362,174	191,967	0.5300	0.4700	1.51
72.5	170,449	23,566	0.1383	0.8617	0.71
73.5	34,763	9,370	0.2695	0.7305	0.61
74.5	26,048	2,764	0.1061	0.8939	0.45
75.5	23,919	5,185	0.2168	0.7832	0.40
76.5	18,883	4,483	0.2374	0.7626	0.31
77.5	14,615	1,675	0.1146	0.8854	0.24
78.5	13,221	1,566	0.1184	0.8816	0.21

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 368.00 LINE TRANSFORMERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1894-2021 EXPERIENCE BAND 1917-2021

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	12,481	2,496	0.2000	0.8000	0.19
80.5	10,029	742	0.0740	0.9260	0.15
81.5	9,266	1,519	0.1639	0.8361	0.14
82.5	7,808	1,223	0.1567	0.8433	0.12
83.5	6,632	1,139	0.1717	0.8283	0.10
84.5	5,789	1,223	0.2112	0.7888	0.08
85.5	4,567	645	0.1412	0.8588	0.06
86.5	3,922	1,245	0.3176	0.6824	0.05
87.5	2,676	882	0.3294	0.6706	0.04
88.5	1,795	112	0.0623	0.9377	0.02
89.5	1,683	95	0.0564	0.9436	0.02
90.5	1,588	30	0.0191	0.9809	0.02
91.5	1,557	389	0.2501	0.7499	0.02
92.5	1,168	956	0.8189	0.1811	0.02
93.5	335		0.0000	1.0000	0.00
94.5	335		0.0000	1.0000	0.00
95.5	335	103	0.3066	0.6934	0.00
96.5	232	109	0.4682	0.5318	0.00
97.5	124		0.0000	1.0000	0.00
98.5	124		0.0000	1.0000	0.00
99.5	124		0.0000	1.0000	0.00
100.5	124	124	1.0000		0.00
101.5					

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 368.00 LINE TRANSFORMERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1894-2021 EXPERIENCE BAND 1972-2021

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	1,059,496,326	6,755,253	0.0064	0.9936	100.00
0.5	1,034,944,556	5,856,541	0.0057	0.9943	99.36
1.5	999,883,760	6,529,865	0.0065	0.9935	98.80
2.5	961,961,520	6,804,436	0.0071	0.9929	98.15
3.5	859,263,511	6,109,857	0.0071	0.9929	97.46
4.5	866,905,493	6,786,114	0.0078	0.9922	96.77
5.5	867,491,854	6,170,117	0.0071	0.9929	96.01
6.5	856,133,448	6,347,430	0.0074	0.9926	95.33
7.5	828,120,085	8,132,068	0.0098	0.9902	94.62
8.5	799,082,356	7,972,847	0.0100	0.9900	93.69
9.5	707,976,724	7,053,370	0.0100	0.9900	92.76
10.5	678,889,724	6,417,869	0.0095	0.9905	91.83
11.5	642,884,345	7,400,193	0.0115	0.9885	90.96
12.5	607,317,985	6,641,913	0.0109	0.9891	89.92
13.5	556,143,107	6,930,613	0.0125	0.9875	88.93
14.5	532,158,340	6,577,667	0.0124	0.9876	87.83
15.5	493,664,270	5,760,660	0.0117	0.9883	86.74
16.5	440,243,924	5,313,599	0.0121	0.9879	85.73
17.5	394,440,265	5,483,287	0.0139	0.9861	84.69
18.5	361,081,969	4,451,850	0.0123	0.9877	83.52
19.5	337,982,758	4,473,240	0.0132	0.9868	82.49
20.5	314,672,260	4,541,724	0.0144	0.9856	81.39
21.5	293,650,568	4,501,718	0.0153	0.9847	80.22
22.5	281,638,986	4,516,728	0.0160	0.9840	78.99
23.5	269,922,497	4,070,736	0.0151	0.9849	77.72
24.5	256,444,569	4,898,911	0.0191	0.9809	76.55
25.5	242,296,651	4,858,356	0.0201	0.9799	75.09
26.5	226,342,374	4,598,246	0.0203	0.9797	73.58
27.5	209,786,320	4,053,987	0.0193	0.9807	72.09
28.5	195,154,651	3,891,246	0.0199	0.9801	70.69
29.5	183,870,856	3,563,678	0.0194	0.9806	69.29
30.5	172,191,371	3,060,988	0.0178	0.9822	67.94
31.5	163,060,059	3,055,725	0.0187	0.9813	66.73
32.5	145,860,898	2,529,245	0.0173	0.9827	65.48
33.5	130,228,098	2,116,615	0.0163	0.9837	64.35
34.5	114,774,848	1,844,922	0.0161	0.9839	63.30
35.5	100,199,715	1,676,420	0.0167	0.9833	62.29
36.5	88,592,157	1,736,234	0.0196	0.9804	61.24
37.5	78,975,988	1,337,035	0.0169	0.9831	60.04
38.5	71,902,190	1,756,267	0.0244	0.9756	59.03

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 368.00 LINE TRANSFORMERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1894-2021 EXPERIENCE BAND 1972-2021

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	66,372,210	1,747,887	0.0263	0.9737	57.58
40.5	62,089,639	1,388,702	0.0224	0.9776	56.07
41.5	59,216,423	1,077,798	0.0182	0.9818	54.81
42.5	55,363,601	1,010,013	0.0182	0.9818	53.82
43.5	50,846,861	1,263,919	0.0249	0.9751	52.83
44.5	46,547,245	1,062,596	0.0228	0.9772	51.52
45.5	42,181,017	1,596,121	0.0378	0.9622	50.35
46.5	39,213,502	1,642,464	0.0419	0.9581	48.44
47.5	31,303,651	2,158,797	0.0690	0.9310	46.41
48.5	24,567,888	1,203,258	0.0490	0.9510	43.21
49.5	20,567,159	1,395,091	0.0678	0.9322	41.09
50.5	16,402,059	981,963	0.0599	0.9401	38.31
51.5	13,756,006	867,327	0.0631	0.9369	36.01
52.5	11,122,370	691,935	0.0622	0.9378	33.74
53.5	8,984,061	703,183	0.0783	0.9217	31.64
54.5	6,530,805	597,162	0.0914	0.9086	29.17
55.5	5,941,578	590,463	0.0994	0.9006	26.50
56.5	5,625,096	280,645	0.0499	0.9501	23.87
57.5	5,347,866	152,427	0.0285	0.9715	22.68
58.5	5,204,521	140,014	0.0269	0.9731	22.03
59.5	5,064,791	73,626	0.0145	0.9855	21.44
60.5	4,998,682	58,461	0.0117	0.9883	21.13
61.5	4,952,731	112,128	0.0226	0.9774	20.88
62.5	4,843,679	71,111	0.0147	0.9853	20.41
63.5	4,776,448	103,381	0.0216	0.9784	20.11
64.5	4,675,321	84,462	0.0181	0.9819	19.67
65.5	4,591,475	28,015	0.0061	0.9939	19.32
66.5	4,565,725	8,946	0.0020	0.9980	19.20
67.5	4,557,927	10,082	0.0022	0.9978	19.16
68.5	4,548,301	10,795	0.0024	0.9976	19.12
69.5	4,541,019	366,396	0.0807	0.9193	19.07
70.5	4,175,978	3,814,325	0.9134	0.0866	17.53
71.5	361,720	191,837	0.5303	0.4697	1.52
72.5	170,240	23,542	0.1383	0.8617	0.71
73.5	34,652	9,370	0.2704	0.7296	0.61
74.5	26,011	2,764	0.1063	0.8937	0.45
75.5	23,919	5,185	0.2168	0.7832	0.40
76.5	18,883	4,483	0.2374	0.7626	0.31
77.5	14,615	1,675	0.1146	0.8854	0.24
78.5	13,221	1,566	0.1184	0.8816	0.21

JERSEY CENTRAL POWER & LIGHT COMPANY

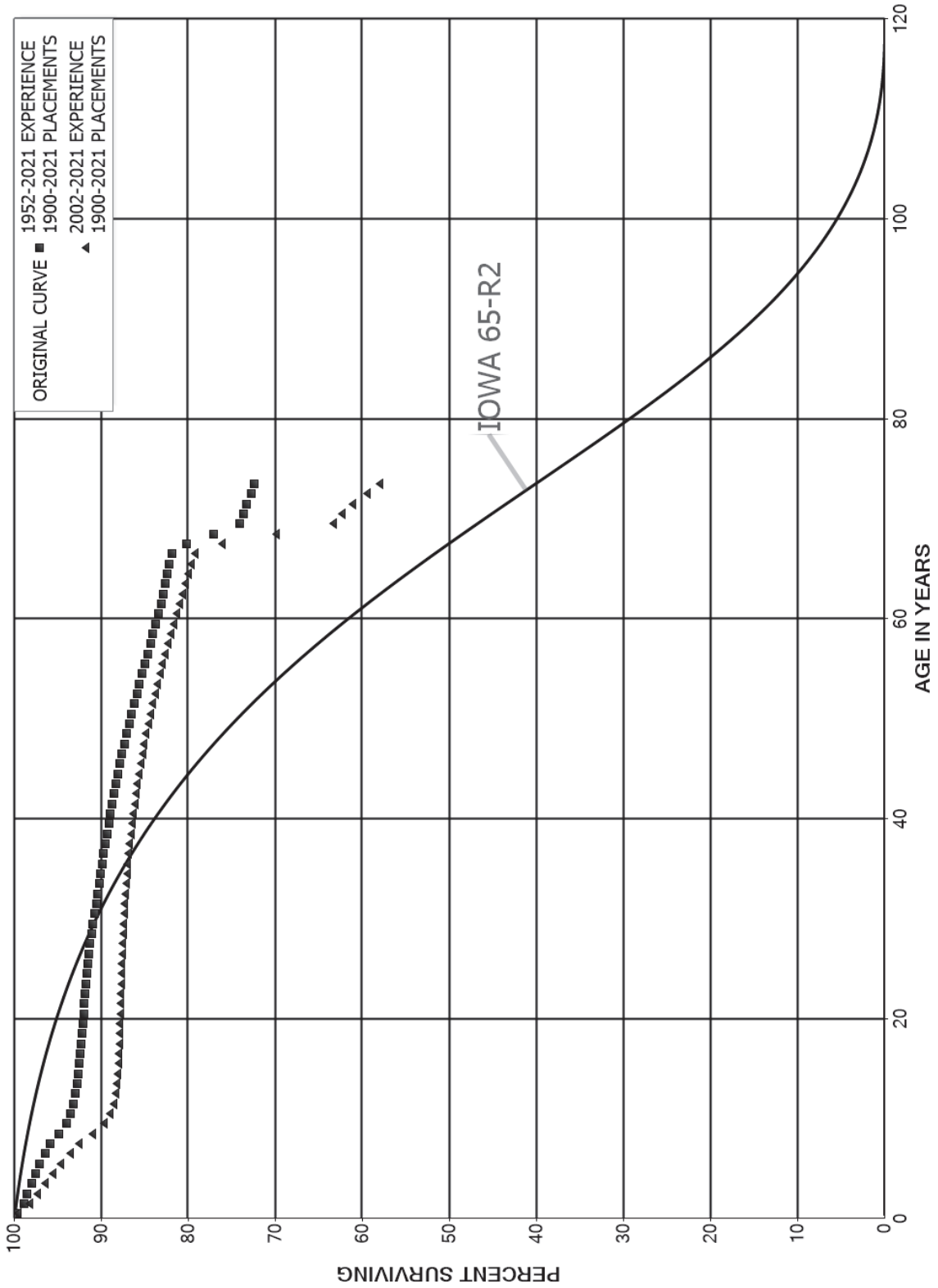
ACCOUNT 368.00 LINE TRANSFORMERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1894-2021 EXPERIENCE BAND 1972-2021

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	12,481	2,496	0.2000	0.8000	0.19
80.5	10,029	742	0.0740	0.9260	0.15
81.5	9,266	1,519	0.1639	0.8361	0.14
82.5	7,808	1,223	0.1567	0.8433	0.12
83.5	6,632	1,139	0.1717	0.8283	0.10
84.5	5,789	1,223	0.2112	0.7888	0.08
85.5	4,567	645	0.1412	0.8588	0.06
86.5	3,922	1,245	0.3176	0.6824	0.05
87.5	2,676	882	0.3294	0.6706	0.04
88.5	1,795	112	0.0623	0.9377	0.03
89.5	1,683	95	0.0564	0.9436	0.02
90.5	1,588	30	0.0191	0.9809	0.02
91.5	1,557	389	0.2501	0.7499	0.02
92.5	1,168	956	0.8189	0.1811	0.02
93.5	335		0.0000	1.0000	0.00
94.5	335		0.0000	1.0000	0.00
95.5	335	103	0.3066	0.6934	0.00
96.5	232	109	0.4682	0.5318	0.00
97.5	124		0.0000	1.0000	0.00
98.5	124		0.0000	1.0000	0.00
99.5	124		0.0000	1.0000	0.00
100.5	124	124	1.0000		0.00
101.5					

JERSEY CENTRAL POWER & LIGHT COMPANY
ACCOUNT 369.00 SERVICES
ORIGINAL AND SMOOTH SURVIVOR CURVES



JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 369.00 SERVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1900-2021 EXPERIENCE BAND 1952-2021

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	498,701,182	1,831,633	0.0037	0.9963	100.00
0.5	488,899,017	3,671,187	0.0075	0.9925	99.63
1.5	486,673,204	2,035,766	0.0042	0.9958	98.88
2.5	479,447,065	2,251,367	0.0047	0.9953	98.47
3.5	462,994,185	2,201,948	0.0048	0.9952	98.01
4.5	460,382,637	2,409,363	0.0052	0.9948	97.54
5.5	455,428,450	2,923,817	0.0064	0.9936	97.03
6.5	450,595,327	2,729,161	0.0061	0.9939	96.41
7.5	442,910,597	4,427,655	0.0100	0.9900	95.83
8.5	434,589,099	4,215,707	0.0097	0.9903	94.87
9.5	418,170,894	2,055,899	0.0049	0.9951	93.95
10.5	411,308,789	1,442,889	0.0035	0.9965	93.49
11.5	405,120,053	1,033,895	0.0026	0.9974	93.16
12.5	401,200,413	672,312	0.0017	0.9983	92.92
13.5	394,917,030	597,702	0.0015	0.9985	92.76
14.5	391,478,206	717,666	0.0018	0.9982	92.62
15.5	388,565,780	439,804	0.0011	0.9989	92.45
16.5	385,710,979	421,305	0.0011	0.9989	92.35
17.5	384,763,395	386,619	0.0010	0.9990	92.25
18.5	377,287,380	369,243	0.0010	0.9990	92.16
19.5	360,803,819	338,422	0.0009	0.9991	92.07
20.5	342,660,751	316,699	0.0009	0.9991	91.98
21.5	325,724,431	290,019	0.0009	0.9991	91.89
22.5	303,906,154	289,226	0.0010	0.9990	91.81
23.5	279,357,984	275,963	0.0010	0.9990	91.72
24.5	256,024,336	270,994	0.0011	0.9989	91.63
25.5	241,334,312	257,965	0.0011	0.9989	91.54
26.5	226,531,612	312,454	0.0014	0.9986	91.44
27.5	211,906,879	534,224	0.0025	0.9975	91.31
28.5	192,577,498	328,117	0.0017	0.9983	91.08
29.5	177,855,187	391,850	0.0022	0.9978	90.93
30.5	166,553,888	386,107	0.0023	0.9977	90.73
31.5	156,649,908	254,958	0.0016	0.9984	90.52
32.5	144,042,819	231,515	0.0016	0.9984	90.37
33.5	131,218,766	229,751	0.0018	0.9982	90.22
34.5	115,716,936	277,787	0.0024	0.9976	90.07
35.5	103,035,289	197,523	0.0019	0.9981	89.85
36.5	91,395,376	179,108	0.0020	0.9980	89.68
37.5	80,074,130	174,772	0.0022	0.9978	89.50
38.5	71,645,844	159,505	0.0022	0.9978	89.31

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 369.00 SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2021 EXPERIENCE BAND 1952-2021

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	66,064,566	154,358	0.0023	0.9977	89.11
40.5	60,719,217	146,297	0.0024	0.9976	88.90
41.5	55,623,786	132,055	0.0024	0.9976	88.69
42.5	50,270,834	118,712	0.0024	0.9976	88.47
43.5	45,135,145	116,863	0.0026	0.9974	88.27
44.5	40,476,501	101,895	0.0025	0.9975	88.04
45.5	36,252,913	101,186	0.0028	0.9972	87.82
46.5	32,466,880	92,743	0.0029	0.9971	87.57
47.5	28,520,495	88,801	0.0031	0.9969	87.32
48.5	24,309,619	80,947	0.0033	0.9967	87.05
49.5	20,878,676	73,867	0.0035	0.9965	86.76
50.5	18,145,744	63,775	0.0035	0.9965	86.45
51.5	16,680,717	57,216	0.0034	0.9966	86.15
52.5	14,389,954	47,825	0.0033	0.9967	85.85
53.5	12,370,129	43,344	0.0035	0.9965	85.57
54.5	10,561,366	37,587	0.0036	0.9964	85.27
55.5	9,085,760	33,036	0.0036	0.9964	84.96
56.5	7,878,211	29,742	0.0038	0.9962	84.66
57.5	6,830,416	26,242	0.0038	0.9962	84.34
58.5	5,922,805	22,569	0.0038	0.9962	84.01
59.5	5,124,718	18,366	0.0036	0.9964	83.69
60.5	4,467,988	14,766	0.0033	0.9967	83.39
61.5	3,851,610	11,435	0.0030	0.9970	83.12
62.5	3,347,825	9,517	0.0028	0.9972	82.87
63.5	2,914,248	8,622	0.0030	0.9970	82.63
64.5	2,523,812	7,314	0.0029	0.9971	82.39
65.5	2,239,168	7,365	0.0033	0.9967	82.15
66.5	1,961,659	41,090	0.0209	0.9791	81.88
67.5	1,713,872	67,133	0.0392	0.9608	80.16
68.5	1,515,200	58,639	0.0387	0.9613	77.02
69.5	1,330,330	6,828	0.0051	0.9949	74.04
70.5	1,251,906	7,174	0.0057	0.9943	73.66
71.5	1,174,140	8,231	0.0070	0.9930	73.24
72.5	1,104,320	5,186	0.0047	0.9953	72.73
73.5	1,046,901	1,391	0.0013	0.9987	72.39
74.5	1,008,107	691	0.0007	0.9993	72.29
75.5	988,677	167	0.0002	0.9998	72.24
76.5	981,219	20	0.0000	1.0000	72.23
77.5	975,997	12	0.0000	1.0000	72.23
78.5	975,583	12	0.0000	1.0000	72.23

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 369.00 SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2021 EXPERIENCE BAND 1952-2021

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	960,910	1,695	0.0018	0.9982	72.23
80.5	931,662	19	0.0000	1.0000	72.10
81.5	908,092	27	0.0000	1.0000	72.10
82.5	906,512		0.0000	1.0000	72.09
83.5	902,823		0.0000	1.0000	72.09
84.5	897,031		0.0000	1.0000	72.09
85.5	892,108	6	0.0000	1.0000	72.09
86.5	887,791	12	0.0000	1.0000	72.09
87.5	886,637	13	0.0000	1.0000	72.09
88.5	885,508	16	0.0000	1.0000	72.09
89.5	884,927		0.0000	1.0000	72.09
90.5	884,267		0.0000	1.0000	72.09
91.5	883,498		0.0000	1.0000	72.09
92.5	883,261		0.0000	1.0000	72.09
93.5	883,189		0.0000	1.0000	72.09
94.5	883,094		0.0000	1.0000	72.09
95.5	882,925		0.0000	1.0000	72.09
96.5	882,925		0.0000	1.0000	72.09
97.5	882,925		0.0000	1.0000	72.09
98.5	882,925		0.0000	1.0000	72.09
99.5	882,925		0.0000	1.0000	72.09
100.5	882,925		0.0000	1.0000	72.09
101.5	882,925		0.0000	1.0000	72.09
102.5	882,925		0.0000	1.0000	72.09
103.5	882,925		0.0000	1.0000	72.09
104.5	882,925		0.0000	1.0000	72.09
105.5	882,925		0.0000	1.0000	72.09
106.5	882,925		0.0000	1.0000	72.09
107.5	882,925		0.0000	1.0000	72.09
108.5	882,925		0.0000	1.0000	72.09
109.5	882,925	412,568	0.4673	0.5327	72.09
110.5	470,357	470,357	1.0000		38.40
111.5					

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 369.00 SERVICES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1900-2021 EXPERIENCE BAND 2002-2021

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	151,868,734	871,533	0.0057	0.9943	100.00
0.5	161,342,517	2,288,940	0.0142	0.9858	99.43
1.5	168,664,049	1,403,290	0.0083	0.9917	98.02
2.5	176,838,277	1,689,575	0.0096	0.9904	97.20
3.5	184,174,024	1,684,156	0.0091	0.9909	96.27
4.5	203,126,256	1,926,996	0.0095	0.9905	95.39
5.5	210,969,495	2,447,949	0.0116	0.9884	94.49
6.5	220,105,777	2,303,754	0.0105	0.9895	93.39
7.5	226,410,200	3,921,746	0.0173	0.9827	92.41
8.5	237,447,799	3,537,108	0.0149	0.9851	90.81
9.5	235,717,816	1,660,723	0.0070	0.9930	89.46
10.5	239,827,719	1,062,535	0.0044	0.9956	88.83
11.5	243,341,614	673,289	0.0028	0.9972	88.44
12.5	251,815,539	322,676	0.0013	0.9987	88.19
13.5	258,434,204	268,316	0.0010	0.9990	88.08
14.5	270,661,399	401,230	0.0015	0.9985	87.99
15.5	280,519,053	133,952	0.0005	0.9995	87.86
16.5	289,448,889	128,834	0.0004	0.9996	87.81
17.5	300,004,444	121,249	0.0004	0.9996	87.77
18.5	301,084,156	134,879	0.0004	0.9996	87.74
19.5	290,271,193	123,074	0.0004	0.9996	87.70
20.5	277,475,486	115,656	0.0004	0.9996	87.66
21.5	265,676,056	99,915	0.0004	0.9996	87.63
22.5	249,307,022	106,509	0.0004	0.9996	87.59
23.5	230,008,071	103,353	0.0004	0.9996	87.56
24.5	211,432,230	106,751	0.0005	0.9995	87.52
25.5	201,053,286	99,649	0.0005	0.9995	87.47
26.5	190,149,844	100,320	0.0005	0.9995	87.43
27.5	179,691,421	105,286	0.0006	0.9994	87.38
28.5	165,055,471	113,187	0.0007	0.9993	87.33
29.5	154,042,108	120,470	0.0008	0.9992	87.27
30.5	145,794,929	129,214	0.0009	0.9991	87.20
31.5	138,569,059	121,381	0.0009	0.9991	87.13
32.5	128,456,688	113,126	0.0009	0.9991	87.05
33.5	117,841,802	121,898	0.0010	0.9990	86.97
34.5	104,335,310	121,253	0.0012	0.9988	86.88
35.5	93,347,399	109,527	0.0012	0.9988	86.78
36.5	83,066,050	109,417	0.0013	0.9987	86.68
37.5	72,947,349	109,288	0.0015	0.9985	86.57
38.5	65,551,694	105,442	0.0016	0.9984	86.44

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 369.00 SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2021 EXPERIENCE BAND 2002-2021

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	60,888,617	104,339	0.0017	0.9983	86.30
40.5	56,309,944	100,985	0.0018	0.9982	86.15
41.5	51,941,874	95,539	0.0018	0.9982	85.99
42.5	47,185,851	86,375	0.0018	0.9982	85.84
43.5	42,570,664	89,639	0.0021	0.9979	85.68
44.5	38,386,090	79,781	0.0021	0.9979	85.50
45.5	34,520,818	82,150	0.0024	0.9976	85.32
46.5	31,078,791	74,194	0.0024	0.9976	85.12
47.5	27,402,900	73,850	0.0027	0.9973	84.92
48.5	23,369,299	69,040	0.0030	0.9970	84.69
49.5	20,104,873	62,724	0.0031	0.9969	84.44
50.5	17,479,251	54,801	0.0031	0.9969	84.17
51.5	15,232,420	49,349	0.0032	0.9968	83.91
52.5	13,031,319	41,238	0.0032	0.9968	83.64
53.5	11,089,604	37,808	0.0034	0.9966	83.37
54.5	9,338,942	32,648	0.0035	0.9965	83.09
55.5	7,895,966	29,238	0.0037	0.9963	82.80
56.5	6,703,646	26,064	0.0039	0.9961	82.49
57.5	5,666,678	23,690	0.0042	0.9958	82.17
58.5	4,765,967	20,141	0.0042	0.9958	81.83
59.5	3,985,083	16,600	0.0042	0.9958	81.48
60.5	3,358,853	13,482	0.0040	0.9960	81.14
61.5	2,778,388	10,235	0.0037	0.9963	80.82
62.5	2,311,886	8,787	0.0038	0.9962	80.52
63.5	1,910,628	8,066	0.0042	0.9958	80.21
64.5	1,551,328	6,988	0.0045	0.9955	79.87
65.5	1,297,819	7,212	0.0056	0.9944	79.51
66.5	1,054,268	40,983	0.0389	0.9611	79.07
67.5	812,083	67,044	0.0826	0.9174	76.00
68.5	619,734	58,591	0.0945	0.9055	69.72
69.5	440,356	6,813	0.0155	0.9845	63.13
70.5	366,788	6,916	0.0189	0.9811	62.16
71.5	290,057	8,230	0.0284	0.9716	60.98
72.5	220,478	5,167	0.0234	0.9766	59.25
73.5	163,151	1,389	0.0085	0.9915	57.86
74.5	124,456	689	0.0055	0.9945	57.37
75.5	105,613	159	0.0015	0.9985	57.05
76.5	98,176	20	0.0002	0.9998	56.97
77.5	92,966	12	0.0001	0.9999	56.96
78.5	92,561	12	0.0001	0.9999	56.95

JERSEY CENTRAL POWER & LIGHT COMPANY

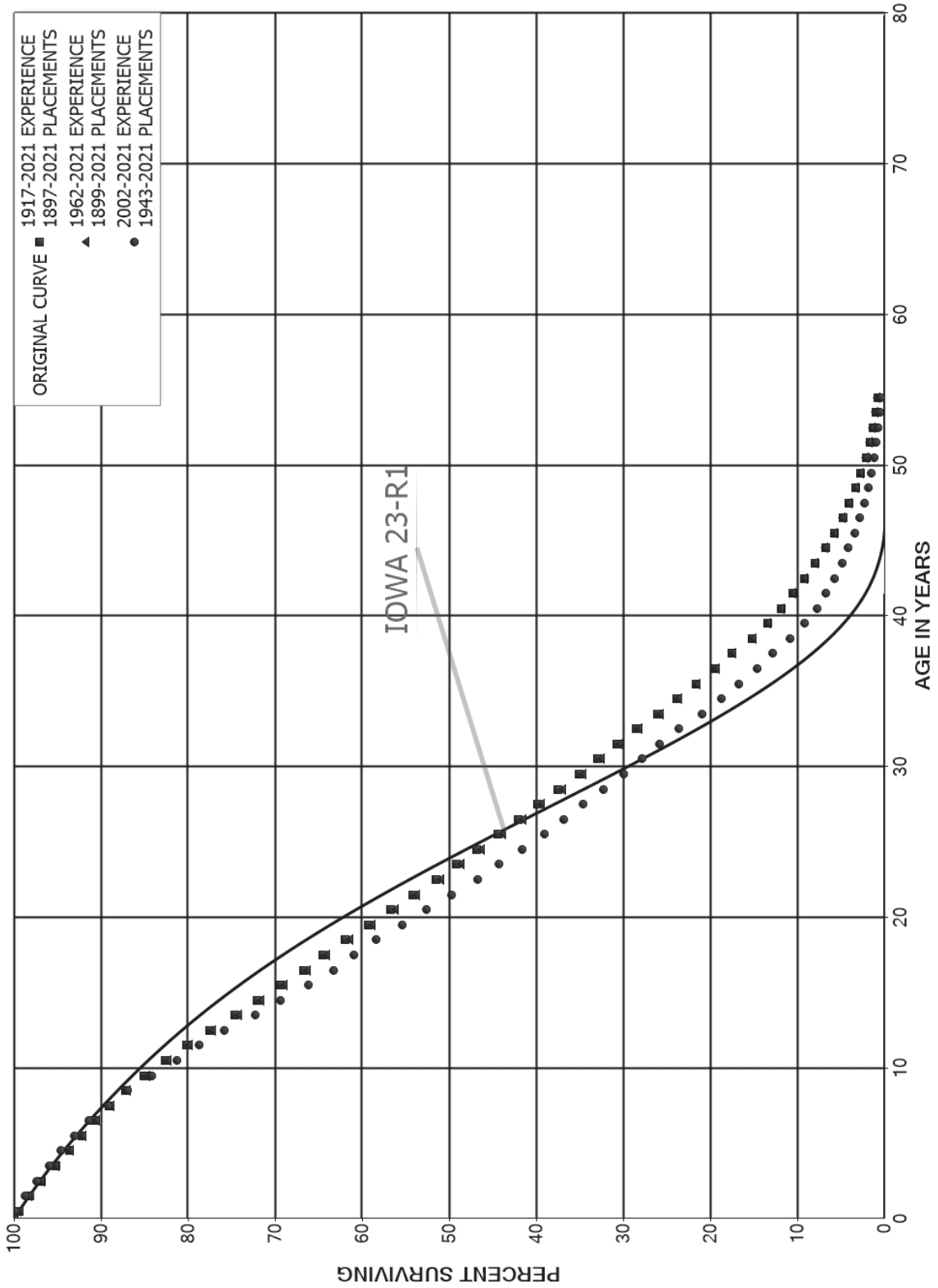
ACCOUNT 369.00 SERVICES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1900-2021 EXPERIENCE BAND 2002-2021

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	77,907	1,691	0.0217	0.9783	56.94
80.5	48,690	19	0.0004	0.9996	55.71
81.5	25,120	27	0.0011	0.9989	55.68
82.5	23,540		0.0000	1.0000	55.62
83.5	19,851		0.0000	1.0000	55.62
84.5	14,059		0.0000	1.0000	55.62
85.5	9,136		0.0000	1.0000	55.62
86.5	4,825		0.0000	1.0000	55.62
87.5	3,683		0.0000	1.0000	55.62
88.5	2,568		0.0000	1.0000	55.62
89.5	2,002		0.0000	1.0000	55.62
90.5	1,342		0.0000	1.0000	55.62
91.5	573		0.0000	1.0000	55.62
92.5	336		0.0000	1.0000	55.62
93.5	264		0.0000	1.0000	55.62
94.5	169		0.0000	1.0000	55.62
95.5					55.62
96.5					
97.5					
98.5					
99.5					
100.5					
101.5	882,925		0.0000		
102.5	882,925		0.0000		
103.5	882,925		0.0000		
104.5	882,925		0.0000		
105.5	882,925		0.0000		
106.5	882,925		0.0000		
107.5	882,925		0.0000		
108.5	882,925		0.0000		
109.5	882,925	412,568	0.4673		
110.5	470,357	470,357	1.0000		
111.5					

JERSEY CENTRAL POWER & LIGHT COMPANY
ACCOUNT 370.00 METERS
ORIGINAL AND SMOOTH SURVIVOR CURVES



JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 370.00 METERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1897-2021 EXPERIENCE BAND 1917-2021

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	318,364,313	1,869,533	0.0059	0.9941	100.00
0.5	302,137,078	3,707,748	0.0123	0.9877	99.41
1.5	287,681,994	4,013,322	0.0140	0.9860	98.19
2.5	269,682,060	4,617,388	0.0171	0.9829	96.82
3.5	237,199,613	3,887,927	0.0164	0.9836	95.17
4.5	220,678,343	3,394,786	0.0154	0.9846	93.61
5.5	204,443,754	3,310,878	0.0162	0.9838	92.17
6.5	184,848,405	3,359,766	0.0182	0.9818	90.67
7.5	172,107,634	3,511,748	0.0204	0.9796	89.02
8.5	153,613,184	3,830,005	0.0249	0.9751	87.21
9.5	150,017,804	4,197,619	0.0280	0.9720	85.03
10.5	141,301,310	4,194,999	0.0297	0.9703	82.65
11.5	130,333,574	4,297,236	0.0330	0.9670	80.20
12.5	119,985,911	4,607,956	0.0384	0.9616	77.56
13.5	110,417,581	3,710,591	0.0336	0.9664	74.58
14.5	105,580,657	3,925,113	0.0372	0.9628	72.07
15.5	98,415,799	3,764,184	0.0382	0.9618	69.39
16.5	91,408,469	3,100,526	0.0339	0.9661	66.74
17.5	84,892,649	3,367,646	0.0397	0.9603	64.47
18.5	77,873,136	3,301,546	0.0424	0.9576	61.92
19.5	72,617,064	3,155,549	0.0435	0.9565	59.29
20.5	67,245,028	2,981,663	0.0443	0.9557	56.72
21.5	62,863,088	3,101,747	0.0493	0.9507	54.20
22.5	58,650,501	2,675,993	0.0456	0.9544	51.53
23.5	54,227,855	2,635,302	0.0486	0.9514	49.18
24.5	50,291,350	2,592,643	0.0516	0.9484	46.79
25.5	47,048,060	2,431,183	0.0517	0.9483	44.37
26.5	43,498,972	2,266,875	0.0521	0.9479	42.08
27.5	40,016,451	2,424,194	0.0606	0.9394	39.89
28.5	36,731,904	2,334,795	0.0636	0.9364	37.47
29.5	33,473,705	2,075,146	0.0620	0.9380	35.09
30.5	30,398,544	2,023,462	0.0666	0.9334	32.91
31.5	27,927,296	2,025,945	0.0725	0.9275	30.72
32.5	25,098,543	2,149,516	0.0856	0.9144	28.49
33.5	22,256,166	1,898,543	0.0853	0.9147	26.05
34.5	19,773,206	1,806,649	0.0914	0.9086	23.83
35.5	17,213,712	1,769,604	0.1028	0.8972	21.65
36.5	14,958,479	1,504,422	0.1006	0.8994	19.43
37.5	13,018,660	1,702,376	0.1308	0.8692	17.47
38.5	10,599,265	1,214,109	0.1145	0.8855	15.19

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 370.00 METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1897-2021 EXPERIENCE BAND 1917-2021

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	9,428,359	1,136,384	0.1205	0.8795	13.45
40.5	8,487,023	960,288	0.1131	0.8869	11.83
41.5	7,571,042	968,837	0.1280	0.8720	10.49
42.5	6,748,952	896,061	0.1328	0.8672	9.15
43.5	6,018,582	877,822	0.1459	0.8541	7.93
44.5	5,390,800	857,483	0.1591	0.8409	6.78
45.5	4,636,107	784,681	0.1693	0.8307	5.70
46.5	3,910,616	586,860	0.1501	0.8499	4.73
47.5	3,420,582	646,868	0.1891	0.8109	4.02
48.5	2,785,949	501,449	0.1800	0.8200	3.26
49.5	2,294,673	493,478	0.2151	0.7849	2.68
50.5	1,971,155	446,446	0.2265	0.7735	2.10
51.5	1,582,110	336,158	0.2125	0.7875	1.62
52.5	1,270,336	295,319	0.2325	0.7675	1.28
53.5	987,963	224,441	0.2272	0.7728	0.98
54.5	768,506	197,213	0.2566	0.7434	0.76
55.5	575,299	161,545	0.2808	0.7192	0.56
56.5	496,885	154,016	0.3100	0.6900	0.41
57.5	334,739	109,674	0.3276	0.6724	0.28
58.5	279,964	54,739	0.1955	0.8045	0.19
59.5	232,943	33,311	0.1430	0.8570	0.15
60.5	193,926	60,578	0.3124	0.6876	0.13
61.5	133,822	82,439	0.6160	0.3840	0.09
62.5	51,329	9,305	0.1813	0.8187	0.03
63.5	40,497	2,706	0.0668	0.9332	0.03
64.5	37,539	409	0.0109	0.9891	0.03
65.5	34,878	325	0.0093	0.9907	0.03
66.5	30,109	423	0.0140	0.9860	0.03
67.5	24,167	753	0.0311	0.9689	0.03
68.5	20,593	114	0.0055	0.9945	0.02
69.5	19,727	912	0.0462	0.9538	0.02
70.5	18,617	274	0.0147	0.9853	0.02
71.5	17,845	27	0.0015	0.9985	0.02
72.5	17,446	95	0.0054	0.9946	0.02
73.5	17,296	240	0.0139	0.9861	0.02
74.5	16,777	0	0.0000	1.0000	0.02
75.5	16,520		0.0000	1.0000	0.02
76.5	16,520	7	0.0004	0.9996	0.02
77.5	16,572		0.0000	1.0000	0.02
78.5	16,594		0.0000	1.0000	0.02

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 370.00 METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1897-2021 EXPERIENCE BAND 1917-2021

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	16,628		0.0000	1.0000	0.02
80.5	16,742		0.0000	1.0000	0.02
81.5	16,719		0.0000	1.0000	0.02
82.5	16,700	29	0.0017	0.9983	0.02
83.5	16,821	11	0.0006	0.9994	0.02
84.5	16,796		0.0000	1.0000	0.02
85.5	16,796	14,106	0.8398	0.1602	0.02
86.5	2,555	23	0.0088	0.9912	0.00
87.5	40,554	11,339	0.2796	0.7204	0.00
88.5	27,905	13,276	0.4758	0.5242	0.00
89.5	14,629		0.0000	1.0000	0.00
90.5	66,332	4,038	0.0609	0.9391	0.00
91.5	62,294	9,416	0.1512	0.8488	0.00
92.5	52,877	2,832	0.0536	0.9464	0.00
93.5	50,045	12,707	0.2539	0.7461	0.00
94.5	37,338	15,605	0.4180	0.5820	0.00
95.5	21,732	11,706	0.5386	0.4614	0.00
96.5	3,795	3,795	1.0000		0.00
97.5					

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 370.00 METERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1899-2021 EXPERIENCE BAND 1962-2021

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	308,156,195	1,868,357	0.0061	0.9939	100.00
0.5	292,502,250	3,700,946	0.0127	0.9873	99.39
1.5	278,555,460	4,003,211	0.0144	0.9856	98.14
2.5	261,236,353	4,607,717	0.0176	0.9824	96.73
3.5	229,391,568	3,872,699	0.0169	0.9831	95.02
4.5	213,526,132	3,384,413	0.0159	0.9841	93.42
5.5	197,879,172	3,302,238	0.0167	0.9833	91.93
6.5	179,128,822	3,349,883	0.0187	0.9813	90.40
7.5	167,010,144	3,502,598	0.0210	0.9790	88.71
8.5	149,189,530	3,819,212	0.0256	0.9744	86.85
9.5	146,184,854	4,187,993	0.0286	0.9714	84.63
10.5	138,061,359	4,185,060	0.0303	0.9697	82.20
11.5	127,706,501	4,290,894	0.0336	0.9664	79.71
12.5	117,897,602	4,602,384	0.0390	0.9610	77.03
13.5	108,853,360	3,705,031	0.0340	0.9660	74.02
14.5	104,369,259	3,920,317	0.0376	0.9624	71.51
15.5	97,280,591	3,759,597	0.0386	0.9614	68.82
16.5	90,226,447	3,094,810	0.0343	0.9657	66.16
17.5	83,622,380	3,359,118	0.0402	0.9598	63.89
18.5	76,535,112	3,292,571	0.0430	0.9570	61.32
19.5	71,232,616	3,146,591	0.0442	0.9558	58.69
20.5	65,982,424	2,967,367	0.0450	0.9550	56.09
21.5	61,552,448	3,087,823	0.0502	0.9498	53.57
22.5	57,315,921	2,654,080	0.0463	0.9537	50.88
23.5	52,893,800	2,607,006	0.0493	0.9507	48.53
24.5	48,987,705	2,550,370	0.0521	0.9479	46.14
25.5	45,778,261	2,391,489	0.0522	0.9478	43.73
26.5	42,243,563	2,219,464	0.0525	0.9475	41.45
27.5	38,789,373	2,367,376	0.0610	0.9390	39.27
28.5	35,550,579	2,270,902	0.0639	0.9361	36.87
29.5	32,321,011	2,000,728	0.0619	0.9381	34.52
30.5	29,322,266	1,941,494	0.0662	0.9338	32.38
31.5	26,994,920	1,945,830	0.0721	0.9279	30.24
32.5	24,298,954	2,075,244	0.0854	0.9146	28.06
33.5	21,599,656	1,829,266	0.0847	0.9153	25.66
34.5	19,250,646	1,748,636	0.0908	0.9092	23.49
35.5	16,789,953	1,717,550	0.1023	0.8977	21.36
36.5	14,631,059	1,465,049	0.1001	0.8999	19.17
37.5	12,766,987	1,672,790	0.1310	0.8690	17.25
38.5	10,400,577	1,188,648	0.1143	0.8857	14.99

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 370.00 METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1899-2021 EXPERIENCE BAND 1962-2021

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	9,285,175	1,116,710	0.1203	0.8797	13.28
40.5	8,378,533	947,409	0.1131	0.8869	11.68
41.5	7,492,863	958,740	0.1280	0.8720	10.36
42.5	6,688,650	887,601	0.1327	0.8673	9.03
43.5	5,970,385	870,534	0.1458	0.8542	7.84
44.5	5,355,856	852,050	0.1591	0.8409	6.69
45.5	4,612,796	781,136	0.1693	0.8307	5.63
46.5	3,892,430	583,302	0.1499	0.8501	4.68
47.5	3,407,663	643,742	0.1889	0.8111	3.97
48.5	2,776,195	499,738	0.1800	0.8200	3.22
49.5	2,287,729	490,718	0.2145	0.7855	2.64
50.5	1,947,469	444,384	0.2282	0.7718	2.08
51.5	1,560,466	335,447	0.2150	0.7850	1.60
52.5	1,249,448	295,016	0.2361	0.7639	1.26
53.5	967,483	224,323	0.2319	0.7681	0.96
54.5	748,308	196,918	0.2632	0.7368	0.74
55.5	555,417	161,312	0.2904	0.7096	0.54
56.5	477,266	153,620	0.3219	0.6781	0.39
57.5	315,515	108,838	0.3450	0.6550	0.26
58.5	261,575	54,107	0.2069	0.7931	0.17
59.5	215,186	32,019	0.1488	0.8512	0.14
60.5	177,461	60,578	0.3414	0.6586	0.12
61.5	133,822	82,439	0.6160	0.3840	0.08
62.5	51,329	9,305	0.1813	0.8187	0.03
63.5	40,497	2,706	0.0668	0.9332	0.02
64.5	37,539	409	0.0109	0.9891	0.02
65.5	34,878	325	0.0093	0.9907	0.02
66.5	30,109	423	0.0140	0.9860	0.02
67.5	24,167	753	0.0311	0.9689	0.02
68.5	20,593	114	0.0055	0.9945	0.02
69.5	19,727	912	0.0462	0.9538	0.02
70.5	18,617	274	0.0147	0.9853	0.02
71.5	17,845	27	0.0015	0.9985	0.02
72.5	17,446	95	0.0054	0.9946	0.02
73.5	17,296	240	0.0139	0.9861	0.02
74.5	16,777	0	0.0000	1.0000	0.02
75.5	16,520		0.0000	1.0000	0.02
76.5	16,520	7	0.0004	0.9996	0.02
77.5	16,572		0.0000	1.0000	0.02
78.5	16,594		0.0000	1.0000	0.02

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 370.00 METERS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1899-2021 EXPERIENCE BAND 1962-2021

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	16,628		0.0000	1.0000	0.02
80.5	16,742		0.0000	1.0000	0.02
81.5	16,719		0.0000	1.0000	0.02
82.5	16,700	29	0.0017	0.9983	0.02
83.5	16,821	11	0.0006	0.9994	0.02
84.5	16,796		0.0000	1.0000	0.02
85.5	16,796	14,106	0.8398	0.1602	0.02
86.5	2,555	23	0.0088	0.9912	0.00
87.5	40,554	11,339	0.2796	0.7204	0.00
88.5	27,905	13,276	0.4758	0.5242	0.00
89.5	14,629		0.0000	1.0000	0.00
90.5	66,332	4,038	0.0609	0.9391	0.00
91.5	62,294	9,416	0.1512	0.8488	0.00
92.5	52,877	2,832	0.0536	0.9464	0.00
93.5	50,045	12,707	0.2539	0.7461	0.00
94.5	37,338	15,605	0.4180	0.5820	0.00
95.5	21,732	11,706	0.5386	0.4614	0.00
96.5	3,795	3,795	1.0000		0.00
97.5					

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 370.00 METERS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1943-2021 EXPERIENCE BAND 2002-2021

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	190,703,147	415,346	0.0022	0.9978	100.00
0.5	180,998,064	1,831,303	0.0101	0.9899	99.78
1.5	172,572,836	2,315,961	0.0134	0.9866	98.77
2.5	160,081,383	2,419,480	0.0151	0.9849	97.45
3.5	142,152,031	2,053,674	0.0144	0.9856	95.97
4.5	129,750,343	2,049,505	0.0158	0.9842	94.59
5.5	116,472,864	2,192,335	0.0188	0.9812	93.09
6.5	101,773,466	2,412,062	0.0237	0.9763	91.34
7.5	93,971,494	2,349,607	0.0250	0.9750	89.18
8.5	80,496,992	2,570,962	0.0319	0.9681	86.95
9.5	78,023,369	2,653,625	0.0340	0.9660	84.17
10.5	73,634,485	2,350,388	0.0319	0.9681	81.31
11.5	66,467,066	2,448,993	0.0368	0.9632	78.71
12.5	60,549,748	2,802,671	0.0463	0.9537	75.81
13.5	54,897,836	2,242,482	0.0408	0.9592	72.30
14.5	54,332,742	2,480,501	0.0457	0.9543	69.35
15.5	52,388,490	2,317,139	0.0442	0.9558	66.18
16.5	49,019,338	1,797,863	0.0367	0.9633	63.26
17.5	45,905,727	1,953,549	0.0426	0.9574	60.94
18.5	42,560,784	2,116,203	0.0497	0.9503	58.34
19.5	39,809,877	2,048,522	0.0515	0.9485	55.44
20.5	36,324,011	1,961,231	0.0540	0.9460	52.59
21.5	33,675,652	2,014,950	0.0598	0.9402	49.75
22.5	31,228,186	1,687,664	0.0540	0.9460	46.77
23.5	28,397,514	1,698,283	0.0598	0.9402	44.25
24.5	26,046,132	1,612,393	0.0619	0.9381	41.60
25.5	24,095,439	1,383,384	0.0574	0.9426	39.02
26.5	21,714,420	1,258,173	0.0579	0.9421	36.78
27.5	19,564,440	1,311,012	0.0670	0.9330	34.65
28.5	18,213,466	1,366,020	0.0750	0.9250	32.33
29.5	16,559,328	1,146,005	0.0692	0.9308	29.91
30.5	14,938,275	1,075,120	0.0720	0.9280	27.84
31.5	13,750,743	1,184,292	0.0861	0.9139	25.83
32.5	12,229,036	1,350,551	0.1104	0.8896	23.61
33.5	10,771,180	1,140,359	0.1059	0.8941	21.00
34.5	9,499,346	1,033,236	0.1088	0.8912	18.78
35.5	8,080,241	1,025,449	0.1269	0.8731	16.73
36.5	7,095,467	878,958	0.1239	0.8761	14.61
37.5	6,194,348	958,563	0.1547	0.8453	12.80
38.5	4,876,833	734,007	0.1505	0.8495	10.82

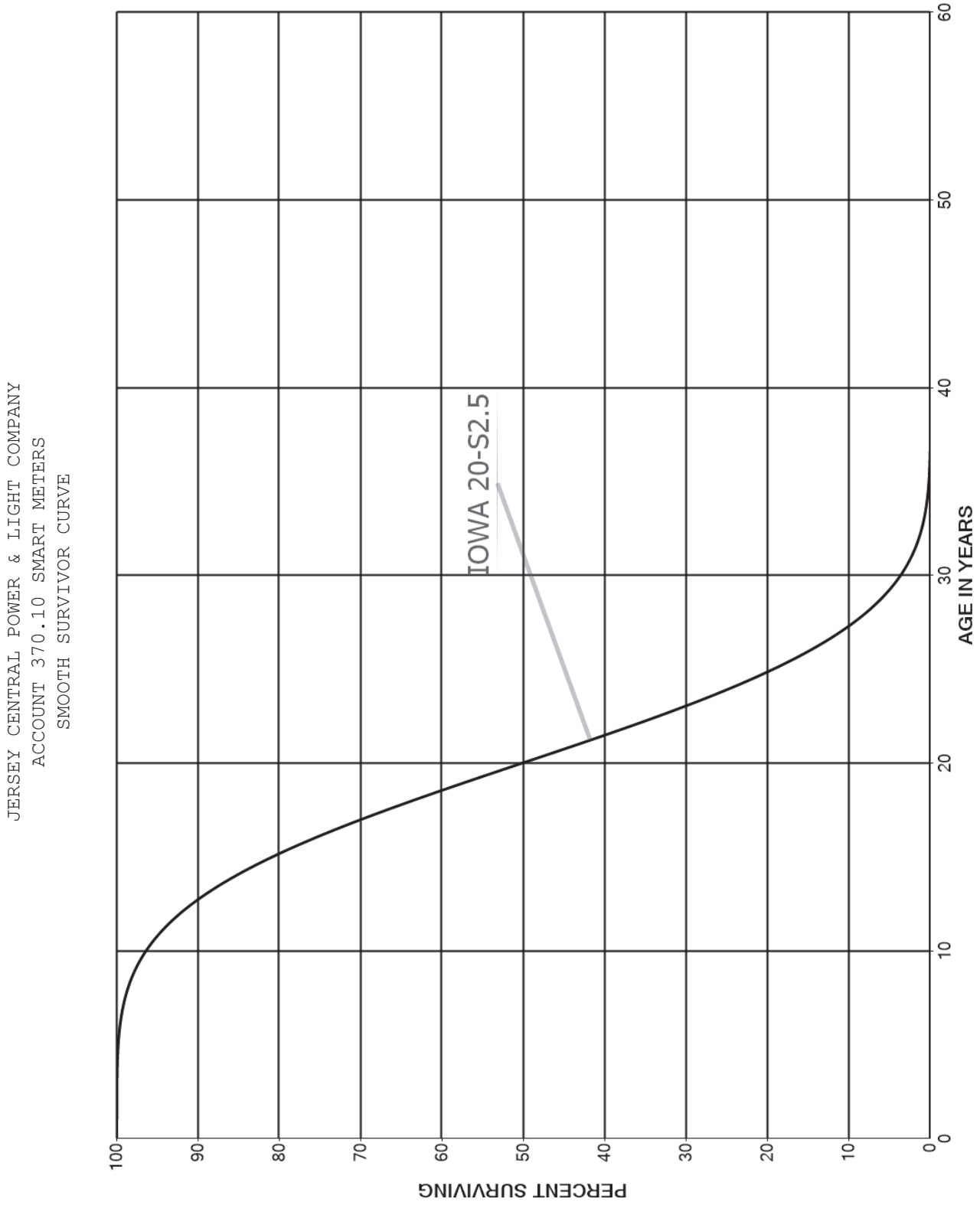
JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 370.00 METERS

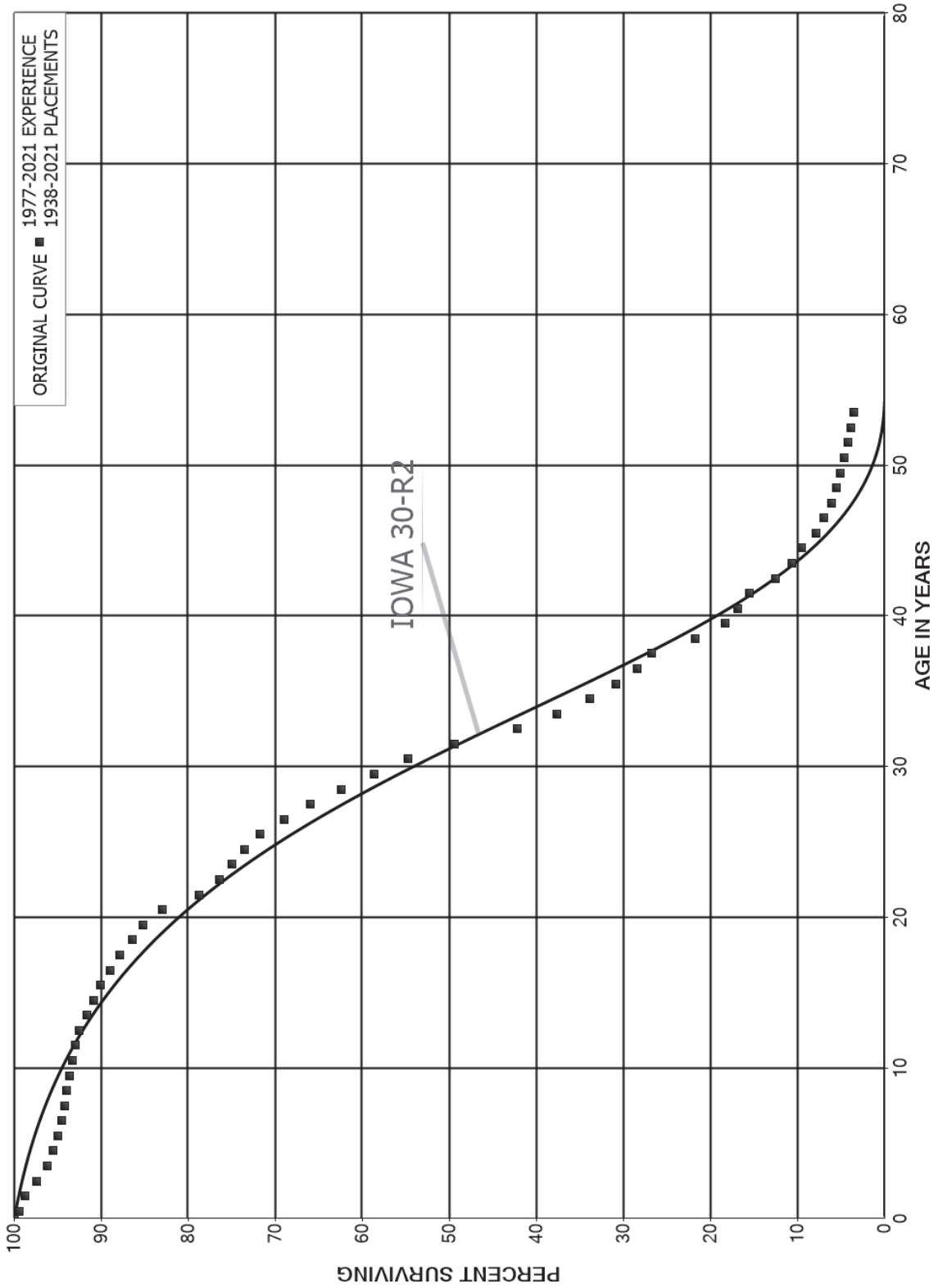
ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1943-2021 EXPERIENCE BAND 2002-2021

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	4,500,858	695,595	0.1545	0.8455	9.19
40.5	4,195,372	580,677	0.1384	0.8616	7.77
41.5	3,963,572	578,360	0.1459	0.8541	6.70
42.5	3,671,397	536,659	0.1462	0.8538	5.72
43.5	3,377,786	506,145	0.1498	0.8502	4.88
44.5	3,129,341	543,994	0.1738	0.8262	4.15
45.5	2,834,732	504,355	0.1779	0.8221	3.43
46.5	2,587,530	453,978	0.1754	0.8246	2.82
47.5	2,283,581	434,268	0.1902	0.8098	2.32
48.5	1,918,310	383,105	0.1997	0.8003	1.88
49.5	1,594,460	364,004	0.2283	0.7717	1.51
50.5	1,357,197	312,526	0.2303	0.7697	1.16
51.5	1,127,510	269,830	0.2393	0.7607	0.89
52.5	932,318	235,576	0.2527	0.7473	0.68
53.5	747,830	199,555	0.2668	0.7332	0.51
54.5	570,240	175,180	0.3072	0.6928	0.37
55.5	407,447	144,852	0.3555	0.6445	0.26
56.5	269,452	121,337	0.4503	0.5497	0.17
57.5	151,687	79,445	0.5237	0.4763	0.09
58.5	158,548	42,459	0.2678	0.7322	0.04
59.5	116,088	19,699	0.1697	0.8303	0.03
60.5	96,389	8,250	0.0856	0.9144	0.03
61.5	88,139	74,748	0.8481	0.1519	0.02
62.5	13,390	8,587	0.6413	0.3587	0.00
63.5	4,803	2,616	0.5446	0.4554	0.00
64.5	2,187	333	0.1521	0.8479	0.00
65.5	1,855	12	0.0062	0.9938	0.00
66.5	1,843	305	0.1656	0.8344	0.00
67.5	1,538	697	0.4535	0.5465	0.00
68.5	840		0.0000	1.0000	0.00
69.5	840	840	1.0000		0.00
70.5					


JERSEY CENTRAL POWER & LIGHT COMPANY
ACCOUNT 370.10 SMART METERS
SMOOTH SURVIVOR CURVE
IOWA 20-S2.5
PERCENT SURVIVING
100
90
80
70
60
50
40
30
20
10
0
AGE IN YEARS
0
10
20
30
40
50
60

JERSEY CENTRAL POWER & LIGHT COMPANY
ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES
ORIGINAL AND SMOOTH SURVIVOR CURVES



JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES

ORIGINAL LIFE TABLE

PLACEMENT BAND 1938-2021 EXPERIENCE BAND 1977-2021

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	51,909,403	315,859	0.0061	0.9939	100.00
0.5	50,930,766	331,627	0.0065	0.9935	99.39
1.5	27,910,266	367,467	0.0132	0.9868	98.74
2.5	26,076,341	353,981	0.0136	0.9864	97.44
3.5	26,099,617	169,800	0.0065	0.9935	96.12
4.5	27,718,280	160,541	0.0058	0.9942	95.50
5.5	28,303,536	127,123	0.0045	0.9955	94.94
6.5	27,871,575	91,460	0.0033	0.9967	94.52
7.5	27,355,018	83,025	0.0030	0.9970	94.21
8.5	26,720,676	85,222	0.0032	0.9968	93.92
9.5	25,754,262	87,176	0.0034	0.9966	93.62
10.5	25,132,566	87,514	0.0035	0.9965	93.30
11.5	24,256,852	113,870	0.0047	0.9953	92.98
12.5	23,108,695	241,873	0.0105	0.9895	92.54
13.5	21,820,886	180,404	0.0083	0.9917	91.57
14.5	21,177,032	165,016	0.0078	0.9922	90.82
15.5	20,055,428	251,534	0.0125	0.9875	90.11
16.5	18,824,638	247,208	0.0131	0.9869	88.98
17.5	17,660,035	275,255	0.0156	0.9844	87.81
18.5	17,046,119	245,093	0.0144	0.9856	86.44
19.5	16,633,471	448,254	0.0269	0.9731	85.20
20.5	15,936,547	806,475	0.0506	0.9494	82.90
21.5	15,047,362	447,589	0.0297	0.9703	78.71
22.5	14,460,659	276,718	0.0191	0.9809	76.37
23.5	12,875,510	243,740	0.0189	0.9811	74.91
24.5	11,532,237	280,608	0.0243	0.9757	73.49
25.5	7,936,394	303,686	0.0383	0.9617	71.70
26.5	4,875,312	209,166	0.0429	0.9571	68.96
27.5	2,813,448	152,933	0.0544	0.9456	66.00
28.5	1,834,369	111,684	0.0609	0.9391	62.41
29.5	1,286,135	84,521	0.0657	0.9343	58.61
30.5	1,132,839	111,897	0.0988	0.9012	54.76
31.5	903,969	131,036	0.1450	0.8550	49.35
32.5	686,788	74,207	0.1080	0.8920	42.20
33.5	603,489	60,189	0.0997	0.9003	37.64
34.5	510,400	46,553	0.0912	0.9088	33.88
35.5	439,116	34,091	0.0776	0.9224	30.79
36.5	394,556	23,259	0.0590	0.9410	28.40
37.5	345,276	65,180	0.1888	0.8112	26.73
38.5	269,429	42,610	0.1582	0.8418	21.68

JERSEY CENTRAL POWER & LIGHT COMPANY

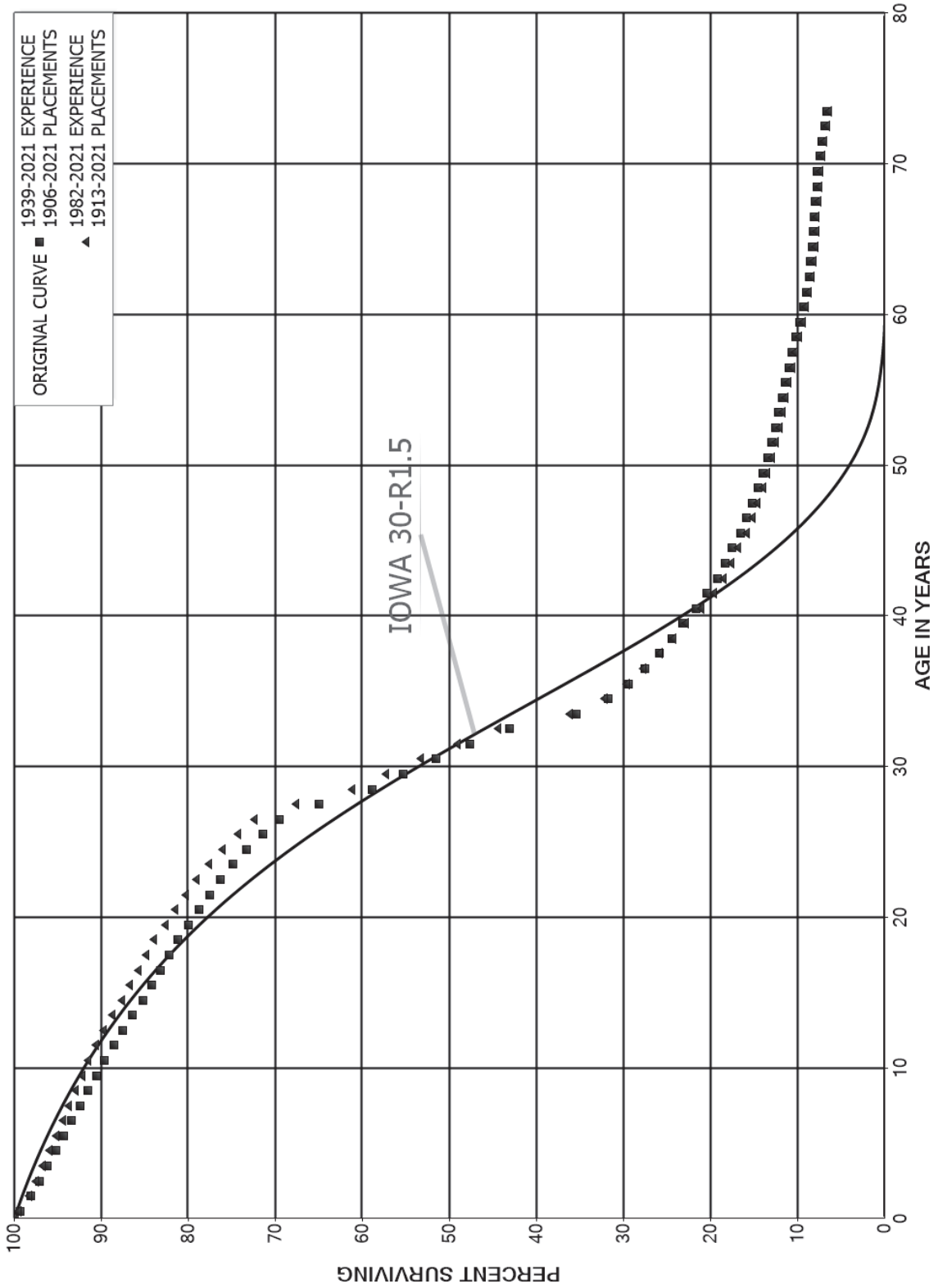
ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1938-2021 EXPERIENCE BAND 1977-2021

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	226,819	17,797	0.0785	0.9215	18.25
40.5	209,021	16,875	0.0807	0.9193	16.82
41.5	192,147	36,462	0.1898	0.8102	15.46
42.5	155,752	23,686	0.1521	0.8479	12.53
43.5	132,066	13,880	0.1051	0.8949	10.62
44.5	118,186	20,591	0.1742	0.8258	9.51
45.5	97,594	10,678	0.1094	0.8906	7.85
46.5	86,916	11,859	0.1364	0.8636	6.99
47.5	75,057	6,710	0.0894	0.9106	6.04
48.5	68,348	5,764	0.0843	0.9157	5.50
49.5	62,583	4,902	0.0783	0.9217	5.03
50.5	57,681	5,125	0.0889	0.9111	4.64
51.5	52,556	4,321	0.0822	0.9178	4.23
52.5	48,234	5,115	0.1060	0.8940	3.88
53.5	1,015	765	0.7540	0.2460	3.47
54.5	250	37	0.1486	0.8514	0.85
55.5	213	20	0.0924	0.9076	0.73
56.5	193	15	0.0802	0.9198	0.66
57.5	177	20	0.1134	0.8866	0.61
58.5	157		0.0000	1.0000	0.54
59.5	157	5	0.0317	0.9683	0.54
60.5	152	139	0.9092	0.0908	0.52
61.5	14		0.0000	1.0000	0.05
62.5	14	5	0.3591	0.6409	0.05
63.5	9	9	1.0000		0.03
64.5					

JERSEY CENTRAL POWER & LIGHT COMPANY
ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS
ORIGINAL AND SMOOTH SURVIVOR CURVES



JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1906-2021 EXPERIENCE BAND 1939-2021

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	347,866,173	2,322,896	0.0067	0.9933	100.00
0.5	326,352,886	4,205,008	0.0129	0.9871	99.33
1.5	304,338,577	3,073,212	0.0101	0.9899	98.05
2.5	287,241,108	2,786,118	0.0097	0.9903	97.06
3.5	259,607,072	2,467,766	0.0095	0.9905	96.12
4.5	254,146,349	2,489,715	0.0098	0.9902	95.21
5.5	245,963,388	2,437,027	0.0099	0.9901	94.27
6.5	233,442,111	2,333,732	0.0100	0.9900	93.34
7.5	220,778,671	2,257,958	0.0102	0.9898	92.41
8.5	209,133,810	2,111,126	0.0101	0.9899	91.46
9.5	189,645,654	2,012,215	0.0106	0.9894	90.54
10.5	179,956,126	2,082,030	0.0116	0.9884	89.58
11.5	168,285,278	1,975,423	0.0117	0.9883	88.54
12.5	158,524,530	1,997,996	0.0126	0.9874	87.50
13.5	148,274,728	2,071,954	0.0140	0.9860	86.40
14.5	139,357,988	1,714,107	0.0123	0.9877	85.19
15.5	129,187,362	1,502,346	0.0116	0.9884	84.14
16.5	118,419,843	1,467,339	0.0124	0.9876	83.17
17.5	110,924,548	1,280,772	0.0115	0.9885	82.14
18.5	105,202,655	1,645,371	0.0156	0.9844	81.19
19.5	99,593,394	1,479,722	0.0149	0.9851	79.92
20.5	86,234,977	1,294,290	0.0150	0.9850	78.73
21.5	79,835,038	1,341,526	0.0168	0.9832	77.55
22.5	72,259,504	1,312,373	0.0182	0.9818	76.25
23.5	68,505,394	1,461,352	0.0213	0.9787	74.86
24.5	63,644,990	1,611,074	0.0253	0.9747	73.26
25.5	59,196,139	1,601,940	0.0271	0.9729	71.41
26.5	55,300,499	3,588,988	0.0649	0.9351	69.48
27.5	49,404,034	4,642,337	0.0940	0.9060	64.97
28.5	41,938,530	2,578,711	0.0615	0.9385	58.86
29.5	37,508,725	2,532,904	0.0675	0.9325	55.24
30.5	33,097,917	2,511,256	0.0759	0.9241	51.51
31.5	28,973,706	2,753,088	0.0950	0.9050	47.60
32.5	24,188,901	4,300,172	0.1778	0.8222	43.08
33.5	17,361,682	1,799,453	0.1036	0.8964	35.42
34.5	13,432,369	1,011,494	0.0753	0.9247	31.75
35.5	10,461,269	666,706	0.0637	0.9363	29.36
36.5	8,742,891	538,687	0.0616	0.9384	27.49
37.5	7,612,990	399,460	0.0525	0.9475	25.80
38.5	6,710,553	346,874	0.0517	0.9483	24.44

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1906-2021 EXPERIENCE BAND 1939-2021

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	6,042,765	415,592	0.0688	0.9312	23.18
40.5	5,458,730	296,526	0.0543	0.9457	21.58
41.5	5,139,830	301,403	0.0586	0.9414	20.41
42.5	4,871,891	234,430	0.0481	0.9519	19.21
43.5	4,750,132	215,157	0.0453	0.9547	18.29
44.5	4,582,783	255,010	0.0556	0.9444	17.46
45.5	4,352,333	180,703	0.0415	0.9585	16.49
46.5	4,024,577	174,058	0.0432	0.9568	15.81
47.5	3,786,401	159,179	0.0420	0.9580	15.12
48.5	3,506,737	121,466	0.0346	0.9654	14.49
49.5	3,243,974	134,760	0.0415	0.9585	13.98
50.5	3,042,110	105,360	0.0346	0.9654	13.40
51.5	2,849,590	88,935	0.0312	0.9688	12.94
52.5	2,694,895	71,430	0.0265	0.9735	12.54
53.5	2,538,333	89,063	0.0351	0.9649	12.20
54.5	2,409,242	73,294	0.0304	0.9696	11.77
55.5	2,301,798	83,798	0.0364	0.9636	11.42
56.5	2,397,381	79,368	0.0331	0.9669	11.00
57.5	2,265,356	93,793	0.0414	0.9586	10.64
58.5	2,120,747	93,451	0.0441	0.9559	10.20
59.5	2,003,608	84,602	0.0422	0.9578	9.75
60.5	1,902,650	71,722	0.0377	0.9623	9.34
61.5	1,798,497	63,425	0.0353	0.9647	8.98
62.5	1,675,878	38,649	0.0231	0.9769	8.67
63.5	1,602,311	43,779	0.0273	0.9727	8.47
64.5	1,493,736	18,724	0.0125	0.9875	8.24
65.5	1,437,518	11,407	0.0079	0.9921	8.13
66.5	1,402,340	29,104	0.0208	0.9792	8.07
67.5	1,354,579	27,653	0.0204	0.9796	7.90
68.5	1,305,420	10,136	0.0078	0.9922	7.74
69.5	1,289,238	50,420	0.0391	0.9609	7.68
70.5	1,227,984	38,926	0.0317	0.9683	7.38
71.5	1,184,854	44,512	0.0376	0.9624	7.14
72.5	1,133,355	40,222	0.0355	0.9645	6.88
73.5	152,754	24,146	0.1581	0.8419	6.63
74.5	127,668	18,742	0.1468	0.8532	5.58
75.5	107,340	10,446	0.0973	0.9027	4.76
76.5	90,702	5,596	0.0617	0.9383	4.30
77.5	84,222	6,795	0.0807	0.9193	4.04
78.5	8,874		0.0000	1.0000	3.71

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1906-2021 EXPERIENCE BAND 1939-2021

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	8,874		0.0000	1.0000	3.71
80.5	8,874		0.0000	1.0000	3.71
81.5	8,874	12	0.0013	0.9987	3.71
82.5	8,863	3	0.0003	0.9997	3.70
83.5	8,860		0.0000	1.0000	3.70
84.5	6,410	278	0.0433	0.9567	3.70
85.5	6,132	6,132	1.0000		3.54
86.5					

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1913-2021 EXPERIENCE BAND 1982-2021

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	309,318,603	2,013,369	0.0065	0.9935	100.00
0.5	290,183,536	3,347,391	0.0115	0.9885	99.35
1.5	271,433,060	2,322,142	0.0086	0.9914	98.20
2.5	257,002,325	2,056,162	0.0080	0.9920	97.36
3.5	231,453,126	1,754,284	0.0076	0.9924	96.58
4.5	227,900,522	1,805,245	0.0079	0.9921	95.85
5.5	221,859,435	1,773,505	0.0080	0.9920	95.09
6.5	211,369,408	1,625,217	0.0077	0.9923	94.33
7.5	201,092,609	1,615,702	0.0080	0.9920	93.61
8.5	191,620,656	1,539,802	0.0080	0.9920	92.86
9.5	174,115,005	1,435,564	0.0082	0.9918	92.11
10.5	165,895,476	1,560,954	0.0094	0.9906	91.35
11.5	155,513,783	1,518,361	0.0098	0.9902	90.49
12.5	147,059,776	1,600,339	0.0109	0.9891	89.61
13.5	138,067,612	1,736,955	0.0126	0.9874	88.63
14.5	130,098,553	1,418,245	0.0109	0.9891	87.52
15.5	120,777,892	1,265,021	0.0105	0.9895	86.56
16.5	110,833,805	1,275,305	0.0115	0.9885	85.66
17.5	104,226,044	1,091,508	0.0105	0.9895	84.67
18.5	99,454,708	1,473,738	0.0148	0.9852	83.78
19.5	94,478,961	1,328,778	0.0141	0.9859	82.54
20.5	81,612,451	1,175,957	0.0144	0.9856	81.38
21.5	75,632,036	1,237,584	0.0164	0.9836	80.21
22.5	68,370,400	1,222,401	0.0179	0.9821	78.90
23.5	64,860,788	1,307,693	0.0202	0.9798	77.49
24.5	60,421,627	1,412,152	0.0234	0.9766	75.92
25.5	56,354,378	1,454,218	0.0258	0.9742	74.15
26.5	52,722,093	3,441,856	0.0653	0.9347	72.24
27.5	47,072,656	4,537,424	0.0964	0.9036	67.52
28.5	39,713,378	2,530,035	0.0637	0.9363	61.01
29.5	35,290,005	2,468,812	0.0700	0.9300	57.12
30.5	30,948,777	2,420,619	0.0782	0.9218	53.13
31.5	26,910,919	2,550,856	0.0948	0.9052	48.97
32.5	22,348,890	4,191,276	0.1875	0.8125	44.33
33.5	15,634,505	1,721,563	0.1101	0.8899	36.02
34.5	11,780,176	931,444	0.0791	0.9209	32.05
35.5	8,887,919	583,175	0.0656	0.9344	29.52
36.5	7,258,493	476,630	0.0657	0.9343	27.58
37.5	6,193,242	370,867	0.0599	0.9401	25.77
38.5	5,311,290	322,276	0.0607	0.9393	24.23

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1913-2021 EXPERIENCE BAND 1982-2021

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	4,671,554	380,869	0.0815	0.9185	22.76
40.5	4,147,021	267,751	0.0646	0.9354	20.90
41.5	4,873,920	293,175	0.0602	0.9398	19.55
42.5	4,640,844	221,168	0.0477	0.9523	18.38
43.5	4,546,908	202,356	0.0445	0.9555	17.50
44.5	4,414,100	252,464	0.0572	0.9428	16.72
45.5	4,196,013	175,633	0.0419	0.9581	15.76
46.5	3,895,998	166,320	0.0427	0.9573	15.10
47.5	3,666,251	151,148	0.0412	0.9588	14.46
48.5	3,394,920	119,290	0.0351	0.9649	13.86
49.5	3,154,173	132,991	0.0422	0.9578	13.38
50.5	2,977,845	105,081	0.0353	0.9647	12.81
51.5	2,794,218	87,887	0.0315	0.9685	12.36
52.5	2,676,810	70,371	0.0263	0.9737	11.97
53.5	2,523,868	89,009	0.0353	0.9647	11.66
54.5	2,395,245	73,215	0.0306	0.9694	11.25
55.5	2,287,306	83,798	0.0366	0.9634	10.90
56.5	2,385,547	79,368	0.0333	0.9667	10.50
57.5	2,253,522	93,392	0.0414	0.9586	10.15
58.5	2,109,367	93,114	0.0441	0.9559	9.73
59.5	1,992,565	84,602	0.0425	0.9575	9.30
60.5	1,892,938	71,722	0.0379	0.9621	8.91
61.5	1,788,785	63,413	0.0355	0.9645	8.57
62.5	1,666,919	38,649	0.0232	0.9768	8.27
63.5	1,593,353	43,698	0.0274	0.9726	8.07
64.5	1,484,870	18,720	0.0126	0.9874	7.85
65.5	1,428,655	11,407	0.0080	0.9920	7.75
66.5	1,393,477	29,104	0.0209	0.9791	7.69
67.5	1,345,997	27,653	0.0205	0.9795	7.53
68.5	1,305,420	10,136	0.0078	0.9922	7.38
69.5	1,289,238	50,420	0.0391	0.9609	7.32
70.5	1,227,984	38,926	0.0317	0.9683	7.03
71.5	1,184,854	44,512	0.0376	0.9624	6.81
72.5	1,133,355	40,222	0.0355	0.9645	6.55
73.5	152,754	24,146	0.1581	0.8419	6.32
74.5	127,668	18,742	0.1468	0.8532	5.32
75.5	107,340	10,446	0.0973	0.9027	4.54
76.5	90,702	5,596	0.0617	0.9383	4.10
77.5	84,222	6,795	0.0807	0.9193	3.85
78.5	8,874		0.0000	1.0000	3.54

JERSEY CENTRAL POWER & LIGHT COMPANY

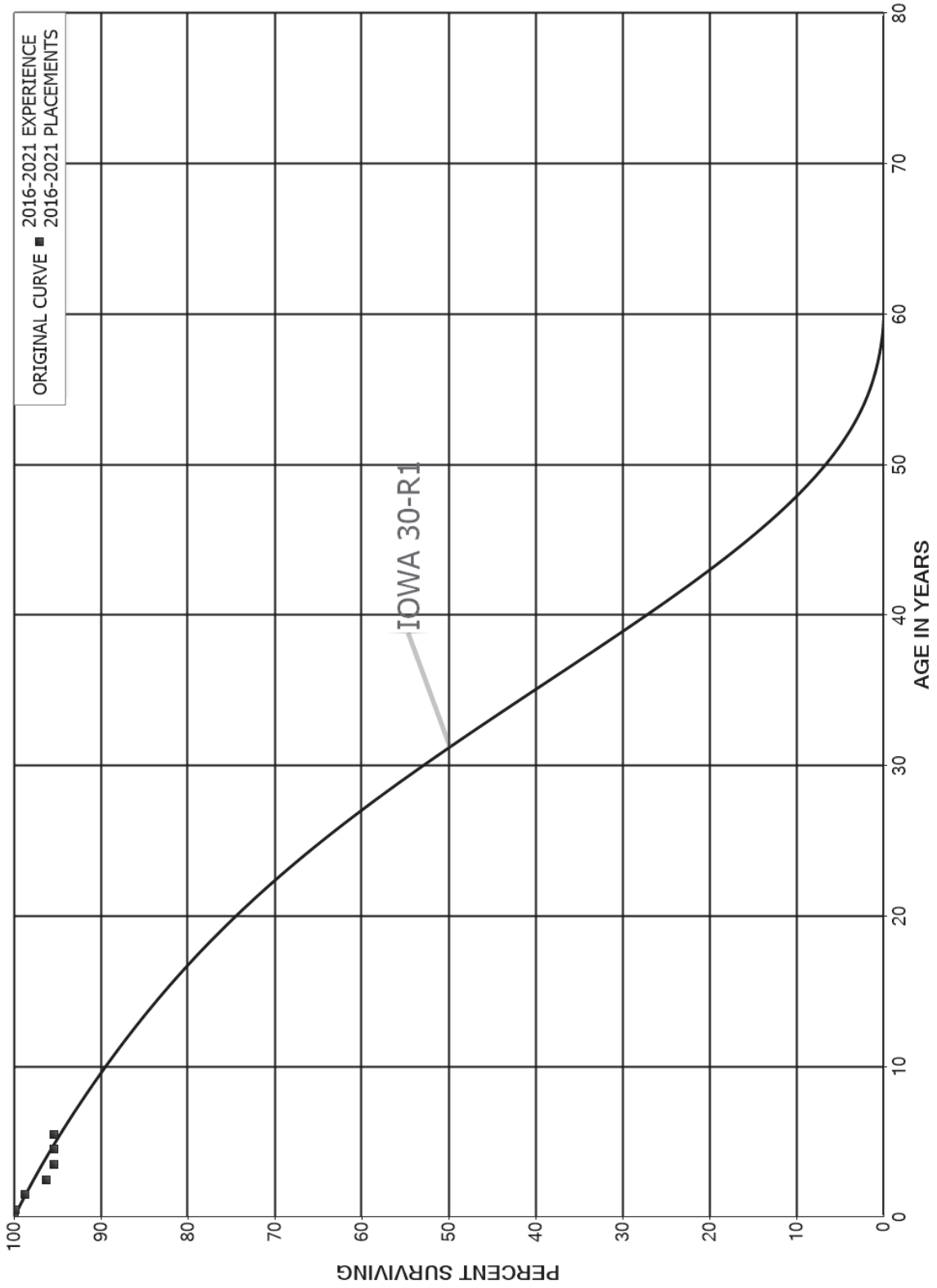
ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1913-2021 EXPERIENCE BAND 1982-2021

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	8,874		0.0000	1.0000	3.54
80.5	8,874		0.0000	1.0000	3.54
81.5	8,874	12	0.0013	0.9987	3.54
82.5	8,863	3	0.0003	0.9997	3.53
83.5	8,860		0.0000	1.0000	3.53
84.5	6,410	278	0.0433	0.9567	3.53
85.5	6,132	6,132	1.0000		3.38
86.5					

JERSEY CENTRAL POWER & LIGHT COMPANY
ACCOUNT 373.30 STREET LIGHTING AND SIGNAL SYSTEMS - LED
ORIGINAL AND SMOOTH SURVIVOR CURVES



JERSEY CENTRAL POWER & LIGHT COMPANY

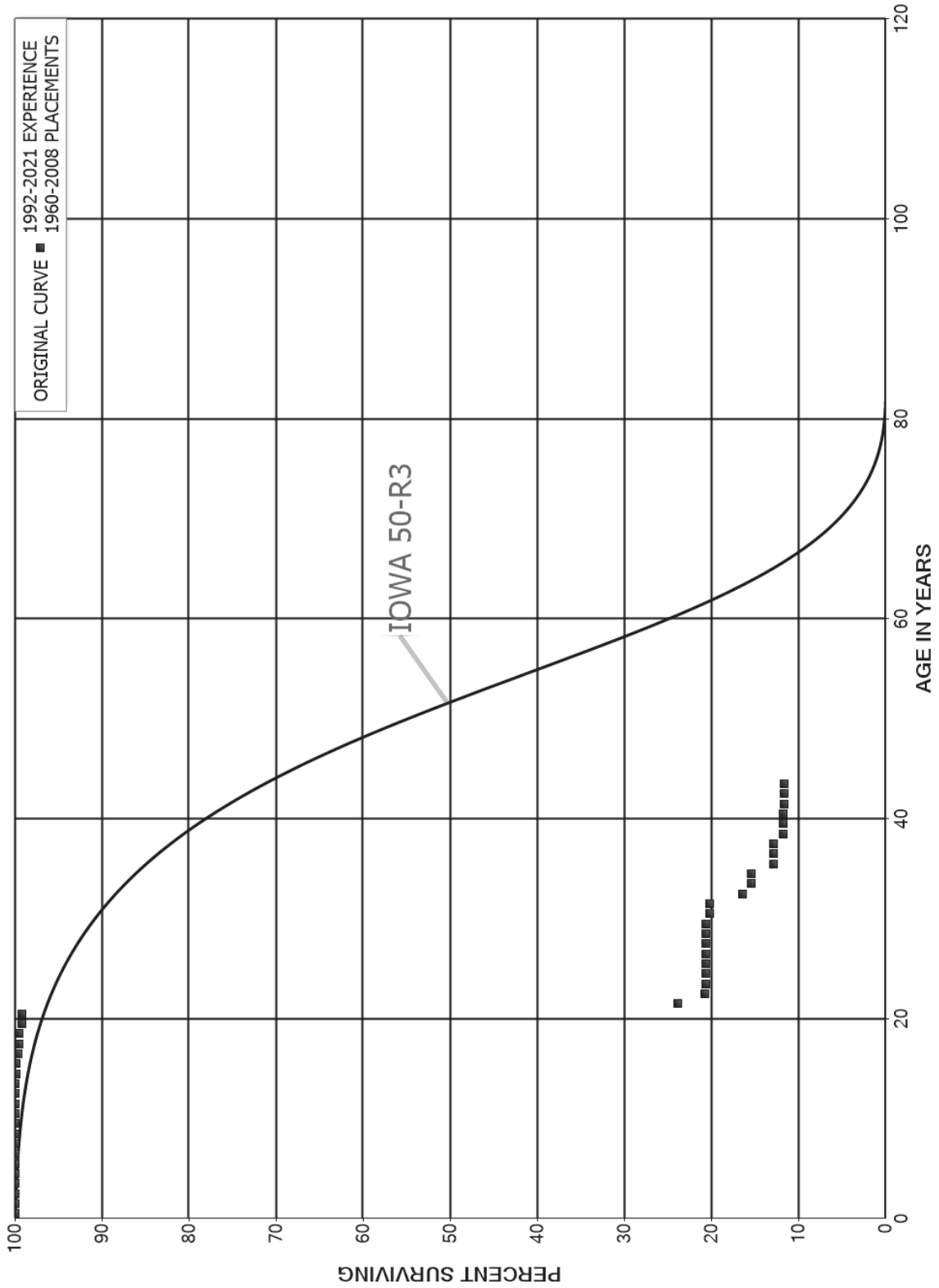
ACCOUNT 373.30 STREET LIGHTING AND SIGNAL SYSTEMS - LED

ORIGINAL LIFE TABLE

PLACEMENT BAND 2016-2021 EXPERIENCE BAND 2016-2021

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	2,243,218	3,432	0.0015	0.9985	100.00
0.5	1,196,855	13,175	0.0110	0.9890	99.85
1.5	644,531	16,387	0.0254	0.9746	98.75
2.5	273,844	2,476	0.0090	0.9910	96.24
3.5	55,936		0.0000	1.0000	95.37
4.5	2,010		0.0000	1.0000	95.37
5.5					95.37

JERSEY CENTRAL POWER & LIGHT COMPANY
ACCOUNT 389.20 LAND RIGHTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 389.20 LAND RIGHTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1960-2008 EXPERIENCE BAND 1992-2021

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	87,034		0.0000	1.0000	100.00
0.5	87,034		0.0000	1.0000	100.00
1.5	87,034		0.0000	1.0000	100.00
2.5	87,034		0.0000	1.0000	100.00
3.5	87,034		0.0000	1.0000	100.00
4.5	87,034	81	0.0009	0.9991	100.00
5.5	86,953	14	0.0002	0.9998	99.91
6.5	86,939		0.0000	1.0000	99.89
7.5	86,939		0.0000	1.0000	99.89
8.5	88,799		0.0000	1.0000	99.89
9.5	88,799		0.0000	1.0000	99.89
10.5	93,565		0.0000	1.0000	99.89
11.5	93,565		0.0000	1.0000	99.89
12.5	93,565		0.0000	1.0000	99.89
13.5	97,095	18	0.0002	0.9998	99.89
14.5	97,077	1	0.0000	1.0000	99.87
15.5	103,602	257	0.0025	0.9975	99.87
16.5	116,886	102	0.0009	0.9991	99.62
17.5	116,783	4	0.0000	1.0000	99.54
18.5	116,779	441	0.0038	0.9962	99.53
19.5	116,338	15	0.0001	0.9999	99.16
20.5	116,324	88,356	0.7596	0.2404	99.14
21.5	27,968	3,676	0.1314	0.8686	23.84
22.5	24,292	81	0.0033	0.9967	20.70
23.5	24,211		0.0000	1.0000	20.64
24.5	24,211		0.0000	1.0000	20.64
25.5	24,211		0.0000	1.0000	20.64
26.5	24,211		0.0000	1.0000	20.64
27.5	24,211		0.0000	1.0000	20.64
28.5	24,211		0.0000	1.0000	20.64
29.5	24,211	526	0.0217	0.9783	20.64
30.5	23,685		0.0000	1.0000	20.19
31.5	23,685	4,497	0.1899	0.8101	20.19
32.5	19,697	1,221	0.0620	0.9380	16.35
33.5	18,476		0.0000	1.0000	15.34
34.5	18,481	3,075	0.1664	0.8336	15.34
35.5	15,406		0.0000	1.0000	12.79
36.5	15,406	0	0.0000	1.0000	12.79
37.5	15,406	1,253	0.0813	0.9187	12.79
38.5	14,153		0.0000	1.0000	11.75

JERSEY CENTRAL POWER & LIGHT COMPANY

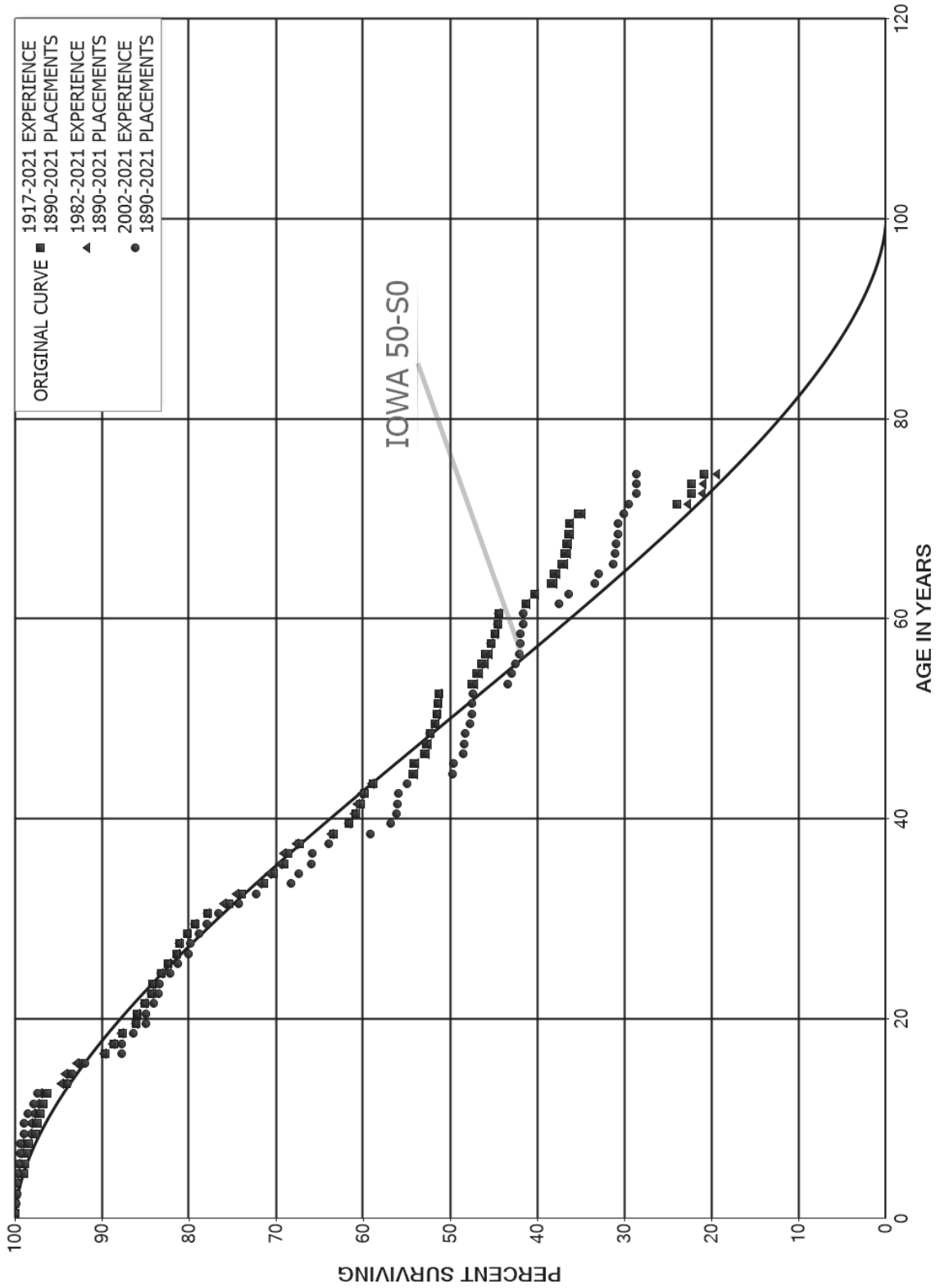
ACCOUNT 389.20 LAND RIGHTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1960-2008 EXPERIENCE BAND 1992-2021

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	14,153	5	0.0004	0.9996	11.75
40.5	14,148	94	0.0067	0.9933	11.74
41.5	14,054		0.0000	1.0000	11.67
42.5	8,981		0.0000	1.0000	11.67
43.5					11.67

JERSEY CENTRAL POWER & LIGHT COMPANY
ACCOUNT 390.10 STRUCTURES AND IMPROVEMENTS
ORIGINAL AND SMOOTH SURVIVOR CURVES



JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 390.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1890-2021 EXPERIENCE BAND 1917-2021

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	157,460,119	65,133	0.0004	0.9996	100.00
0.5	148,976,318	83,207	0.0006	0.9994	99.96
1.5	149,895,517	41,237	0.0003	0.9997	99.90
2.5	147,097,544	168,778	0.0011	0.9989	99.88
3.5	140,502,461	1,068,168	0.0076	0.9924	99.76
4.5	135,271,777	189,796	0.0014	0.9986	99.00
5.5	130,032,188	324,057	0.0025	0.9975	98.86
6.5	126,445,499	325,584	0.0026	0.9974	98.62
7.5	122,447,843	961,701	0.0079	0.9921	98.36
8.5	120,388,707	208,404	0.0017	0.9983	97.59
9.5	116,444,609	375,058	0.0032	0.9968	97.42
10.5	114,501,153	515,441	0.0045	0.9955	97.11
11.5	112,957,515	443,035	0.0039	0.9961	96.67
12.5	109,096,745	2,534,071	0.0232	0.9768	96.29
13.5	100,741,318	450,776	0.0045	0.9955	94.05
14.5	99,023,912	1,276,748	0.0129	0.9871	93.63
15.5	95,284,974	2,880,841	0.0302	0.9698	92.43
16.5	91,848,493	1,006,086	0.0110	0.9890	89.63
17.5	90,103,734	1,012,352	0.0112	0.9888	88.65
18.5	85,718,576	1,555,578	0.0181	0.9819	87.65
19.5	83,495,988	168,604	0.0020	0.9980	86.06
20.5	81,208,467	758,748	0.0093	0.9907	85.89
21.5	77,637,335	693,940	0.0089	0.9911	85.09
22.5	73,907,503	168,016	0.0023	0.9977	84.33
23.5	68,055,328	767,019	0.0113	0.9887	84.14
24.5	66,011,453	621,064	0.0094	0.9906	83.19
25.5	64,479,510	817,659	0.0127	0.9873	82.40
26.5	61,603,602	199,743	0.0032	0.9968	81.36
27.5	60,495,294	716,005	0.0118	0.9882	81.10
28.5	58,221,081	650,732	0.0112	0.9888	80.14
29.5	52,741,100	958,632	0.0182	0.9818	79.24
30.5	48,351,723	1,491,024	0.0308	0.9692	77.80
31.5	36,707,254	687,987	0.0187	0.9813	75.40
32.5	34,964,486	1,225,981	0.0351	0.9649	73.99
33.5	32,756,624	495,134	0.0151	0.9849	71.39
34.5	29,746,186	510,911	0.0172	0.9828	70.31
35.5	27,500,965	179,431	0.0065	0.9935	69.11
36.5	25,083,676	519,926	0.0207	0.9793	68.66
37.5	23,318,420	1,312,617	0.0563	0.9437	67.23
38.5	19,038,908	556,452	0.0292	0.9708	63.45

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 390.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1890-2021 EXPERIENCE BAND 1917-2021

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	18,489,007	241,030	0.0130	0.9870	61.59
40.5	17,708,344	143,204	0.0081	0.9919	60.79
41.5	17,689,054	150,302	0.0085	0.9915	60.30
42.5	15,793,450	263,186	0.0167	0.9833	59.79
43.5	14,675,705	1,114,024	0.0759	0.9241	58.79
44.5	13,394,323	28,957	0.0022	0.9978	54.33
45.5	13,276,915	307,830	0.0232	0.9768	54.21
46.5	12,962,388	47,706	0.0037	0.9963	52.95
47.5	12,536,432	100,236	0.0080	0.9920	52.76
48.5	12,304,104	154,913	0.0126	0.9874	52.34
49.5	12,124,140	47,257	0.0039	0.9961	51.68
50.5	12,116,938	25,805	0.0021	0.9979	51.48
51.5	11,363,885	16,796	0.0015	0.9985	51.37
52.5	10,958,616	815,992	0.0745	0.9255	51.29
53.5	10,104,668	102,215	0.0101	0.9899	47.47
54.5	9,165,776	123,839	0.0135	0.9865	46.99
55.5	7,332,897	65,833	0.0090	0.9910	46.36
56.5	6,730,740	96,760	0.0144	0.9856	45.94
57.5	6,227,782	67,850	0.0109	0.9891	45.28
58.5	6,003,552	38,726	0.0065	0.9935	44.79
59.5	5,056,818	8,524	0.0017	0.9983	44.50
60.5	4,699,202	333,340	0.0709	0.9291	44.42
61.5	3,625,739	85,507	0.0236	0.9764	41.27
62.5	3,049,605	142,730	0.0468	0.9532	40.30
63.5	2,385,368	22,766	0.0095	0.9905	38.41
64.5	2,239,572	48,159	0.0215	0.9785	38.05
65.5	1,995,544	22,045	0.0110	0.9890	37.23
66.5	1,917,449	12,774	0.0067	0.9933	36.82
67.5	1,569,119	6,930	0.0044	0.9956	36.57
68.5	1,354,073	2,941	0.0022	0.9978	36.41
69.5	1,395,117	41,548	0.0298	0.9702	36.33
70.5	1,229,000	395,776	0.3220	0.6780	35.25
71.5	834,149	55,178	0.0661	0.9339	23.90
72.5	780,636	2,834	0.0036	0.9964	22.32
73.5	805,973	50,108	0.0622	0.9378	22.24
74.5	743,921	26,029	0.0350	0.9650	20.85
75.5	672,731	2,664	0.0040	0.9960	20.12
76.5	667,546	1,773	0.0027	0.9973	20.04
77.5	664,723	2,739	0.0041	0.9959	19.99
78.5	656,324	1,907	0.0029	0.9971	19.91

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 390.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1890-2021 EXPERIENCE BAND 1917-2021

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	635,011	11,805	0.0186	0.9814	19.85
80.5	618,916	9,208	0.0149	0.9851	19.48
81.5	608,039		0.0000	1.0000	19.19
82.5	603,696	0	0.0000	1.0000	19.19
83.5	602,859	45	0.0001	0.9999	19.19
84.5	602,814	3,532	0.0059	0.9941	19.19
85.5	595,040	6,565	0.0110	0.9890	19.08
86.5	586,826	2,446	0.0042	0.9958	18.87
87.5	584,380	16,749	0.0287	0.9713	18.79
88.5	567,631	158,024	0.2784	0.7216	18.25
89.5	408,749	0	0.0000	1.0000	13.17
90.5	399,771	139,691	0.3494	0.6506	13.17
91.5	257,061	8,580	0.0334	0.9666	8.57
92.5	238,943	43,784	0.1832	0.8168	8.28
93.5	194,126	64,670	0.3331	0.6669	6.76
94.5	124,642	1,324	0.0106	0.9894	4.51
95.5	123,318		0.0000	1.0000	4.46
96.5	123,184	4,334	0.0352	0.9648	4.46
97.5	116,868	28	0.0002	0.9998	4.31
98.5	115,869	2,594	0.0224	0.9776	4.30
99.5	112,921		0.0000	1.0000	4.21
100.5	112,921		0.0000	1.0000	4.21
101.5	112,921		0.0000	1.0000	4.21
102.5	112,921		0.0000	1.0000	4.21
103.5	112,921		0.0000	1.0000	4.21
104.5	112,921		0.0000	1.0000	4.21
105.5	112,921		0.0000	1.0000	4.21
106.5	112,921		0.0000	1.0000	4.21
107.5	112,921	40,712	0.3605	0.6395	4.21
108.5	72,209		0.0000	1.0000	2.69
109.5	72,209		0.0000	1.0000	2.69
110.5	66,467		0.0000	1.0000	2.69
111.5	62,263		0.0000	1.0000	2.69
112.5	62,263		0.0000	1.0000	2.69
113.5	62,263		0.0000	1.0000	2.69
114.5	62,263		0.0000	1.0000	2.69
115.5	62,263		0.0000	1.0000	2.69
116.5	62,263	16,136	0.2592	0.7408	2.69
117.5	46,127		0.0000	1.0000	1.99
118.5	46,127		0.0000	1.0000	1.99

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 390.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1890-2021 EXPERIENCE BAND 1917-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
119.5	37,267		0.0000	1.0000	1.99
120.5	37,267		0.0000	1.0000	1.99
121.5	37,267		0.0000	1.0000	1.99
122.5	37,267	18,776	0.5038	0.4962	1.99
123.5	18,490		0.0000	1.0000	0.99
124.5	18,490	1,319	0.0713	0.9287	0.99
125.5	14,807		0.0000	1.0000	0.92
126.5	14,807		0.0000	1.0000	0.92
127.5	14,807		0.0000	1.0000	0.92
128.5	14,807	14,807	1.0000		0.92
129.5					

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 390.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1890-2021 EXPERIENCE BAND 1982-2021

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	135,204,671	12,183	0.0001	0.9999	100.00
0.5	126,180,917	79,108	0.0006	0.9994	99.99
1.5	125,573,017	19,820	0.0002	0.9998	99.93
2.5	123,962,826	40,322	0.0003	0.9997	99.91
3.5	119,357,043	123,509	0.0010	0.9990	99.88
4.5	115,282,600	145,928	0.0013	0.9987	99.78
5.5	110,280,232	284,655	0.0026	0.9974	99.65
6.5	106,981,776	267,449	0.0025	0.9975	99.39
7.5	103,595,530	871,603	0.0084	0.9916	99.14
8.5	101,978,413	119,763	0.0012	0.9988	98.31
9.5	98,656,930	322,247	0.0033	0.9967	98.20
10.5	96,875,377	438,475	0.0045	0.9955	97.87
11.5	96,434,463	359,604	0.0037	0.9963	97.43
12.5	93,461,504	2,396,935	0.0256	0.9744	97.07
13.5	86,417,757	367,997	0.0043	0.9957	94.58
14.5	85,984,827	1,242,904	0.0145	0.9855	94.18
15.5	84,674,331	2,844,021	0.0336	0.9664	92.81
16.5	82,436,982	934,553	0.0113	0.9887	89.70
17.5	81,987,875	921,610	0.0112	0.9888	88.68
18.5	77,819,945	1,476,161	0.0190	0.9810	87.68
19.5	76,467,580	143,111	0.0019	0.9981	86.02
20.5	74,820,580	730,541	0.0098	0.9902	85.86
21.5	72,002,764	647,821	0.0090	0.9910	85.02
22.5	69,845,665	119,488	0.0017	0.9983	84.26
23.5	64,647,533	755,276	0.0117	0.9883	84.11
24.5	62,873,255	598,073	0.0095	0.9905	83.13
25.5	61,914,917	787,291	0.0127	0.9873	82.34
26.5	59,130,611	188,174	0.0032	0.9968	81.29
27.5	58,391,966	699,615	0.0120	0.9880	81.03
28.5	55,910,246	568,317	0.0102	0.9898	80.06
29.5	50,431,063	929,032	0.0184	0.9816	79.25
30.5	46,234,091	1,065,785	0.0231	0.9769	77.79
31.5	35,016,336	683,766	0.0195	0.9805	75.99
32.5	33,249,975	1,214,463	0.0365	0.9635	74.51
33.5	31,082,405	480,580	0.0155	0.9845	71.79
34.5	28,133,168	487,510	0.0173	0.9827	70.68
35.5	25,754,338	137,415	0.0053	0.9947	69.45
36.5	23,366,970	506,267	0.0217	0.9783	69.08
37.5	21,610,324	1,281,768	0.0593	0.9407	67.59
38.5	17,350,930	540,854	0.0312	0.9688	63.58

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 390.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1890-2021 EXPERIENCE BAND 1982-2021

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	16,762,223	180,881	0.0108	0.9892	61.60
40.5	16,047,984	91,346	0.0057	0.9943	60.93
41.5	16,046,089	144,514	0.0090	0.9910	60.59
42.5	14,165,440	258,825	0.0183	0.9817	60.04
43.5	13,113,171	1,104,176	0.0842	0.9158	58.94
44.5	11,728,994	28,105	0.0024	0.9976	53.98
45.5	11,614,725	272,976	0.0235	0.9765	53.85
46.5	11,309,599	44,905	0.0040	0.9960	52.58
47.5	10,885,308	28,644	0.0026	0.9974	52.38
48.5	10,742,227	154,096	0.0143	0.9857	52.24
49.5	10,570,618	29,759	0.0028	0.9972	51.49
50.5	10,582,578	12,881	0.0012	0.9988	51.34
51.5	10,001,374	16,634	0.0017	0.9983	51.28
52.5	9,634,976	782,619	0.0812	0.9188	51.20
53.5	9,121,811	101,215	0.0111	0.9889	47.04
54.5	8,650,686	121,110	0.0140	0.9860	46.52
55.5	6,840,190	65,833	0.0096	0.9904	45.86
56.5	6,341,960	17,502	0.0028	0.9972	45.42
57.5	5,925,372	67,850	0.0115	0.9885	45.30
58.5	5,707,569	38,358	0.0067	0.9933	44.78
59.5	4,767,317	4,583	0.0010	0.9990	44.48
60.5	4,410,546	331,019	0.0751	0.9249	44.43
61.5	3,342,794	85,507	0.0256	0.9744	41.10
62.5	2,768,962	142,680	0.0515	0.9485	40.05
63.5	2,114,460	17,836	0.0084	0.9916	37.99
64.5	1,948,915	48,151	0.0247	0.9753	37.66
65.5	1,704,914	16,682	0.0098	0.9902	36.73
66.5	1,639,557	2,902	0.0018	0.9982	36.37
67.5	1,307,702	6,930	0.0053	0.9947	36.31
68.5	1,094,380	2,941	0.0027	0.9973	36.12
69.5	1,151,906	41,548	0.0361	0.9639	36.02
70.5	1,098,364	382,042	0.3478	0.6522	34.72
71.5	720,833	55,178	0.0765	0.9235	22.64
72.5	667,349	2,834	0.0042	0.9958	20.91
73.5	699,173	50,108	0.0717	0.9283	20.82
74.5	647,115	26,029	0.0402	0.9598	19.33
75.5	575,925	1,464	0.0025	0.9975	18.55
76.5	571,940	1,773	0.0031	0.9969	18.51
77.5	569,117	2,739	0.0048	0.9952	18.45
78.5	560,718	1,907	0.0034	0.9966	18.36

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 390.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1890-2021 EXPERIENCE BAND 1982-2021

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	582,225	1,552	0.0027	0.9973	18.30
80.5	579,004	9,208	0.0159	0.9841	18.25
81.5	568,127		0.0000	1.0000	17.96
82.5	563,784	0	0.0000	1.0000	17.96
83.5	562,947	45	0.0001	0.9999	17.96
84.5	562,901	3,532	0.0063	0.9937	17.96
85.5	580,233	6,565	0.0113	0.9887	17.84
86.5	572,019	2,446	0.0043	0.9957	17.64
87.5	569,573	16,749	0.0294	0.9706	17.57
88.5	552,824	158,024	0.2858	0.7142	17.05
89.5	393,941	0	0.0000	1.0000	12.18
90.5	384,964	139,691	0.3629	0.6371	12.18
91.5	257,061	8,580	0.0334	0.9666	7.76
92.5	238,943	43,784	0.1832	0.8168	7.50
93.5	194,126	64,670	0.3331	0.6669	6.12
94.5	124,642	1,324	0.0106	0.9894	4.08
95.5	123,318		0.0000	1.0000	4.04
96.5	123,184	4,334	0.0352	0.9648	4.04
97.5	116,868	28	0.0002	0.9998	3.90
98.5	115,869	2,594	0.0224	0.9776	3.90
99.5	112,921		0.0000	1.0000	3.81
100.5	112,921		0.0000	1.0000	3.81
101.5	112,921		0.0000	1.0000	3.81
102.5	112,921		0.0000	1.0000	3.81
103.5	112,921		0.0000	1.0000	3.81
104.5	112,921		0.0000	1.0000	3.81
105.5	112,921		0.0000	1.0000	3.81
106.5	112,921		0.0000	1.0000	3.81
107.5	112,921	40,712	0.3605	0.6395	3.81
108.5	72,209		0.0000	1.0000	2.44
109.5	72,209		0.0000	1.0000	2.44
110.5	66,467		0.0000	1.0000	2.44
111.5	62,263		0.0000	1.0000	2.44
112.5	62,263		0.0000	1.0000	2.44
113.5	62,263		0.0000	1.0000	2.44
114.5	62,263		0.0000	1.0000	2.44
115.5	62,263		0.0000	1.0000	2.44
116.5	62,263	16,136	0.2592	0.7408	2.44
117.5	46,127		0.0000	1.0000	1.81
118.5	46,127		0.0000	1.0000	1.81

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 390.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1890-2021 EXPERIENCE BAND 1982-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
119.5	37,267		0.0000	1.0000	1.81
120.5	37,267		0.0000	1.0000	1.81
121.5	37,267		0.0000	1.0000	1.81
122.5	37,267	18,776	0.5038	0.4962	1.81
123.5	18,490		0.0000	1.0000	0.90
124.5	18,490	1,319	0.0713	0.9287	0.90
125.5	14,807		0.0000	1.0000	0.83
126.5	14,807		0.0000	1.0000	0.83
127.5	14,807		0.0000	1.0000	0.83
128.5	14,807	14,807	1.0000		0.83
129.5					

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 390.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE

PLACEMENT BAND 1890-2021 EXPERIENCE BAND 2002-2021

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	31,738,112	20	0.0000	1.0000	100.00
0.5	33,613,795	72,786	0.0022	0.9978	100.00
1.5	35,462,513	10,469	0.0003	0.9997	99.78
2.5	35,751,425	6,015	0.0002	0.9998	99.75
3.5	37,861,880	10,832	0.0003	0.9997	99.74
4.5	37,754,099	42,910	0.0011	0.9989	99.71
5.5	34,337,013	56,952	0.0017	0.9983	99.60
6.5	33,975,927	12,171	0.0004	0.9996	99.43
7.5	34,872,460	153,820	0.0044	0.9956	99.39
8.5	37,935,897	24,854	0.0007	0.9993	98.96
9.5	41,769,750	171,856	0.0041	0.9959	98.89
10.5	46,079,859	314,846	0.0068	0.9932	98.48
11.5	59,584,037	276,340	0.0046	0.9954	97.81
12.5	58,479,467	2,081,558	0.0356	0.9644	97.36
13.5	54,428,171	258,951	0.0048	0.9952	93.89
14.5	58,752,051	910,127	0.0155	0.9845	93.45
15.5	59,924,325	2,751,649	0.0459	0.9541	92.00
16.5	60,830,993	69,172	0.0011	0.9989	87.77
17.5	61,900,707	876,869	0.0142	0.9858	87.67
18.5	60,499,124	1,010,051	0.0167	0.9833	86.43
19.5	59,819,878	62,469	0.0010	0.9990	84.99
20.5	59,754,829	622,447	0.0104	0.9896	84.90
21.5	56,541,590	330,294	0.0058	0.9942	84.02
22.5	55,467,453	80,373	0.0014	0.9986	83.52
23.5	49,571,772	707,972	0.0143	0.9857	83.40
24.5	47,716,976	534,159	0.0112	0.9888	82.21
25.5	46,311,055	689,946	0.0149	0.9851	81.29
26.5	43,660,428	126,787	0.0029	0.9971	80.08
27.5	43,193,939	555,246	0.0129	0.9871	79.85
28.5	40,822,162	479,831	0.0118	0.9882	78.82
29.5	35,565,181	585,917	0.0165	0.9835	77.90
30.5	31,659,597	952,485	0.0301	0.9699	76.61
31.5	21,561,614	572,867	0.0266	0.9734	74.31
32.5	20,436,872	1,146,962	0.0561	0.9439	72.33
33.5	18,840,907	245,941	0.0131	0.9869	68.27
34.5	17,247,631	368,958	0.0214	0.9786	67.38
35.5	17,385,427	29,528	0.0017	0.9983	65.94
36.5	16,007,413	452,819	0.0283	0.9717	65.83
37.5	15,413,546	1,144,667	0.0743	0.9257	63.97
38.5	11,586,929	469,795	0.0405	0.9595	59.22

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 390.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1890-2021 EXPERIENCE BAND 2002-2021

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	11,889,817	137,815	0.0116	0.9884	56.82
40.5	10,890,347	11,713	0.0011	0.9989	56.16
41.5	11,491,532	23,944	0.0021	0.9979	56.10
42.5	11,394,321	205,160	0.0180	0.9820	55.98
43.5	11,211,917	1,068,740	0.0953	0.9047	54.97
44.5	10,333,426	16,924	0.0016	0.9984	49.73
45.5	10,628,573	250,079	0.0235	0.9765	49.65
46.5	10,374,464	12,485	0.0012	0.9988	48.48
47.5	10,325,889	23,584	0.0023	0.9977	48.42
48.5	10,409,409	135,201	0.0130	0.9870	48.31
49.5	10,248,118	27,091	0.0026	0.9974	47.69
50.5	10,335,118	12,609	0.0012	0.9988	47.56
51.5	9,598,622	16,241	0.0017	0.9983	47.50
52.5	9,192,511	777,575	0.0846	0.9154	47.42
53.5	8,385,168	96,286	0.0115	0.9885	43.41
54.5	7,510,414	68,033	0.0091	0.9909	42.91
55.5	5,742,475	58,220	0.0101	0.9899	42.52
56.5	5,154,197	17,102	0.0033	0.9967	42.09
57.5	4,731,161	3,783	0.0008	0.9992	41.95
58.5	4,574,004	32,408	0.0071	0.9929	41.92
59.5	3,634,943	3,232	0.0009	0.9991	41.62
60.5	3,281,438	320,485	0.0977	0.9023	41.58
61.5	2,229,814	66,194	0.0297	0.9703	37.52
62.5	1,694,648	141,453	0.0835	0.9165	36.41
63.5	1,084,593	11,861	0.0109	0.9891	33.37
64.5	935,238	47,273	0.0505	0.9495	33.01
65.5	696,903	7,161	0.0103	0.9897	31.34
66.5	657,417	1,495	0.0023	0.9977	31.01
67.5	337,843	2,017	0.0060	0.9940	30.94
68.5	125,033	179	0.0014	0.9986	30.76
69.5	127,651	2,728	0.0214	0.9786	30.72
70.5	37,417	704	0.0188	0.9812	30.06
71.5	197,992	5,942	0.0300	0.9700	29.49
72.5	210,850		0.0000	1.0000	28.61
73.5	394,496		0.0000	1.0000	28.61
74.5	391,945		0.0000	1.0000	28.61
75.5	381,717		0.0000	1.0000	28.61
76.5	450,983		0.0000	1.0000	28.61
77.5	453,430		0.0000	1.0000	28.61
78.5	451,380	1,656	0.0037	0.9963	28.61

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 390.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1890-2021 EXPERIENCE BAND 2002-2021

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	453,029		0.0000	1.0000	28.50
80.5	450,392	8,379	0.0186	0.9814	28.50
81.5	440,968		0.0000	1.0000	27.97
82.5	436,625		0.0000	1.0000	27.97
83.5	437,385		0.0000	1.0000	27.97
84.5	437,385		0.0000	1.0000	27.97
85.5	435,788		0.0000	1.0000	27.97
86.5	434,139	599	0.0014	0.9986	27.97
87.5	433,540		0.0000	1.0000	27.93
88.5	433,540	157,978	0.3644	0.6356	27.93
89.5	274,703		0.0000	1.0000	17.76
90.5	312,881	139,604	0.4462	0.5538	17.76
91.5	175,495	2,059	0.0117	0.9883	9.83
92.5	163,897	33,883	0.2067	0.7933	9.72
93.5	128,982	64,670	0.5014	0.4986	7.71
94.5	59,498	1,324	0.0223	0.9777	3.84
95.5	58,174		0.0000	1.0000	3.76
96.5	58,040	4,074	0.0702	0.9298	3.76
97.5	51,984		0.0000	1.0000	3.49
98.5	51,013		0.0000	1.0000	3.49
99.5	75,654		0.0000	1.0000	3.49
100.5	75,654		0.0000	1.0000	3.49
101.5	75,654		0.0000	1.0000	3.49
102.5	75,654		0.0000	1.0000	3.49
103.5	75,654		0.0000	1.0000	3.49
104.5	75,654		0.0000	1.0000	3.49
105.5	98,114		0.0000	1.0000	3.49
106.5	98,114		0.0000	1.0000	3.49
107.5	98,114	40,712	0.4149	0.5851	3.49
108.5	57,402		0.0000	1.0000	2.04
109.5	57,402		0.0000	1.0000	2.04
110.5	51,660		0.0000	1.0000	2.04
111.5	62,263		0.0000	1.0000	2.04
112.5	62,263		0.0000	1.0000	2.04
113.5	62,263		0.0000	1.0000	2.04
114.5	62,263		0.0000	1.0000	2.04
115.5	62,263		0.0000	1.0000	2.04
116.5	62,263	16,136	0.2592	0.7408	2.04
117.5	46,127		0.0000	1.0000	1.51
118.5	46,127		0.0000	1.0000	1.51

JERSEY CENTRAL POWER & LIGHT COMPANY

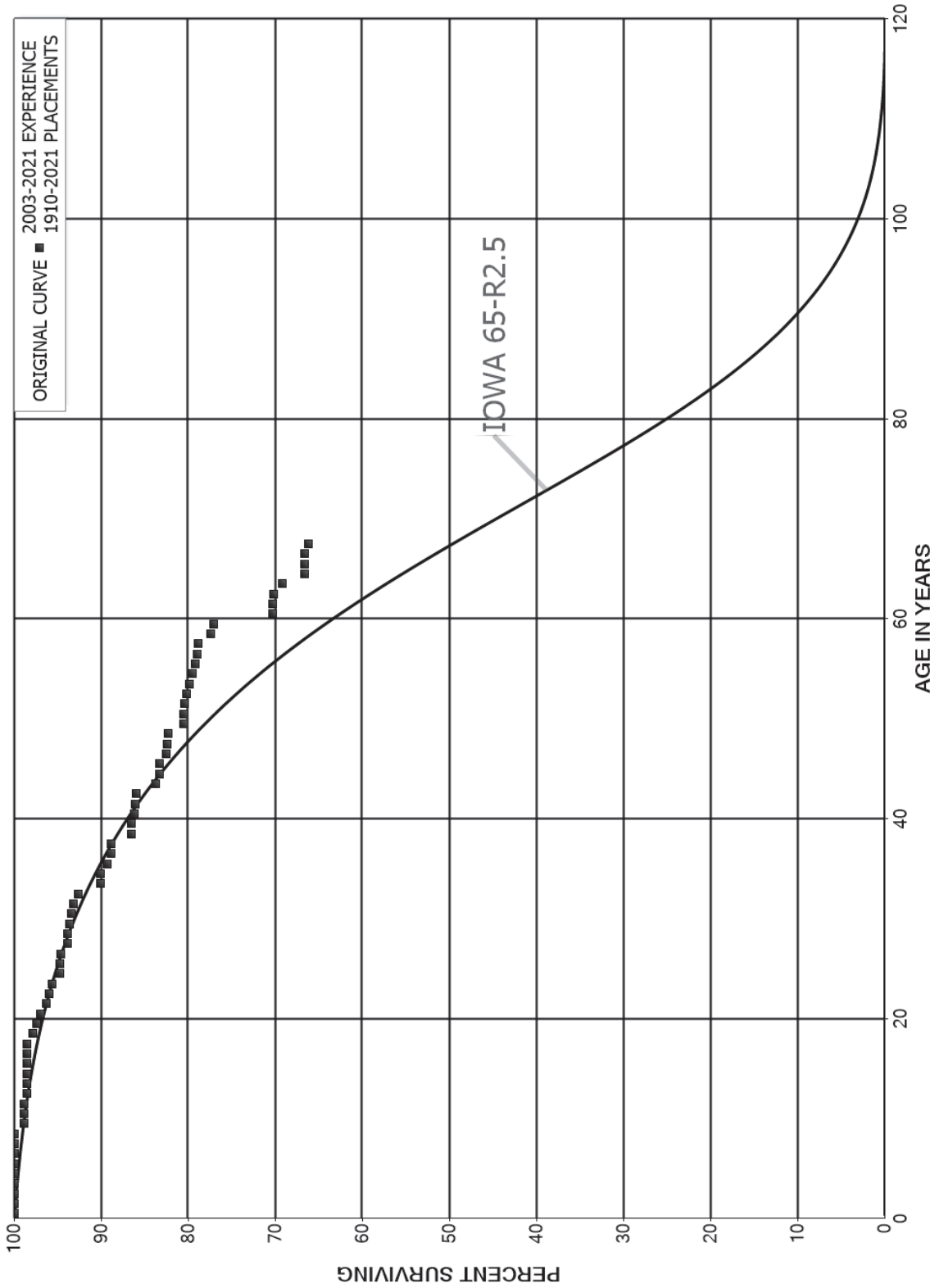
ACCOUNT 390.10 STRUCTURES AND IMPROVEMENTS

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1890-2021 EXPERIENCE BAND 2002-2021

AGE AT BEGIN OF INTERVAL	EXPOSURES AT BEGINNING OF AGE INTERVAL	RETIREMENTS DURING AGE INTERVAL	RETMT RATIO	SURV RATIO	PCT SURV BEGIN OF INTERVAL
119.5	37,267		0.0000	1.0000	1.51
120.5	37,267		0.0000	1.0000	1.51
121.5	37,267		0.0000	1.0000	1.51
122.5	37,267	18,776	0.5038	0.4962	1.51
123.5	18,490		0.0000	1.0000	0.75
124.5	18,490	1,319	0.0713	0.9287	0.75
125.5	14,807		0.0000	1.0000	0.70
126.5	14,807		0.0000	1.0000	0.70
127.5	14,807		0.0000	1.0000	0.70
128.5	14,807	14,807	1.0000		0.70
129.5					

JERSEY CENTRAL POWER & LIGHT COMPANY
ACCOUNT 390.20 STRUCTURES AND IMPROVEMENTS - CLEARING
ORIGINAL AND SMOOTH SURVIVOR CURVES



JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 390.20 STRUCTURES AND IMPROVEMENTS - CLEARING

ORIGINAL LIFE TABLE

PLACEMENT BAND 1910-2021 EXPERIENCE BAND 2003-2021

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	1,021,608		0.0000	1.0000	100.00
0.5	1,095,860		0.0000	1.0000	100.00
1.5	1,242,744		0.0000	1.0000	100.00
2.5	1,286,155		0.0000	1.0000	100.00
3.5	1,627,566		0.0000	1.0000	100.00
4.5	1,801,660		0.0000	1.0000	100.00
5.5	2,275,383		0.0000	1.0000	100.00
6.5	2,801,777		0.0000	1.0000	100.00
7.5	2,916,936		0.0000	1.0000	100.00
8.5	3,311,543	39,530	0.0119	0.9881	100.00
9.5	3,654,687		0.0000	1.0000	98.81
10.5	3,888,507		0.0000	1.0000	98.81
11.5	4,079,946	13,986	0.0034	0.9966	98.81
12.5	5,239,047		0.0000	1.0000	98.47
13.5	5,600,411		0.0000	1.0000	98.47
14.5	6,100,953		0.0000	1.0000	98.47
15.5	6,968,826		0.0000	1.0000	98.47
16.5	7,222,538		0.0000	1.0000	98.47
17.5	7,845,157	49,462	0.0063	0.9937	98.47
18.5	7,966,175	37,638	0.0047	0.9953	97.85
19.5	8,216,210	34,081	0.0041	0.9959	97.38
20.5	9,442,588	67,218	0.0071	0.9929	96.98
21.5	9,380,211	34,830	0.0037	0.9963	96.29
22.5	9,455,718	33,004	0.0035	0.9965	95.93
23.5	9,108,411	84,333	0.0093	0.9907	95.60
24.5	8,757,807		0.0000	1.0000	94.71
25.5	8,848,522	8,295	0.0009	0.9991	94.71
26.5	8,516,668	66,791	0.0078	0.9922	94.62
27.5	8,082,627		0.0000	1.0000	93.88
28.5	7,792,410	18,416	0.0024	0.9976	93.88
29.5	7,689,519	22,025	0.0029	0.9971	93.66
30.5	6,542,904	13,388	0.0020	0.9980	93.39
31.5	5,541,583	35,947	0.0065	0.9935	93.20
32.5	5,012,855	137,426	0.0274	0.9726	92.60
33.5	4,157,586	139	0.0000	1.0000	90.06
34.5	4,019,804	32,369	0.0081	0.9919	90.05
35.5	3,664,466	18,266	0.0050	0.9950	89.33
36.5	3,551,967	1,474	0.0004	0.9996	88.88
37.5	3,537,666	93,933	0.0266	0.9734	88.85
38.5	2,345,924	375	0.0002	0.9998	86.49

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 390.20 STRUCTURES AND IMPROVEMENTS - CLEARING

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2021 EXPERIENCE BAND 2003-2021

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	2,150,297	8,806	0.0041	0.9959	86.47
40.5	1,920,039	2,276	0.0012	0.9988	86.12
41.5	2,015,514	806	0.0004	0.9996	86.02
42.5	1,893,569	49,065	0.0259	0.9741	85.98
43.5	1,748,507	10,683	0.0061	0.9939	83.76
44.5	1,863,492		0.0000	1.0000	83.24
45.5	1,886,242	17,889	0.0095	0.9905	83.24
46.5	1,889,427	1,790	0.0009	0.9991	82.45
47.5	1,835,921	1,535	0.0008	0.9992	82.38
48.5	1,824,104	39,369	0.0216	0.9784	82.31
49.5	1,774,425		0.0000	1.0000	80.53
50.5	1,773,768	3,409	0.0019	0.9981	80.53
51.5	1,632,477	4,015	0.0025	0.9975	80.38
52.5	1,554,592	7,520	0.0048	0.9952	80.18
53.5	1,476,149	6,003	0.0041	0.9959	79.79
54.5	1,325,229	4,373	0.0033	0.9967	79.47
55.5	975,863	3,608	0.0037	0.9963	79.20
56.5	861,173	480	0.0006	0.9994	78.91
57.5	714,872	13,288	0.0186	0.9814	78.87
58.5	663,617	3,135	0.0047	0.9953	77.40
59.5	482,986	42,447	0.0879	0.9121	77.04
60.5	390,489		0.0000	1.0000	70.27
61.5	333,903	218	0.0007	0.9993	70.27
62.5	228,684	3,342	0.0146	0.9854	70.22
63.5	187,770	6,928	0.0369	0.9631	69.19
64.5	159,031		0.0000	1.0000	66.64
65.5	94,003		0.0000	1.0000	66.64
66.5	81,138	536	0.0066	0.9934	66.64
67.5	41,314	1,687	0.0408	0.9592	66.20
68.5	13,965	111	0.0080	0.9920	63.50
69.5	13,854		0.0000	1.0000	62.99
70.5	7,775		0.0000	1.0000	62.99
71.5	8,414	309	0.0367	0.9633	62.99
72.5	8,106		0.0000	1.0000	60.68
73.5	9,145		0.0000	1.0000	60.68
74.5	18,702		0.0000	1.0000	60.68
75.5	63,864		0.0000	1.0000	60.68
76.5	65,388		0.0000	1.0000	60.68
77.5	66,438		0.0000	1.0000	60.68
78.5	71,809	89	0.0012	0.9988	60.68

JERSEY CENTRAL POWER & LIGHT COMPANY

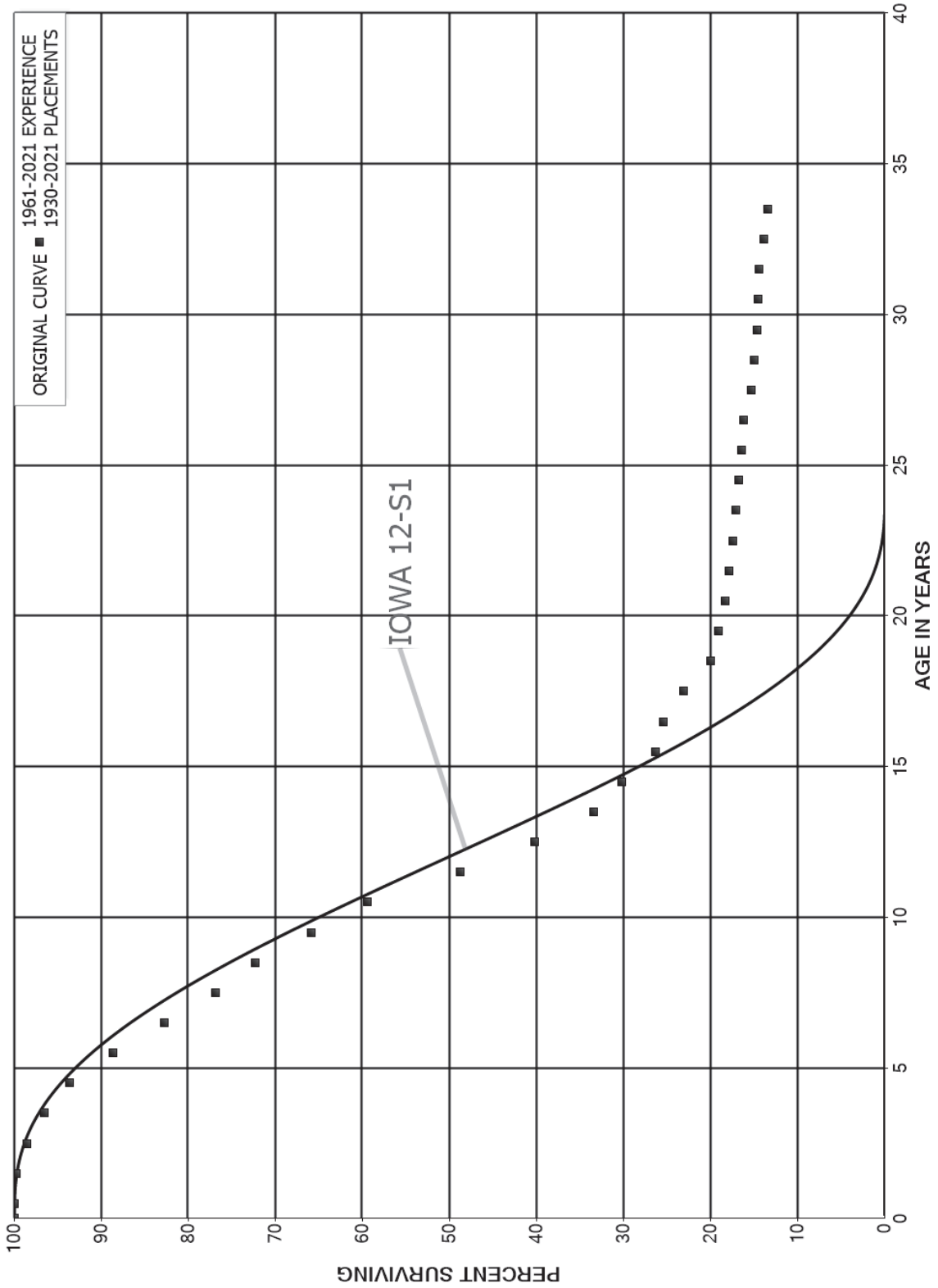
ACCOUNT 390.20 STRUCTURES AND IMPROVEMENTS - CLEARING

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1910-2021 EXPERIENCE BAND 2003-2021

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	73,235	265	0.0036	0.9964	60.60
80.5	73,901	174	0.0024	0.9976	60.39
81.5	74,090		0.0000	1.0000	60.24
82.5	74,050		0.0000	1.0000	60.24
83.5	70,587		0.0000	1.0000	60.24
84.5	71,067		0.0000	1.0000	60.24
85.5	72,664		0.0000	1.0000	60.24
86.5	72,629		0.0000	1.0000	60.24
87.5	72,629		0.0000	1.0000	60.24
88.5	72,629		0.0000	1.0000	60.24
89.5	71,921	2,504	0.0348	0.9652	60.24
90.5	69,417	4,133	0.0595	0.9405	58.15
91.5	64,163	2,521	0.0393	0.9607	54.68
92.5	55,060	1,050	0.0191	0.9809	52.53
93.5	14,014	5,331	0.3804	0.6196	51.53
94.5	8,683		0.0000	1.0000	31.93
95.5	8,683		0.0000	1.0000	31.93
96.5	8,355		0.0000	1.0000	31.93
97.5	6,839		0.0000	1.0000	31.93
98.5	4,202		0.0000	1.0000	31.93
99.5	3,810		0.0000	1.0000	31.93
100.5	3,810		0.0000	1.0000	31.93
101.5	3,810		0.0000	1.0000	31.93
102.5	3,330		0.0000	1.0000	31.93
103.5	1,734		0.0000	1.0000	31.93
104.5	1,734		0.0000	1.0000	31.93
105.5	1,734		0.0000	1.0000	31.93
106.5	1,734		0.0000	1.0000	31.93
107.5	1,734		0.0000	1.0000	31.93
108.5	1,734	1,032	0.5954	0.4046	31.93
109.5	702		0.0000	1.0000	12.92
110.5					12.92

JERSEY CENTRAL POWER & LIGHT COMPANY
ACCOUNT 392.00 TRANSPORTATION EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 392.00 TRANSPORTATION EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1930-2021 EXPERIENCE BAND 1961-2021

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	33,210,995		0.0000	1.0000	100.00
0.5	27,179,463	82,859	0.0030	0.9970	100.00
1.5	25,890,307	323,068	0.0125	0.9875	99.70
2.5	20,026,224	384,698	0.0192	0.9808	98.45
3.5	20,079,272	612,206	0.0305	0.9695	96.56
4.5	18,602,724	994,733	0.0535	0.9465	93.62
5.5	18,111,267	1,196,352	0.0661	0.9339	88.61
6.5	17,088,051	1,219,995	0.0714	0.9286	82.76
7.5	16,011,349	948,702	0.0593	0.9407	76.85
8.5	14,397,858	1,295,796	0.0900	0.9100	72.29
9.5	13,207,937	1,276,127	0.0966	0.9034	65.79
10.5	11,969,267	2,165,956	0.1810	0.8190	59.43
11.5	9,907,001	1,725,146	0.1741	0.8259	48.68
12.5	7,547,168	1,269,404	0.1682	0.8318	40.20
13.5	6,288,352	618,852	0.0984	0.9016	33.44
14.5	5,087,495	643,299	0.1264	0.8736	30.15
15.5	4,568,154	164,380	0.0360	0.9640	26.34
16.5	4,336,079	392,177	0.0904	0.9096	25.39
17.5	3,977,617	536,879	0.1350	0.8650	23.09
18.5	3,387,651	147,382	0.0435	0.9565	19.98
19.5	3,240,758	131,610	0.0406	0.9594	19.11
20.5	3,106,127	76,614	0.0247	0.9753	18.33
21.5	3,032,083	76,480	0.0252	0.9748	17.88
22.5	2,630,104	55,083	0.0209	0.9791	17.43
23.5	1,863,968	41,086	0.0220	0.9780	17.06
24.5	1,697,395	25,425	0.0150	0.9850	16.69
25.5	1,690,349	23,295	0.0138	0.9862	16.44
26.5	1,628,233	91,145	0.0560	0.9440	16.21
27.5	1,358,611	30,216	0.0222	0.9778	15.30
28.5	1,152,313	23,064	0.0200	0.9800	14.96
29.5	1,064,933	15,053	0.0141	0.9859	14.66
30.5	781,239	4,955	0.0063	0.9937	14.46
31.5	745,069	27,136	0.0364	0.9636	14.36
32.5	717,933	23,552	0.0328	0.9672	13.84
33.5	534,969	28,815	0.0539	0.9461	13.39
34.5	308,876	15,398	0.0499	0.9501	12.67
35.5	295,698	11,017	0.0373	0.9627	12.03
36.5	200,086	8,930	0.0446	0.9554	11.59
37.5	190,229	11,189	0.0588	0.9412	11.07
38.5	178,906	9,407	0.0526	0.9474	10.42

JERSEY CENTRAL POWER & LIGHT COMPANY

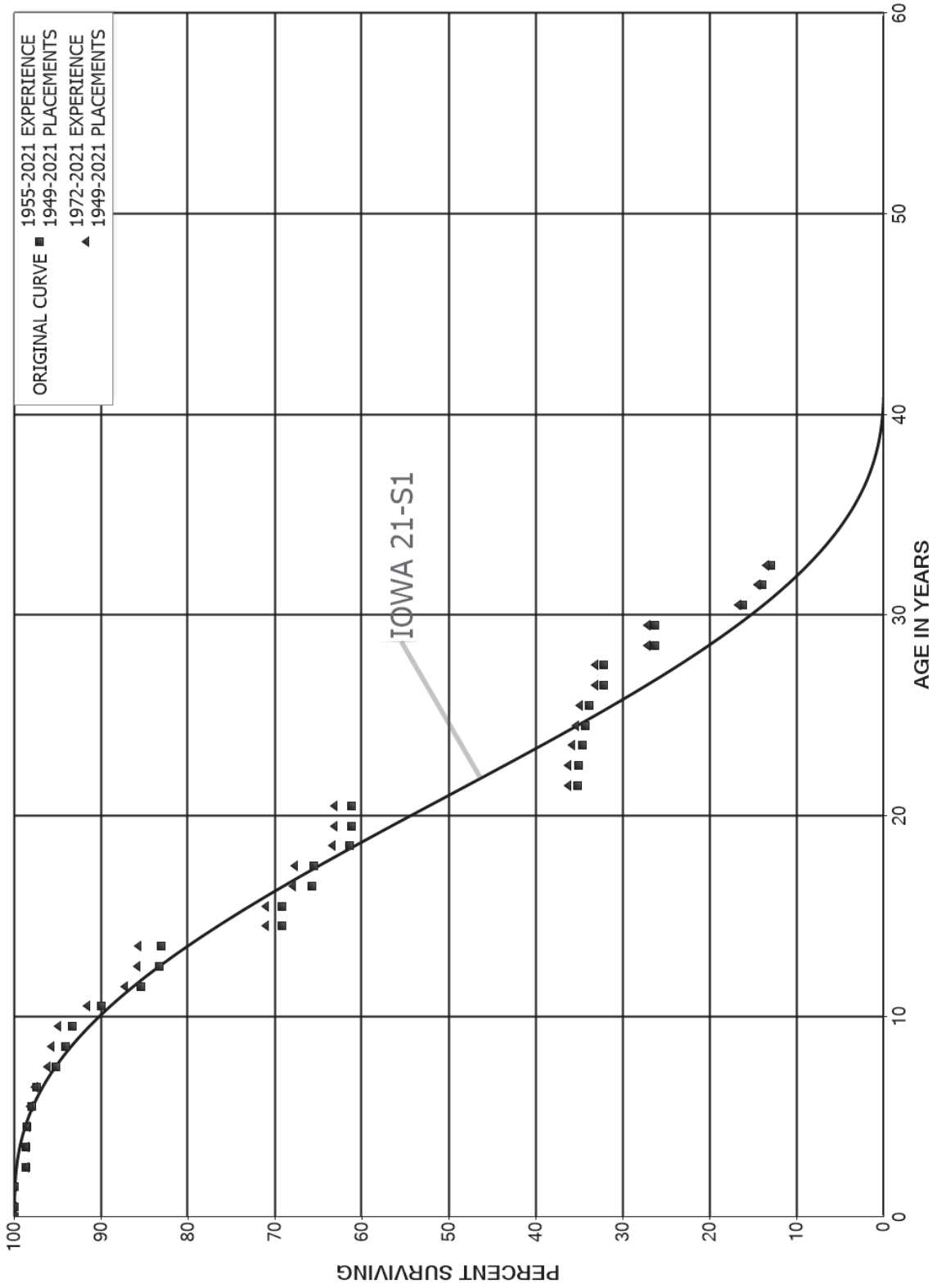
ACCOUNT 392.00 TRANSPORTATION EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1930-2021 EXPERIENCE BAND 1961-2021

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	169,781	24,724	0.1456	0.8544	9.87
40.5	145,057	3,077	0.0212	0.9788	8.43
41.5	138,180	928	0.0067	0.9933	8.25
42.5	110,233	3,316	0.0301	0.9699	8.20
43.5	102,202	3,564	0.0349	0.9651	7.95
44.5	89,613	1,570	0.0175	0.9825	7.67
45.5	50,784		0.0000	1.0000	7.54
46.5	50,784	333	0.0066	0.9934	7.54
47.5	50,327	108	0.0021	0.9979	7.49
48.5	50,097		0.0000	1.0000	7.47
49.5	49,853	166	0.0033	0.9967	7.47
50.5	46,587	1,044	0.0224	0.9776	7.45
51.5	46,052	1,834	0.0398	0.9602	7.28
52.5	17,237	585	0.0339	0.9661	6.99
53.5	8,854	713	0.0805	0.9195	6.76
54.5	5,506		0.0000	1.0000	6.21
55.5	5,506		0.0000	1.0000	6.21
56.5	5,506		0.0000	1.0000	6.21
57.5	4,567		0.0000	1.0000	6.21
58.5	1,942		0.0000	1.0000	6.21
59.5	1,942	124	0.0637	0.9363	6.21
60.5	1,818	199	0.1094	0.8906	5.82
61.5	1,619		0.0000	1.0000	5.18
62.5	1,619		0.0000	1.0000	5.18
63.5	1,619	1,476	0.9119	0.0881	5.18
64.5	143		0.0000	1.0000	0.46
65.5	143	143	1.0000		0.46
66.5					

JERSEY CENTRAL POWER & LIGHT COMPANY
ACCOUNT 396.00 POWER OPERATED EQUIPMENT
ORIGINAL AND SMOOTH SURVIVOR CURVES



JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 396.00 POWER OPERATED EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1949-2021 EXPERIENCE BAND 1955-2021

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	4,304,682		0.0000	1.0000	100.00
0.5	4,642,372	3,337	0.0007	0.9993	100.00
1.5	4,652,585	61,869	0.0133	0.9867	99.93
2.5	5,925,913	684	0.0001	0.9999	98.60
3.5	5,841,876	5,364	0.0009	0.9991	98.59
4.5	6,427,884	32,269	0.0050	0.9950	98.50
5.5	6,234,309	37,642	0.0060	0.9940	98.00
6.5	5,774,322	135,774	0.0235	0.9765	97.41
7.5	5,642,543	62,094	0.0110	0.9890	95.12
8.5	5,563,071	45,188	0.0081	0.9919	94.07
9.5	5,478,138	199,708	0.0365	0.9635	93.31
10.5	5,275,764	264,626	0.0502	0.9498	89.91
11.5	5,014,511	122,712	0.0245	0.9755	85.40
12.5	4,778,632	11,185	0.0023	0.9977	83.31
13.5	4,747,920	796,019	0.1677	0.8323	83.11
14.5	3,951,901		0.0000	1.0000	69.18
15.5	3,951,901	198,058	0.0501	0.9499	69.18
16.5	3,757,042	11,101	0.0030	0.9970	65.71
17.5	3,727,902	234,564	0.0629	0.9371	65.52
18.5	3,486,674	13,695	0.0039	0.9961	61.40
19.5	3,472,979		0.0000	1.0000	61.15
20.5	3,357,241	1,426,856	0.4250	0.5750	61.15
21.5	1,925,699	2,716	0.0014	0.9986	35.16
22.5	1,935,582	25,503	0.0132	0.9868	35.11
23.5	1,185,941	13,635	0.0115	0.9885	34.65
24.5	1,172,306	12,599	0.0107	0.9893	34.25
25.5	1,159,707	60,100	0.0518	0.9482	33.88
26.5	942,185		0.0000	1.0000	32.13
27.5	827,167	150,484	0.1819	0.8181	32.13
28.5	549,127		0.0000	1.0000	26.28
29.5	486,929	187,586	0.3852	0.6148	26.28
30.5	259,779	35,353	0.1361	0.8639	16.16
31.5	224,426	15,633	0.0697	0.9303	13.96
32.5	208,793		0.0000	1.0000	12.99
33.5	208,793		0.0000	1.0000	12.99
34.5	204,642		0.0000	1.0000	12.99
35.5	204,642		0.0000	1.0000	12.99
36.5	182,084		0.0000	1.0000	12.99
37.5	182,084	24,703	0.1357	0.8643	12.99
38.5	157,382		0.0000	1.0000	11.22

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 396.00 POWER OPERATED EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1949-2021 EXPERIENCE BAND 1955-2021

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	157,382	41,657	0.2647	0.7353	11.22
40.5	115,725		0.0000	1.0000	8.25
41.5	115,725		0.0000	1.0000	8.25
42.5	115,725		0.0000	1.0000	8.25
43.5	115,725		0.0000	1.0000	8.25
44.5	115,725		0.0000	1.0000	8.25
45.5	78,981		0.0000	1.0000	8.25
46.5	78,981		0.0000	1.0000	8.25
47.5	78,981		0.0000	1.0000	8.25
48.5	78,981		0.0000	1.0000	8.25
49.5	76,594		0.0000	1.0000	8.25
50.5	76,594		0.0000	1.0000	8.25
51.5	76,594		0.0000	1.0000	8.25
52.5	27,605		0.0000	1.0000	8.25
53.5	27,605		0.0000	1.0000	8.25
54.5	27,605		0.0000	1.0000	8.25
55.5	27,605		0.0000	1.0000	8.25
56.5	540		0.0000	1.0000	8.25
57.5	540		0.0000	1.0000	8.25
58.5	540		0.0000	1.0000	8.25
59.5	540		0.0000	1.0000	8.25
60.5	540		0.0000	1.0000	8.25
61.5	540		0.0000	1.0000	8.25
62.5	540		0.0000	1.0000	8.25
63.5	540		0.0000	1.0000	8.25
64.5					8.25

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 396.00 POWER OPERATED EQUIPMENT

ORIGINAL LIFE TABLE

PLACEMENT BAND 1949-2021 EXPERIENCE BAND 1972-2021

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	3,599,531		0.0000	1.0000	100.00
0.5	3,971,766		0.0000	1.0000	100.00
1.5	4,054,708	61,869	0.0153	0.9847	100.00
2.5	5,465,935	684	0.0001	0.9999	98.47
3.5	5,395,016	4,278	0.0008	0.9992	98.46
4.5	5,940,486	21,151	0.0036	0.9964	98.38
5.5	5,849,361	32,248	0.0055	0.9945	98.03
6.5	5,494,477	78,644	0.0143	0.9857	97.49
7.5	5,399,071	26,518	0.0049	0.9951	96.10
8.5	5,424,683	45,188	0.0083	0.9917	95.63
9.5	5,311,413	183,875	0.0346	0.9654	94.83
10.5	5,140,730	242,377	0.0471	0.9529	91.55
11.5	4,882,154	81,767	0.0167	0.9833	87.23
12.5	4,687,221	11,185	0.0024	0.9976	85.77
13.5	4,656,509	796,019	0.1709	0.8291	85.56
14.5	3,874,725		0.0000	1.0000	70.94
15.5	3,910,017	172,687	0.0442	0.9558	70.94
16.5	3,745,161	11,000	0.0029	0.9971	67.80
17.5	3,716,122	234,564	0.0631	0.9369	67.61
18.5	3,474,894	13,695	0.0039	0.9961	63.34
19.5	3,461,199		0.0000	1.0000	63.09
20.5	3,348,177	1,426,856	0.4262	0.5738	63.09
21.5	1,916,635	2,716	0.0014	0.9986	36.20
22.5	1,935,582	25,503	0.0132	0.9868	36.15
23.5	1,185,941	13,635	0.0115	0.9885	35.67
24.5	1,172,306	12,599	0.0107	0.9893	35.26
25.5	1,159,707	60,100	0.0518	0.9482	34.89
26.5	942,185		0.0000	1.0000	33.08
27.5	827,167	150,484	0.1819	0.8181	33.08
28.5	549,127		0.0000	1.0000	27.06
29.5	486,929	187,586	0.3852	0.6148	27.06
30.5	259,779	35,353	0.1361	0.8639	16.64
31.5	224,426	15,633	0.0697	0.9303	14.37
32.5	208,793		0.0000	1.0000	13.37
33.5	208,793		0.0000	1.0000	13.37
34.5	204,642		0.0000	1.0000	13.37
35.5	204,642		0.0000	1.0000	13.37
36.5	182,084		0.0000	1.0000	13.37
37.5	182,084	24,703	0.1357	0.8643	13.37
38.5	157,382		0.0000	1.0000	11.56

JERSEY CENTRAL POWER & LIGHT COMPANY

ACCOUNT 396.00 POWER OPERATED EQUIPMENT

ORIGINAL LIFE TABLE, CONT.

PLACEMENT BAND 1949-2021 EXPERIENCE BAND 1972-2021

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	157,382	41,657	0.2647	0.7353	11.56
40.5	115,725		0.0000	1.0000	8.50
41.5	115,725		0.0000	1.0000	8.50
42.5	115,725		0.0000	1.0000	8.50
43.5	115,725		0.0000	1.0000	8.50
44.5	115,725		0.0000	1.0000	8.50
45.5	78,981		0.0000	1.0000	8.50
46.5	78,981		0.0000	1.0000	8.50
47.5	78,981		0.0000	1.0000	8.50
48.5	78,981		0.0000	1.0000	8.50
49.5	76,594		0.0000	1.0000	8.50
50.5	76,594		0.0000	1.0000	8.50
51.5	76,594		0.0000	1.0000	8.50
52.5	27,605		0.0000	1.0000	8.50
53.5	27,605		0.0000	1.0000	8.50
54.5	27,605		0.0000	1.0000	8.50
55.5	27,605		0.0000	1.0000	8.50
56.5	540		0.0000	1.0000	8.50
57.5	540		0.0000	1.0000	8.50
58.5	540		0.0000	1.0000	8.50
59.5	540		0.0000	1.0000	8.50
60.5	540		0.0000	1.0000	8.50
61.5	540		0.0000	1.0000	8.50
62.5	540		0.0000	1.0000	8.50
63.5	540		0.0000	1.0000	8.50
64.5					8.50

PART VIII. DETAILED DEPRECIATION CALCULATIONS

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 303.00 MISCELLANEOUS INTANGIBLE PLANT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FULLY ACCRUED						
1994	3,082,834.87	3,082,835	3,082,835			
1997	56,126.64	56,127	56,127			
2000	15.01	15	15			
2001	20,714.75	20,715	20,715			
2002	219,074.31	219,074	219,074			
2003	17,518,007.19	17,518,007	17,518,007			
2004	4,293,043.40	4,293,043	4,293,043			
2005	1,410,929.11	1,410,929	1,410,929			
2006	2,244,358.68	2,244,359	2,244,359			
2007	12,380,874.55	12,380,875	12,380,875			
2008	1,124,813.27	1,124,813	1,124,813			
2009	3,770,625.17	3,770,625	3,770,625			
2010	1,857,352.77	1,857,353	1,857,353			
2011	5,173,723.35	5,173,723	5,173,723			
2012	2,329,496.78	2,329,497	2,329,497			
2013	2,826,861.41	2,826,861	2,826,861			
2014	9,333,215.80	9,333,216	9,333,216			
2015	4,493,787.56	4,493,788	4,493,788			
	72,135,854.62	72,135,855	72,135,855			
AMORTIZED SURVIVOR CURVE.. 7-SQUARE						
2016	7,287,015.04	6,245,992	6,316,411	970,604	1.00	970,604
2017	7,847,463.23	5,605,365	5,668,561	2,178,902	2.00	1,089,451
2018	18,313,039.33	10,464,620	10,582,600	7,730,439	3.00	2,576,813
2019	11,923,856.46	5,110,207	5,167,821	6,756,036	4.00	1,689,009
2020	10,129,196.46	2,894,013	2,926,641	7,202,556	5.00	1,440,511
2021	3,548,493.88	506,938	512,653	3,035,841	6.00	505,974
2022	2,383,191.75	85,104	86,063	2,297,128	6.75	340,315
	61,432,256.15	30,912,239	31,260,750	30,171,506		8,612,677
	133,568,110.77	103,048,094	103,396,605	30,171,506		8,612,677

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 3.5 6.45

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 360.12 DISTRIBUTION SUBSTATION EASEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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 85-R4						
1928	183.01	164	183			
1930	100.00	89	100			
1943	1.00	1	1			
1952	203.00	152	181	22	21.37	1
1956	5,832.75	4,173	4,979	854	24.19	35
1957	1,017.73	719	858	160	24.92	6
1958	1,257.53	878	1,048	210	25.65	8
1959	99.69	69	82	18	26.40	1
1960	3,996.46	2,720	3,246	750	27.15	28
1963	2,527.16	1,651	1,970	557	29.46	19
1964	13,494.95	8,692	10,371	3,124	30.25	103
1965	12,421.93	7,884	9,407	3,015	31.05	97
1967	6,690.70	4,119	4,915	1,776	32.67	54
1968	8,060.51	4,885	5,829	2,232	33.49	67
1970	2,377.33	1,394	1,663	714	35.17	20
1974	1,510.61	824	983	528	38.61	14
1976	11,781.13	6,186	7,381	4,400	40.37	109
1978	13,975.33	7,044	8,405	5,570	42.16	132
1979	7.00	3	4	3	43.07	
1981	1.00			1	44.90	
1982	1.00			1	45.82	
1984	1.00			1	47.68	
1985	11,273.13	4,825	5,757	5,516	48.62	113
1988	1.00			1	51.46	
1989	1.00			1	52.41	
1990	5,614.50	2,089	2,493	3,122	53.37	58
1991	100.62	36	43	58	54.34	1
2006	203,534.24	38,193	45,573	157,961	69.05	2,288
2007	384,519.00	67,675	80,750	303,769	70.04	4,337
2019	222.13	8	10	212	82.00	3
	690,806.44	164,473	196,232	494,574		7,494

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 66.0 1.08

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 360.22 DISTRIBUTION LINE EASEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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 85-R4						
1930	2,788.84	2,474	2,789			
1931	2,988.42	2,638	2,988			
1932	1,276.22	1,121	1,276			
1933	1,382.45	1,208	1,382			
1934	1,083.92	942	1,084			
1935	927.75	802	928			
1936	2,363.57	2,030	2,364			
1937	1,095.30	935	1,095			
1938	137,331.58	116,474	137,332			
1939	8,158.44	6,871	8,158			
1940	9,668.09	8,085	9,668			
1941	10,652.77	8,842	10,653			
1942	2,870.31	2,363	2,870			
1943	20,692.30	16,900	20,692			
1944	3,736.53	3,026	3,737			
1945	3,944.63	3,166	3,945			
1946	13,891.87	11,050	13,892			
1947	9,018.41	7,105	9,018			
1948	10,384.91	8,104	10,385			
1949	13,843.28	10,695	13,843			
1950	11,248.97	8,602	11,249			
1951	14,504.71	10,976	14,505			
1952	18,393.46	13,769	18,393			
1953	18,582.66	13,760	18,583			
1954	16,504.90	12,086	16,505			
1955	23,851.38	17,266	23,851			
1956	16,749.16	11,983	16,749			
1957	48,216.75	34,081	48,217			
1958	59,956.46	41,864	59,956			
1959	81,691.25	56,319	81,691			
1960	99,468.80	67,697	99,469			
1961	109,149.28	73,310	109,149			
1962	121,881.86	80,758	121,882			
1963	143,654.96	93,866	143,655			
1964	161,307.10	103,901	161,307			
1965	178,932.71	113,570	178,933			
1966	220,883.03	138,092	220,883			
1967	237,352.36	146,126	237,352			
1968	265,514.89	160,902	265,515			
1969	267,828.12	159,658	267,828			
1970	295,491.78	173,229	294,974	518	35.17	15
1971	264,513.10	152,452	259,595	4,918	36.01	137
1972	371,888.06	210,578	358,572	13,316	36.87	361
1973	318,298.00	177,012	301,416	16,882	37.73	447

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 360.22 DISTRIBUTION LINE EASEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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 85-R4						
1974	417,169.50	227,674	387,683	29,486	38.61	764
1975	338,779.81	181,427	308,934	29,846	39.48	756
1976	491,350.20	257,988	439,302	52,048	40.37	1,289
1977	472,206.55	242,993	413,769	58,438	41.26	1,416
1978	579,317.79	291,976	497,177	82,141	42.16	1,948
1979	789,185.02	389,297	662,895	126,290	43.07	2,932
1980	671,560.24	324,088	551,857	119,703	43.98	2,722
1981	499,457.74	235,624	401,221	98,237	44.90	2,188
1982	463,839.23	213,802	364,062	99,777	45.82	2,178
1983	840,884.70	378,398	644,336	196,549	46.75	4,204
1984	1,701,196.11	746,927	1,271,868	429,328	47.68	9,004
1985	643,386.53	275,369	468,898	174,489	48.62	3,589
1986	1,258,408.13	524,681	893,427	364,981	49.56	7,364
1987	881,132.46	357,528	608,799	272,333	50.51	5,392
1988	1,091,928.12	430,864	733,675	358,253	51.46	6,962
1989	865,120.75	331,696	564,812	300,309	52.41	5,730
1990	1,015,041.51	377,717	643,177	371,865	53.37	6,968
1991	1,501,280.76	541,527	922,113	579,168	54.34	10,658
1992	1,643,685.61	574,320	977,952	665,734	55.30	12,039
1993	1,600,930.86	541,115	921,411	679,520	56.27	12,076
1994	613,583.49	200,390	341,224	272,359	57.24	4,758
1995	670,391.39	211,294	359,792	310,599	58.21	5,336
1996	270,316.85	82,082	139,769	130,548	59.19	2,206
1997	821,919.92	240,099	408,841	413,079	60.17	6,865
1998	1,342,650.46	376,734	641,503	701,147	61.15	11,466
2000	1,119,083.05	288,063	490,514	628,569	63.12	9,958
2002	2,252.46	528	899	1,353	65.09	21
2003	25,800.30	5,743	9,779	16,021	66.08	242
	26,255,822.88	11,136,632	18,658,017	7,597,806		141,991

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 53.5 0.54

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 361.10 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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-R4						
1896	17,563.36	17,563	17,563			
1901	2,522.11	2,522	2,522			
1905	28,908.31	28,908	28,908			
1910	4,015.77	3,987	4,016			
1911	196.83	195	197			
1912	10,357.35	10,232	10,357			
1922	962.90	923	963			
1923	13,523.79	12,913	13,524			
1924	1,450.07	1,380	1,450			
1925	20,868.07	19,786	20,868			
1926	6,945.69	6,561	6,946			
1927	21,715.95	20,439	21,716			
1928	7,777.41	7,293	7,777			
1929	1,079.57	1,008	1,080			
1930	5,559.57	5,174	5,560			
1931	23,277.08	21,579	23,277			
1932	3,536.77	3,266	3,537			
1933	1,150.45	1,058	1,150			
1934	78.84	72	79			
1935	168.81	154	169			
1936	53.70	49	54			
1937	1,025.27	927	1,025			
1938	562.27	506	562			
1939	1,426.23	1,277	1,426			
1940	8,996.64	8,015	8,997			
1941	2,299.03	2,038	2,299			
1942	9,467.26	8,345	9,467			
1943	7,798.31	6,834	7,798			
1946	77.19	66	77			
1947	36,874.82	31,476	36,875			
1948	19,198.52	16,267	19,199			
1949	4,638.44	3,899	4,638			
1950	125,737.26	104,831	125,737			
1951	74,998.75	61,989	74,999			
1952	50,562.20	41,407	50,562			
1953	80,028.61	64,919	80,029			
1954	21,386.47	17,178	21,386			
1955	156,827.68	124,667	156,828			
1956	180,399.55	141,866	180,400			
1957	75,659.26	58,842	75,659			
1958	100,859.16	77,554	100,859			
1959	106,534.07	80,952	106,534			
1960	92,133.20	69,174	91,736	397	18.69	21
1961	82,669.02	61,307	81,303	1,366	19.38	70

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 361.10 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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-R4						
1962	161,783.85	118,469	157,109	4,675	20.08	233
1963	61,155.57	44,203	58,620	2,536	20.79	122
1964	161,446.26	115,143	152,698	8,748	21.51	407
1965	109,505.32	77,034	102,160	7,345	22.24	330
1966	237,990.28	165,070	218,910	19,080	22.98	830
1967	212,231.42	145,081	192,401	19,830	23.73	836
1968	431,430.26	290,555	385,323	46,107	24.49	1,883
1969	460,787.09	305,594	405,268	55,519	25.26	2,198
1970	512,390.26	334,488	443,586	68,804	26.04	2,642
1971	620,636.07	398,616	528,630	92,006	26.83	3,429
1972	242,757.92	153,326	203,335	39,423	27.63	1,427
1973	240,804.08	149,491	198,250	42,554	28.44	1,496
1974	113,280.31	69,086	91,619	21,661	29.26	740
1975	233,555.86	139,853	185,468	48,088	30.09	1,598
1976	144,738.77	85,049	112,789	31,950	30.93	1,033
1977	80,899.09	46,620	61,826	19,073	31.78	600
1978	112,631.03	63,629	84,382	28,249	32.63	866
1979	128,146.00	70,907	94,034	34,112	33.50	1,018
1980	43,239.39	23,424	31,064	12,175	34.37	354
1981	18,492.22	9,798	12,994	5,498	35.26	156
1982	204,778.77	106,075	140,673	64,106	36.15	1,773
1983	115,905.93	58,663	77,797	38,109	37.04	1,029
1984	237,075.15	117,115	155,314	81,761	37.95	2,154
1985	326,515.31	157,338	208,656	117,859	38.86	3,033
1986	808,934.09	379,875	503,776	305,158	39.78	7,671
1987	1,228,040.37	561,620	744,800	483,240	40.70	11,873
1988	711,400.49	316,523	419,761	291,639	41.63	7,006
1989	1,621,070.85	700,951	929,576	691,495	42.57	16,244
1990	277,420.97	116,481	154,473	122,948	43.51	2,826
1991	356,884.16	145,370	192,784	164,100	44.45	3,692
1992	2,485,893.83	980,760	1,300,649	1,185,245	45.41	26,101
1993	443,117.50	169,213	224,404	218,714	46.36	4,718
1994	127,145.21	46,925	62,230	64,915	47.32	1,372
1995	612,644.57	218,267	289,458	323,187	48.28	6,694
1996	1,207,365.27	414,525	549,728	657,637	49.25	13,353
1998	111,879.87	35,519	47,104	64,776	51.19	1,265
1999	1,910.27	581	771	1,139	52.17	22
2002	6,795.20	1,802	2,390	4,405	55.11	80
2005	1,387,169.96	313,126	415,256	971,914	58.07	16,737
2006	363,360.16	77,225	102,413	260,947	59.06	4,418
2007	602,618.52	120,120	159,299	443,320	60.05	7,383
2008	718,047.46	133,650	177,242	540,805	61.04	8,860
2009	106,675.57	18,434	24,446	82,230	62.04	1,325
2010	49,362.33	7,878	10,448	38,914	63.03	617

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 361.10 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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-R4						
2011	101,072.58	14,784	19,606	81,467	64.03	1,272
2012	630,171.68	83,857	111,208	518,964	65.02	7,982
2013	535,123.70	64,070	84,967	450,157	66.02	6,818
2015	457,649.17	42,653	56,565	401,084	68.01	5,897
2016	1,861,655.85	148,690	197,187	1,664,469	69.01	24,119
2017	529,087.42	35,200	46,681	482,406	70.01	6,891
2018	359,905.69	19,194	25,454	334,452	71.00	4,711
2019	1,890,577.91	75,623	100,289	1,790,289	72.00	24,865
2020	701,082.85	18,698	24,796	676,287	73.00	9,264
2021	64,589.00	861	1,142	63,447	74.00	857
2022	5,432.65	18	24	5,409	74.75	72
	26,988,132.97	9,656,518	12,691,941	14,296,192		265,283

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 53.9 0.98

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 361.20 STRUCTURES AND IMPROVEMENTS - CLEARING

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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-R4						
1956	16,369.44	12,873	16,369			
2006	66,892.56	14,217	20,037	46,856	59.06	793
2007	924,656.01	184,312	259,765	664,891	60.05	11,072
2008	65,125.23	12,122	17,084	48,041	61.04	787
2009	189,807.78	32,799	46,226	143,582	62.04	2,314
2010	165,692.99	26,445	37,271	128,422	63.03	2,037
2012	576,263.83	76,683	108,075	468,189	65.02	7,201
2014	2,327,581.76	247,957	349,465	1,978,117	67.01	29,520
2016	9,463,183.37	755,824	1,065,242	8,397,941	69.01	121,692
2019	1,409,223.85	56,369	79,445	1,329,779	72.00	18,469
2020	48,337,740.90	1,289,168	1,816,926	46,520,815	73.00	637,271
2021	489,434.52	6,524	9,195	480,240	74.00	6,490
2022	12,218.75	41	58	12,161	74.75	163
	64,044,190.99	2,715,334	3,825,158	60,219,033		837,809

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 71.9 1.31

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 362.00 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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 59-R2						
1901	6,381.29	6,381	6,381			
1914	49.67	49	50			
1915	50.13	50	50			
1917	62.11	61	62			
1918	57.54	56	58			
1919	349.23	339	349			
1920	130.07	126	130			
1921	252.91	243	253			
1922	764.27	732	764			
1923	4,134.55	3,939	4,135			
1924	899.75	853	900			
1925	1,136.11	1,072	1,136			
1926	9,265.01	8,693	9,265			
1927	16,313.69	15,227	16,314			
1928	15,445.92	14,344	15,446			
1929	12,967.41	11,978	12,967			
1930	10,388.55	9,545	10,389			
1931	52,196.82	47,703	52,197			
1932	7,945.87	7,223	7,946			
1933	13,373.42	12,091	13,373			
1934	1,269.93	1,142	1,270			
1935	8,408.36	7,519	8,408			
1936	13,007.05	11,567	13,007			
1937	55,132.63	48,750	55,133			
1938	7,042.40	6,193	7,042			
1939	8,408.93	7,351	8,409			
1940	30,228.26	26,273	30,228			
1941	29,759.22	25,714	29,759			
1942	53,806.80	46,210	53,807			
1943	13,942.75	11,901	13,943			
1944	1,946.94	1,652	1,947			
1945	683.63	576	684			
1946	681.56	571	682			
1947	57,080.10	47,483	57,080			
1948	183,362.46	151,476	183,362			
1949	122,156.26	100,210	121,786	370	10.60	35
1950	294,143.27	239,503	291,070	3,073	10.96	280
1951	588,877.67	475,996	578,481	10,397	11.31	919
1952	246,829.53	197,965	240,588	6,242	11.68	534
1953	471,504.20	375,124	455,891	15,613	12.06	1,295
1954	576,012.41	454,560	552,430	23,582	12.44	1,896
1955	919,672.40	719,680	874,632	45,040	12.83	3,511
1956	969,855.70	752,210	914,166	55,690	13.24	4,206
1957	1,100,162.76	845,629	1,027,699	72,464	13.65	5,309

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 362.00 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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 59-R2						
1958	1,429,082.19	1,088,289	1,322,606	106,476	14.07	7,568
1959	1,052,384.25	793,750	964,650	87,734	14.50	6,051
1960	1,094,548.82	817,387	993,376	101,173	14.94	6,772
1961	695,640.08	514,182	624,889	70,751	15.39	4,597
1962	1,205,058.95	881,332	1,071,089	133,970	15.85	8,452
1963	653,957.20	473,066	574,921	79,036	16.32	4,843
1964	1,723,927.76	1,233,039	1,498,521	225,407	16.80	13,417
1965	1,386,678.57	980,312	1,191,380	195,299	17.29	11,295
1966	2,700,167.52	1,885,986	2,292,053	408,115	17.79	22,941
1967	3,980,488.09	2,745,860	3,337,064	643,424	18.30	35,160
1968	4,461,233.84	3,037,431	3,691,412	769,822	18.83	40,883
1969	5,779,316.35	3,882,891	4,718,906	1,060,410	19.36	54,773
1970	5,874,460.98	3,893,064	4,731,269	1,143,192	19.90	57,447
1971	6,432,339.87	4,202,827	5,107,727	1,324,613	20.45	64,773
1972	5,731,131.80	3,690,276	4,484,820	1,246,312	21.01	59,320
1973	6,393,096.98	4,054,758	4,927,777	1,465,320	21.58	67,902
1974	2,393,490.10	1,494,519	1,816,300	577,190	22.16	26,046
1975	4,083,217.47	2,508,770	3,048,927	1,034,290	22.75	45,463
1976	1,542,485.48	932,031	1,132,704	409,781	23.35	17,550
1977	846,682.12	502,845	611,111	235,571	23.96	9,832
1978	1,359,711.01	793,242	964,033	395,678	24.58	16,098
1979	5,222,683.23	2,991,971	3,636,164	1,586,519	25.20	62,957
1980	2,910,879.82	1,636,002	1,988,245	922,635	25.84	35,706
1981	279,826.17	154,237	187,445	92,381	26.48	3,489
1982	5,347,222.22	2,887,500	3,509,200	1,838,022	27.14	67,724
1983	1,063,280.63	562,273	683,335	379,946	27.80	13,667
1984	1,465,394.56	758,283	921,547	543,848	28.47	19,102
1985	4,994,478.19	2,526,856	3,070,907	1,923,571	29.15	65,989
1986	3,760,128.16	1,859,045	2,259,311	1,500,817	29.83	50,312
1987	7,810,103.01	3,768,687	4,580,113	3,229,990	30.53	105,797
1988	12,613,540.98	5,936,941	7,215,208	5,398,333	31.23	172,857
1989	8,518,854.59	3,907,087	4,748,312	3,770,543	31.94	118,051
1990	3,824,358.46	1,707,347	2,074,951	1,749,407	32.66	53,564
1991	9,383,603.31	4,074,736	4,952,057	4,431,546	33.38	132,761
1992	22,932,025.12	9,670,206	11,752,273	11,179,752	34.12	327,660
1993	20,563,795.88	8,413,677	10,225,204	10,338,592	34.86	296,575
1994	2,850,922.77	1,130,220	1,373,565	1,477,358	35.61	41,487
1995	8,814,408.17	3,382,353	4,110,599	4,703,809	36.36	129,368
1996	13,700,241.07	5,080,734	6,174,653	7,525,588	37.12	202,737
1997	4,082,468.99	1,460,707	1,775,208	2,307,261	37.89	60,894
1998	11,921,004.49	4,109,766	4,994,629	6,926,375	38.66	179,161
1999	3,045,008.75	1,009,512	1,226,867	1,818,142	39.44	46,099
2000	17,027,648.02	5,417,176	6,583,534	10,444,114	40.23	259,610
2001	18,303,709.11	5,574,944	6,775,271	11,528,438	41.03	280,976

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 362.00 STATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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 59-R2						
2002	18,319,390.49	5,331,309	6,479,179	11,840,211	41.83	283,055
2003	6,456,894.35	1,791,530	2,177,260	4,279,634	42.63	100,390
2004	9,636,146.42	2,539,703	3,086,520	6,549,626	43.45	150,739
2005	23,229,020.67	5,799,357	7,048,001	16,181,020	44.27	365,508
2006	12,003,909.69	2,830,042	3,439,371	8,564,539	45.09	189,943
2007	20,978,565.96	4,650,738	5,652,076	15,326,490	45.92	333,765
2008	18,254,158.45	3,787,008	4,602,379	13,651,779	46.76	291,954
2009	10,498,632.68	2,028,546	2,465,307	8,033,326	47.60	168,767
2010	9,165,261.20	1,638,840	1,991,694	7,173,567	48.45	148,061
2011	17,334,459.62	2,849,959	3,463,576	13,870,884	49.30	281,357
2012	14,550,323.80	2,180,075	2,649,461	11,900,863	50.16	237,258
2013	12,750,375.35	1,724,488	2,095,783	10,654,592	51.02	208,832
2014	12,134,599.40	1,462,341	1,777,194	10,357,405	51.89	199,603
2015	15,992,452.15	1,691,362	2,055,525	13,936,927	52.76	264,157
2016	17,165,702.51	1,559,504	1,895,276	15,270,427	53.64	284,684
2017	11,344,632.05	861,398	1,046,863	10,297,769	54.52	188,881
2018	7,845,797.70	477,417	580,208	7,265,590	55.41	131,124
2019	17,699,757.87	809,941	984,327	16,715,431	56.30	296,899
2020	33,445,177.55	1,020,412	1,240,115	32,205,063	57.20	563,026
2021	21,983,799.16	335,253	407,435	21,576,364	58.10	371,366
2022	8,485,872.91	33,095	40,221	8,445,652	58.77	143,707
	576,435,754.65	168,524,395	204,775,573	371,660,182		8,528,787

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 43.6 1.48

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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 50-R1.5						
1943	518,330.43	456,027	518,330			
1944	27,731.01	24,254	27,731			
1945	45,609.75	39,644	45,610			
1946	104,776.11	90,485	104,776			
1947	147,075.56	126,191	147,076			
1948	179,644.52	153,129	179,645			
1949	244,312.55	206,835	244,313			
1950	53,507.38	44,989	53,507			
1951	312,026.81	260,480	312,027			
1952	62,979.05	52,197	62,979			
1953	356,467.76	293,302	356,468			
1954	396,276.34	323,599	396,276			
1955	687,280.19	556,834	687,280			
1956	673,323.27	541,217	673,323			
1957	859,979.47	685,576	859,979			
1958	847,680.51	670,176	842,261	5,420	10.47	518
1959	972,266.83	762,063	957,743	14,524	10.81	1,344
1960	1,112,015.33	863,814	1,085,621	26,394	11.16	2,365
1961	1,305,275.31	1,004,540	1,262,482	42,793	11.52	3,715
1962	1,812,890.63	1,381,785	1,736,595	76,296	11.89	6,417
1963	2,471,892.67	1,865,785	2,344,874	127,019	12.26	10,360
1964	2,687,870.13	2,007,839	2,523,404	164,466	12.65	13,001
1965	3,103,040.04	2,293,767	2,882,752	220,288	13.04	16,893
1966	3,192,813.17	2,334,585	2,934,051	258,762	13.44	19,253
1967	3,540,185.31	2,558,846	3,215,897	324,288	13.86	23,397
1968	3,727,424.65	2,662,872	3,346,634	380,791	14.28	26,666
1969	3,963,086.73	2,797,147	3,515,388	447,699	14.71	30,435
1970	2,732,488.00	1,904,544	2,393,586	338,902	15.15	22,370
1971	3,559,071.95	2,447,930	3,076,500	482,572	15.61	30,914
1972	4,945,858.49	3,356,260	4,218,068	727,790	16.07	45,289
1973	4,179,453.24	2,796,054	3,514,014	665,439	16.55	40,208
1974	4,287,479.69	2,827,164	3,553,113	734,367	17.03	43,122
1975	2,899,029.13	1,882,630	2,366,045	532,984	17.53	30,404
1976	3,057,338.46	1,954,251	2,456,056	601,282	18.04	33,330
1977	2,641,029.48	1,661,208	2,087,767	553,262	18.55	29,825
1978	3,387,995.75	2,095,137	2,633,119	754,877	19.08	39,564
1979	4,422,966.86	2,687,395	3,377,454	1,045,513	19.62	53,288
1980	4,474,883.28	2,670,610	3,356,359	1,118,524	20.16	55,482
1981	4,264,002.17	2,497,000	3,138,170	1,125,832	20.72	54,336
1982	3,559,592.00	2,043,918	2,568,748	990,844	21.29	46,540
1983	3,960,060.86	2,227,930	2,800,010	1,160,051	21.87	53,043
1984	4,205,692.84	2,317,337	2,912,374	1,293,319	22.45	57,609
1985	7,333,655.63	3,952,840	4,967,836	2,365,820	23.05	102,639
1986	8,105,397.08	4,271,544	5,368,375	2,737,022	23.65	115,730

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 364.00 POLES, TOWERS AND FIXTURES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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 50-R1.5						
1987	8,306,135.60	4,274,337	5,371,886	2,934,250	24.27	120,900
1988	11,253,232.65	5,651,373	7,102,512	4,150,721	24.89	166,763
1989	9,730,091.11	4,763,853	5,987,098	3,742,993	25.52	146,669
1990	10,542,772.97	5,026,794	6,317,556	4,225,217	26.16	161,514
1991	13,323,073.23	6,179,241	7,765,924	5,557,149	26.81	207,279
1992	11,507,027.50	5,185,067	6,516,469	4,990,558	27.47	181,673
1993	12,140,913.13	5,310,435	6,674,029	5,466,884	28.13	194,344
1994	13,157,892.44	5,578,946	7,011,487	6,146,405	28.80	213,417
1995	14,222,528.82	5,836,926	7,335,710	6,886,819	29.48	233,610
1996	16,892,107.13	6,699,410	8,419,660	8,472,447	30.17	280,824
1997	19,690,631.81	7,533,636	9,468,095	10,222,537	30.87	331,148
1998	28,995,071.97	10,687,584	13,431,902	15,563,170	31.57	492,973
1999	11,689,108.37	4,144,958	5,209,285	6,479,823	32.27	200,800
2000	13,955,538.02	4,747,674	5,966,764	7,988,774	32.99	242,157
2001	20,249,414.80	6,597,259	8,291,279	11,958,136	33.71	354,736
2002	11,154,845.23	3,473,619	4,365,562	6,789,283	34.43	197,191
2003	9,995,860.22	2,966,771	3,728,568	6,267,292	35.16	178,251
2004	18,235,652.41	5,142,454	6,462,914	11,772,738	35.90	327,931
2005	15,289,406.88	4,085,330	5,134,346	10,155,061	36.64	277,158
2006	19,666,405.53	4,959,867	6,233,443	13,432,963	37.39	359,266
2007	8,148,283.90	1,932,773	2,429,063	5,719,221	38.14	149,953
2008	17,894,516.95	3,972,583	4,992,648	12,901,869	38.90	331,668
2009	15,124,516.21	3,127,750	3,930,882	11,193,634	39.66	282,240
2010	17,626,564.15	3,373,724	4,240,017	13,386,547	40.43	331,104
2011	14,498,040.91	2,551,655	3,206,860	11,291,181	41.20	274,058
2012	120,393,610.65	19,311,135	24,269,778	96,123,833	41.98	2,289,753
2013	12,323,717.89	1,784,474	2,242,685	10,081,033	42.76	235,758
2014	16,532,261.97	2,132,662	2,680,279	13,851,983	43.55	318,071
2015	13,583,196.43	1,537,618	1,932,442	11,650,754	44.34	262,759
2016	17,736,099.67	1,727,496	2,171,076	15,565,024	45.13	344,893
2017	13,955,857.64	1,136,007	1,427,707	12,528,151	45.93	272,766
2018	30,896,105.64	2,014,426	2,531,683	28,364,423	46.74	606,855
2019	23,161,784.51	1,139,560	1,432,172	21,729,613	47.54	457,081
2020	30,907,446.05	1,013,764	1,274,074	29,633,372	48.36	612,766
2021	34,820,666.18	571,059	717,693	34,102,973	49.18	693,432
2022	17,486,666.14	73,444	92,303	17,394,363	49.79	349,355
	800,508,801.13	224,897,394	282,470,467	518,038,334		13,689,173

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 37.8 1.71

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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 36-R0.5						
1943	10,402.52	10,403	10,403			
1944	924.81	925	925			
1945	1,714.90	1,715	1,715			
1946	3,638.38	3,638	3,638			
1947	5,988.08	5,988	5,988			
1948	7,767.48	7,767	7,767			
1949	11,329.42	11,329	11,329			
1950	13,600.38	13,464	7,988	5,612	0.36	5,612
1951	20,591.36	20,305	12,046	8,545	0.50	8,545
1952	24,516.40	23,849	14,149	10,367	0.98	10,367
1953	38,977.55	37,397	22,186	16,792	1.46	11,501
1954	57,880.98	54,762	32,488	25,393	1.94	13,089
1955	95,740.58	89,358	53,013	42,728	2.40	17,803
1956	117,878.53	108,514	64,377	53,502	2.86	18,707
1957	200,126.96	181,781	107,844	92,283	3.30	27,965
1958	178,090.78	159,589	94,678	83,413	3.74	22,303
1959	220,507.11	194,966	115,666	104,841	4.17	25,142
1960	296,495.72	258,776	153,522	142,974	4.58	31,217
1961	368,640.81	317,440	188,325	180,316	5.00	36,063
1962	464,784.88	395,067	234,378	230,407	5.40	42,668
1963	436,839.96	366,338	217,334	219,506	5.81	37,781
1964	709,307.07	586,952	348,216	361,091	6.21	58,147
1965	1,086,615.79	887,407	526,465	560,151	6.60	84,871
1966	1,380,735.93	1,112,266	659,865	720,871	7.00	102,982
1967	1,529,621.78	1,215,621	721,181	808,441	7.39	109,397
1968	1,609,358.30	1,261,109	748,168	861,190	7.79	110,551
1969	1,532,212.93	1,183,634	702,205	830,008	8.19	101,344
1970	1,358,039.91	1,033,998	613,431	744,609	8.59	86,683
1971	1,557,032.00	1,168,210	693,054	863,978	8.99	96,104
1972	1,690,211.83	1,249,354	741,194	949,018	9.39	101,067
1973	1,598,057.98	1,163,035	689,984	908,074	9.80	92,661
1974	1,732,237.29	1,240,957	736,212	996,025	10.21	97,554
1975	1,436,619.18	1,012,414	600,626	835,993	10.63	78,645
1976	1,467,686.50	1,017,195	603,463	864,224	11.05	78,210
1977	1,252,501.70	853,442	506,314	746,188	11.47	65,056
1978	1,852,746.61	1,240,303	735,824	1,116,923	11.90	93,859
1979	2,527,341.61	1,661,019	985,419	1,541,923	12.34	124,953
1980	2,812,297.46	1,813,932	1,076,136	1,736,161	12.78	135,850
1981	2,270,560.69	1,436,765	852,378	1,418,183	13.22	107,276
1982	1,783,243.89	1,105,611	655,917	1,127,327	13.68	82,407
1983	2,172,390.28	1,319,727	782,943	1,389,447	14.13	98,333
1984	2,141,477.58	1,272,980	755,210	1,386,268	14.60	94,950
1985	3,028,299.10	1,760,623	1,044,510	1,983,789	15.07	131,638
1986	4,719,718.20	2,682,357	1,591,340	3,128,378	15.54	201,311

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 365.00 OVERHEAD CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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 36-R0.5						
1987	5,410,962.84	3,001,569	1,780,716	3,630,247	16.03	226,466
1988	8,215,086.93	4,445,266	2,637,206	5,577,881	16.52	337,644
1989	7,968,366.11	4,203,313	2,493,664	5,474,702	17.01	321,852
1990	8,164,761.04	4,193,503	2,487,845	5,676,916	17.51	324,210
1991	12,430,293.49	6,208,186	3,683,079	8,747,214	18.02	485,417
1992	10,923,485.90	5,297,891	3,143,036	7,780,450	18.54	419,657
1993	10,292,380.97	4,843,183	2,873,275	7,419,106	19.06	389,250
1994	10,709,226.48	4,881,587	2,896,058	7,813,168	19.59	398,835
1995	11,395,548.31	5,026,690	2,982,142	8,413,406	20.12	418,161
1996	9,133,681.67	3,891,953	2,308,946	6,824,736	20.66	330,336
1997	11,394,897.96	4,684,557	2,779,168	8,615,730	21.20	406,402
1998	29,586,356.82	11,711,168	6,947,787	22,638,570	21.75	1,040,854
1999	12,777,753.29	4,859,124	2,882,732	9,895,021	22.31	443,524
2000	13,324,321.44	4,859,647	2,883,042	10,441,279	22.87	456,549
2001	17,173,927.65	5,991,812	3,554,712	13,619,216	23.44	581,025
2002	11,363,543.65	3,784,742	2,245,342	9,118,202	24.01	379,767
2003	13,893,803.71	4,407,392	2,614,737	11,279,067	24.58	458,872
2004	16,920,136.65	5,094,822	3,022,563	13,897,574	25.16	552,368
2005	16,333,387.55	4,650,442	2,758,929	13,574,459	25.75	527,163
2006	28,022,557.77	7,527,139	4,465,563	23,556,995	26.33	894,683
2007	16,680,337.98	4,207,115	2,495,920	14,184,418	26.92	526,910
2008	22,397,314.85	5,281,959	3,133,584	19,263,731	27.51	700,245
2009	25,797,620.63	5,661,030	3,358,472	22,439,149	28.10	798,546
2010	25,985,294.99	5,269,298	3,126,072	22,859,223	28.70	796,489
2011	22,938,462.36	4,269,077	2,532,680	20,405,782	29.30	696,443
2012	184,032,142.84	31,182,406	18,499,326	165,532,817	29.90	5,536,215
2013	25,273,466.89	3,861,280	2,290,749	22,982,718	30.50	753,532
2014	38,583,438.90	5,251,592	3,115,568	35,467,871	31.10	1,140,446
2015	33,168,713.38	3,952,716	2,344,995	30,823,718	31.71	972,050
2016	39,048,910.80	4,002,513	2,374,538	36,674,373	32.31	1,135,078
2017	27,098,380.45	2,318,537	1,375,499	25,722,881	32.92	781,375
2018	63,560,808.59	4,360,907	2,587,159	60,973,650	33.53	1,818,480
2019	62,779,960.31	3,226,262	1,914,017	60,865,943	34.15	1,782,312
2020	73,508,527.11	2,531,634	1,501,922	72,006,605	34.76	2,071,536
2021	34,355,280.94	591,598	350,972	34,004,309	35.38	961,117
2022	16,318,095.18	72,452	42,983	16,275,112	35.84	454,105
	1,022,785,987.63	221,146,644	131,214,812	891,571,176		32,960,526

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 27.0 3.22

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 365.10 OVERHEAD CONDUCTORS AND DEVICES - CLEARING

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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-R5						
1943	24,873.32	23,502	24,873			
1944	3,111.70	2,929	3,112			
1945	19,865.74	18,617	19,866			
1946	52,641.58	49,115	52,642			
1947	59,871.67	55,587	59,872			
1948	51,228.34	47,313	51,228			
1949	51,058.62	46,887	51,059			
1950	39,217.14	35,800	39,151	66	6.10	11
1951	53,958.21	48,933	53,514	444	6.52	68
1952	60,893.60	54,847	59,981	913	6.95	131
1953	74,662.42	66,759	73,009	1,653	7.41	223
1954	58,860.75	52,218	57,106	1,755	7.90	222
1955	88,437.81	77,813	85,097	3,341	8.41	397
1956	68,406.96	59,660	65,245	3,162	8.95	353
1957	70,244.19	60,701	66,383	3,861	9.51	406
1958	199,742.23	170,921	186,922	12,820	10.10	1,269
1959	360,047.08	304,909	333,453	26,594	10.72	2,481
1960	278,974.78	233,700	255,578	23,397	11.36	2,060
1961	322,865.21	267,378	292,408	30,457	12.03	2,532
1962	508,033.67	415,719	454,636	53,398	12.72	4,198
1963	443,089.37	358,078	391,599	51,490	13.43	3,834
1964	728,905.90	581,353	635,776	93,130	14.17	6,572
1965	396,960.48	312,293	341,528	55,432	14.93	3,713
1966	480,839.92	372,925	407,836	73,004	15.71	4,647
1967	825,043.56	630,449	689,468	135,576	16.51	8,212
1968	773,237.43	581,807	636,272	136,965	17.33	7,903
1969	1,166,188.75	863,644	944,493	221,696	18.16	12,208
1970	783,686.77	570,861	624,302	159,385	19.01	8,384
1971	735,036.97	526,389	575,666	159,371	19.87	8,021
1972	876,066.33	616,374	674,075	201,991	20.75	9,735
1973	868,262.14	599,848	656,002	212,260	21.64	9,809
1974	728,678.86	494,044	540,293	188,386	22.54	8,358
1975	371,872.24	247,295	270,445	101,427	23.45	4,325
1976	373,375.13	243,332	266,111	107,264	24.38	4,400
1977	380,804.83	243,117	265,876	114,929	25.31	4,541
1978	449,398.95	280,874	307,168	142,231	26.25	5,418
1979	1,078,829.48	659,629	721,379	357,450	27.20	13,142
1980	896,678.78	535,954	586,127	310,552	28.16	11,028
1981	580,411.94	338,961	370,692	209,720	29.12	7,202
1982	466,939.55	266,221	291,143	175,797	30.09	5,842
1983	459,402.38	255,492	279,410	179,992	31.07	5,793
1984	593,622.00	321,826	351,953	241,669	32.05	7,540
1985	399,778.74	211,083	230,843	168,936	33.04	5,113
1986	964,510.61	495,623	542,020	422,491	34.03	12,415

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 365.10 OVERHEAD CONDUCTORS AND DEVICES - CLEARING

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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-R5						
1987	608,978.33	304,313	332,801	276,177	35.02	7,886
1988	842,037.99	408,868	447,144	394,894	36.01	10,966
1989	749,403.12	353,186	386,249	363,154	37.01	9,812
1990	460,983.61	210,734	230,462	230,522	38.00	6,066
1991	852,903.84	377,717	413,077	439,827	39.00	11,278
1992	1,193,905.91	511,672	559,572	634,334	40.00	15,858
1993	961,226.97	398,227	435,507	525,720	41.00	12,822
1994	805,378.47	322,151	352,309	453,069	42.00	10,787
1995	809,248.56	312,135	341,355	467,894	43.00	10,881
1996	1,376,653.51	511,330	559,198	817,456	44.00	18,579
1997	1,079,711.61	385,608	421,706	658,006	45.00	14,622
1998	2,756,678.40	945,155	1,033,635	1,723,043	46.00	37,457
1999	894,038.69	293,754	321,253	572,786	47.00	12,187
2000	362,847.59	114,039	124,715	238,133	48.00	4,961
2001	425,381.90	127,615	139,562	285,820	49.00	5,833
2002	344,701.69	98,485	107,705	236,997	50.00	4,740
2003	86,260.22	23,414	25,606	60,654	51.00	1,189
2004	4,767,803.92	1,225,993	1,340,763	3,427,041	52.00	65,905
2006	2,902,305.84	663,380	725,482	2,176,824	54.00	40,312
2007	831,389.68	178,158	194,836	636,554	55.00	11,574
2008	4,814,086.85	962,817	1,052,950	3,761,137	56.00	67,163
2009	20,770,175.05	3,857,229	4,218,319	16,551,856	57.00	290,383
2010	6,039,112.92	1,035,285	1,132,202	4,906,911	58.00	84,602
2011	9,667,920.50	1,519,217	1,661,437	8,006,484	59.00	135,703
2013	42,121,674.01	5,415,584	5,922,558	36,199,116	61.00	593,428
2014	11,408,553.65	1,303,884	1,425,945	9,982,609	62.00	161,010
2015	3,880,974.44	388,097	424,428	3,456,546	63.00	54,866
2016	963,440.79	82,577	90,307	873,134	64.00	13,643
2017	19,198,961.02	1,371,382	1,499,763	17,699,198	65.00	272,295
2018	15,293,638.32	873,878	955,685	14,337,953	66.00	217,242
2019	19,781,026.78	847,815	927,182	18,853,845	67.00	281,401
2020	8,821,136.34	252,020	275,613	8,545,523	68.00	125,669
2021	3,563,920.80	50,928	55,696	3,508,225	69.00	50,844
2022	489,207.62	1,746	1,909	487,299	69.75	6,986
	208,194,285.07	38,429,173	42,022,543	166,171,742		2,861,456

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 58.1 1.37

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 366.00 UNDERGROUND CONDUIT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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 80-R4						
1943	855,709.64	725,428	855,710			
1945	771.55	644	772			
1946	3,243.64	2,687	3,244			
1947	7,402.92	6,081	7,403			
1948	6,289.28	5,120	6,289			
1949	18,376.23	14,825	18,376			
1951	44,977.80	35,589	44,978			
1952	21,626.23	16,936	21,626			
1953	47,175.46	36,561	47,175			
1954	83,513.99	64,023	83,514			
1955	130,712.78	99,113	130,713			
1956	158,683.97	118,953	158,684			
1957	598,401.90	443,416	598,402			
1958	394,718.75	289,033	394,719			
1959	227,682.12	164,701	227,682			
1960	236,605.65	169,026	236,606			
1961	215,124.31	151,716	213,411	1,713	23.58	73
1962	340,020.27	236,654	332,888	7,132	24.32	293
1963	290,942.05	199,804	281,053	9,889	25.06	395
1964	144,939.67	98,160	138,076	6,864	25.82	266
1965	170,377.52	113,747	160,002	10,376	26.59	390
1966	456,917.28	300,652	422,911	34,006	27.36	1,243
1967	406,627.51	263,543	370,712	35,916	28.15	1,276
1968	743,684.24	474,656	667,673	76,011	28.94	2,627
1969	536,978.03	337,356	474,540	62,438	29.74	2,099
1970	639,893.38	395,454	556,264	83,629	30.56	2,737
1971	586,624.19	356,521	501,499	85,125	31.38	2,713
1972	361,174.47	215,758	303,495	57,679	32.21	1,791
1973	2,340,769.06	1,373,751	1,932,381	408,388	33.05	12,357
1974	2,045,828.37	1,178,909	1,658,307	387,521	33.90	11,431
1975	1,301,649.23	736,239	1,035,627	266,022	34.75	7,655
1976	2,097,906.32	1,163,814	1,637,074	460,832	35.62	12,937
1977	878,855.50	477,992	672,365	206,490	36.49	5,659
1978	1,333,680.21	710,692	999,692	333,988	37.37	8,937
1979	1,831,735.09	955,708	1,344,342	487,393	38.26	12,739
1980	1,224,518.54	625,264	879,525	344,994	39.15	8,812
1981	1,443,941.73	721,076	1,014,298	429,644	40.05	10,728
1982	1,263,797.26	616,733	867,525	396,272	40.96	9,675
1983	1,430,193.08	681,487	958,611	471,582	41.88	11,260
1984	1,502,892.79	698,845	983,027	519,866	42.80	12,146
1985	2,623,921.12	1,189,948	1,673,835	950,086	43.72	21,731
1986	2,777,299.27	1,226,872	1,725,774	1,051,525	44.66	23,545
1987	2,721,121.19	1,170,409	1,646,351	1,074,770	45.59	23,575
1988	4,172,806.70	1,745,819	2,455,749	1,717,058	46.53	36,902

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 366.00 UNDERGROUND CONDUIT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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 80-R4						
1989	3,608,566.68	1,466,882	2,063,383	1,545,184	47.48	32,544
1990	2,806,242.95	1,107,400	1,557,719	1,248,524	48.43	25,780
1991	4,184,770.49	1,601,177	2,252,289	1,932,481	49.39	39,127
1992	3,772,176.04	1,398,044	1,966,553	1,805,623	50.35	35,861
1993	4,154,113.81	1,489,748	2,095,548	2,058,566	51.31	40,120
1994	6,709,942.54	2,324,995	3,270,444	3,439,499	52.28	65,790
1995	12,259,729.87	4,100,880	5,768,485	6,491,245	53.24	121,924
1996	6,348,756.53	2,045,887	2,877,838	3,470,919	54.22	64,015
1997	4,943,683.65	1,533,135	2,156,578	2,787,106	55.19	50,500
1998	6,711,752.47	1,999,297	2,812,302	3,899,450	56.17	69,422
1999	721,569.22	206,095	289,903	431,666	57.15	7,553
2000	2,367,920.00	647,342	910,581	1,457,339	58.13	25,070
2001	5,035,125.19	1,314,772	1,849,418	3,185,707	59.11	53,895
2002	5,684,343.51	1,413,980	1,988,968	3,695,376	60.10	61,487
2003	1,246,762.05	294,710	414,553	832,209	61.09	13,623
2004	112,778.08	25,276	35,554	77,224	62.07	1,244
2005	308,204.08	65,262	91,801	216,403	63.06	3,432
2006	358,348.31	71,447	100,501	257,847	64.05	4,026
2007	188,804.71	35,284	49,632	139,173	65.05	2,139
2008	398,436.85	69,527	97,800	300,637	66.04	4,552
2009	835,666.78	135,478	190,569	645,098	67.03	9,624
2010	383,734.62	57,414	80,761	302,974	68.03	4,454
2011	792,629.08	108,788	153,026	639,603	69.02	9,267
2012	802,487.74	100,110	140,819	661,669	70.02	9,450
2013	116,838.60	13,115	18,448	98,391	71.02	1,385
2014	482,443.64	48,186	67,781	414,663	72.01	5,758
2015	88,873.43	7,766	10,924	77,949	73.01	1,068
2016	448,671.17	33,596	47,258	401,413	74.01	5,424
2017	174,207.30	10,867	15,286	158,921	75.01	2,119
2018	920,680.92	46,034	64,753	855,928	76.00	11,262
2019	920,275.07	34,510	48,543	871,732	77.00	11,321
2020	1,450,617.90	36,265	51,012	1,399,606	78.00	17,944
2021	2,652,057.86	33,151	46,632	2,605,426	79.00	32,980
2022	2,328,786.72	7,266	10,221	2,318,566	79.75	29,073
	123,040,108.15	44,493,401	62,338,783	60,701,325		1,119,225

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 54.2 0.91

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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 47-R1.5						
1944	1,479.60	1,331	1,480			
1945	336.40	301	336			
1947	724.48	640	724			
1948	1,118.77	983	1,119			
1949	12,922.18	11,278	12,922			
1950	8,418.08	7,299	8,418			
1951	25,130.19	21,639	25,130			
1952	15,540.16	13,289	15,540			
1953	29,684.09	25,200	29,684			
1954	64,800.97	54,612	64,801			
1955	76,175.30	63,728	76,175			
1956	72,039.79	59,808	72,040			
1957	333,998.52	275,088	333,999			
1958	199,530.62	163,021	199,531			
1959	350,454.03	284,018	350,454			
1960	1,961.01	1,576	1,961			
1961	272,237.45	216,864	272,237			
1962	185,426.82	146,369	185,427			
1963	203,015.44	158,784	203,015			
1964	233,570.14	180,942	233,570			
1965	205,747.27	157,812	205,747			
1966	327,182.45	248,381	327,182			
1967	672,975.69	505,445	672,976			
1968	1,033,144.03	767,388	1,033,144			
1969	48,189.69	35,384	48,190			
1970	318,254.04	230,903	318,254			
1971	1,170,266.54	838,613	1,170,267			
1972	415,193.35	293,729	415,193			
1973	1,443,168.04	1,007,461	1,441,370	1,798	14.19	127
1974	1,304,050.10	897,852	1,284,553	19,497	14.64	1,332
1975	796,159.15	540,202	772,864	23,295	15.11	1,542
1976	1,165,093.43	778,877	1,114,336	50,757	15.58	3,258
1977	1,286,071.24	846,351	1,210,870	75,201	16.07	4,680
1978	2,116,435.72	1,370,286	1,960,462	155,974	16.57	9,413
1979	2,103,855.74	1,339,315	1,916,152	187,704	17.08	10,990
1980	2,020,852.95	1,264,104	1,808,548	212,305	17.60	12,063
1981	2,221,983.43	1,364,876	1,952,722	269,261	18.13	14,852
1982	2,209,205.30	1,331,643	1,905,175	304,030	18.67	16,284
1983	1,879,600.94	1,110,957	1,589,441	290,160	19.22	15,097
1984	2,153,507.84	1,247,204	1,784,369	369,139	19.78	18,662
1985	5,714,007.39	3,238,757	4,633,674	1,080,333	20.36	53,062
1986	4,934,874.94	2,736,240	3,914,726	1,020,149	20.94	48,718
1987	5,902,633.16	3,198,696	4,576,359	1,326,274	21.53	61,601
1988	10,326,006.67	5,461,838	7,814,226	2,511,781	22.14	113,450

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 367.00 UNDERGROUND CONDUCTORS AND DEVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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 47-R1.5						
1989	9,418,024.54	4,859,324	6,952,212	2,465,813	22.75	108,387
1990	8,239,301.22	4,142,473	5,926,617	2,312,684	23.37	98,960
1991	14,859,481.16	7,271,636	10,403,496	4,455,985	24.00	185,666
1992	11,671,186.17	5,552,450	7,943,864	3,727,322	24.64	151,271
1993	11,949,547.87	5,519,616	7,896,889	4,052,659	25.29	160,247
1994	6,991,262.22	3,131,177	4,479,760	2,511,502	25.95	96,782
1995	7,748,772.40	3,360,023	4,807,169	2,941,603	26.62	110,503
1996	9,692,868.50	4,064,801	5,815,492	3,877,376	27.29	142,080
1997	11,866,162.40	4,801,999	6,870,197	4,995,965	27.98	178,555
1998	16,747,829.67	6,531,654	9,344,807	7,403,023	28.67	258,215
1999	12,427,610.29	4,664,331	6,673,236	5,754,374	29.36	195,994
2000	11,461,051.98	4,128,386	5,906,463	5,554,589	30.07	184,722
2001	11,483,993.04	3,963,241	5,670,190	5,813,803	30.78	188,882
2002	9,096,178.89	2,999,829	4,291,841	4,804,338	31.50	152,519
2003	10,207,487.39	3,209,949	4,592,459	5,615,028	32.22	174,272
2004	10,418,758.11	3,114,584	4,456,021	5,962,737	32.95	180,963
2005	19,364,964.96	5,483,964	7,845,882	11,519,083	33.69	341,914
2006	19,143,322.32	5,119,882	7,324,991	11,818,331	34.43	343,257
2007	6,966,307.27	1,751,957	2,506,517	4,459,790	35.18	126,771
2008	22,132,577.35	5,212,886	7,458,052	14,674,525	35.93	408,420
2009	19,621,517.50	4,304,176	6,157,964	13,463,554	36.69	366,954
2010	16,709,783.81	3,395,261	4,857,584	11,852,200	37.45	316,481
2011	16,251,459.52	3,035,935	4,343,498	11,907,962	38.22	311,564
2012	47,166,270.39	8,038,547	11,500,711	35,665,559	38.99	914,736
2013	23,123,482.73	3,557,085	5,089,105	18,034,378	39.77	453,467
2014	30,885,983.42	4,238,484	6,063,979	24,822,004	40.55	612,133
2015	33,631,482.82	4,050,239	5,794,658	27,836,825	41.34	673,363
2016	30,824,311.10	3,187,234	4,559,961	26,264,350	42.14	623,264
2017	26,560,533.00	2,300,142	3,290,802	23,269,731	42.93	542,039
2018	28,152,807.37	1,952,679	2,793,689	25,359,118	43.74	579,770
2019	25,664,555.40	1,337,893	1,914,117	23,750,438	44.55	533,119
2020	27,383,309.50	955,404	1,366,892	26,016,418	45.36	573,554
2021	33,026,956.27	576,320	824,538	32,202,418	46.18	697,324
2022	11,834,790.62	52,902	75,687	11,759,104	46.79	251,317
	666,580,954.34	162,365,547	231,758,703	434,822,251		11,622,596

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 37.4 1.74

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 368.00 LINE TRANSFORMERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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 42-R1						
1944	154.52	147	155			
1946	27.81	26	28			
1959	81,102.32	67,933	81,102			
1961	142,056.24	116,621	142,056			
1962	141,209.64	114,750	141,210			
1963	171,158.65	137,579	171,159			
1964	188,344.80	149,779	186,469	1,876	8.60	218
1965	238,651.92	187,626	233,587	5,065	8.98	564
1966	266,089.83	206,789	257,445	8,645	9.36	924
1967	710,098.85	545,257	678,824	31,275	9.75	3,208
1968	1,820,535.26	1,381,003	1,719,297	101,238	10.14	9,984
1969	2,701,420.34	2,023,499	2,519,180	182,240	10.54	17,290
1970	1,648,595.41	1,218,790	1,517,348	131,247	10.95	11,986
1971	2,642,581.29	1,927,816	2,400,058	242,523	11.36	21,349
1972	2,652,212.42	1,907,710	2,375,027	277,185	11.79	23,510
1973	5,233,320.41	3,711,942	4,621,228	612,092	12.21	50,130
1974	7,040,228.09	4,919,782	6,124,943	915,285	12.65	72,355
1975	798,547.21	549,664	684,311	114,236	13.09	8,727
1976	3,563,208.06	2,414,501	3,005,963	557,245	13.54	41,155
1977	3,452,593.16	2,301,740	2,865,580	587,013	14.00	41,930
1978	3,606,639.20	2,364,080	2,943,191	663,448	14.47	45,850
1979	2,849,821.30	1,836,111	2,285,889	563,932	14.94	37,746
1980	1,182,098.46	748,103	931,360	250,738	15.42	16,261
1981	2,545,827.72	1,581,443	1,968,837	576,991	15.91	36,266
1982	3,755,240.47	2,288,030	2,848,511	906,729	16.41	55,255
1983	5,839,760.52	3,487,155	4,341,377	1,498,384	16.92	88,557
1984	7,877,111.04	4,608,110	5,736,923	2,140,188	17.43	122,788
1985	9,595,930.16	5,492,519	6,837,979	2,757,951	17.96	153,561
1986	12,957,405.11	7,253,037	9,029,758	3,927,647	18.49	212,420
1987	12,730,603.32	6,962,367	8,667,885	4,062,718	19.03	213,490
1988	12,894,254.17	6,883,082	8,569,178	4,325,076	19.58	220,893
1989	14,180,141.76	7,383,742	9,192,481	4,987,661	20.13	247,773
1990	10,509,046.84	5,329,558	6,635,099	3,873,948	20.70	187,147
1991	8,262,999.10	4,078,368	5,077,415	3,185,584	21.27	149,769
1992	7,459,790.71	3,578,909	4,455,607	3,004,184	21.85	137,491
1993	10,696,615.55	4,981,521	6,201,806	4,494,810	22.44	200,303
1994	11,796,151.25	5,325,137	6,629,595	5,166,556	23.04	224,243
1995	11,016,499.39	4,815,753	5,995,431	5,021,068	23.64	212,397
1996	9,360,872.30	3,956,092	4,925,186	4,435,686	24.25	182,915
1997	9,972,739.39	4,067,481	5,063,861	4,908,878	24.87	197,382
1998	7,149,278.72	2,808,666	3,496,683	3,652,596	25.50	143,239
1999	7,857,661.64	2,969,096	3,696,413	4,161,249	26.13	159,252
2000	17,225,109.92	6,246,169	7,776,245	9,448,865	26.77	352,965
2001	19,473,578.66	6,764,732	8,421,837	11,051,742	27.41	403,201

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 368.00 LINE TRANSFORMERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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 42-R1						
2002	19,282,681.66	6,399,922	7,967,662	11,315,020	28.06	403,244
2003	28,713,770.80	9,079,007	11,303,022	17,410,749	28.72	606,224
2004	42,320,098.05	12,716,343	15,831,368	26,488,730	29.38	901,591
2005	49,342,474.33	14,038,921	17,477,928	31,864,546	30.05	1,060,384
2006	32,440,162.90	8,712,455	10,846,679	21,593,484	30.72	702,913
2007	19,172,130.63	4,843,264	6,029,681	13,142,450	31.39	418,683
2008	46,339,428.40	10,956,031	13,639,846	32,699,582	32.07	1,019,631
2009	30,253,125.96	6,662,948	8,295,120	21,958,006	32.75	670,473
2010	30,900,646.35	6,297,861	7,840,600	23,060,046	33.44	689,595
2011	23,335,996.61	4,372,699	5,443,846	17,892,151	34.13	524,235
2012	83,580,706.08	14,288,122	17,788,174	65,792,532	34.82	1,889,504
2013	21,898,715.66	3,378,753	4,206,420	17,692,296	35.52	498,094
2014	22,451,934.79	3,089,835	3,846,728	18,605,207	36.22	513,672
2015	22,747,399.08	2,751,298	3,425,262	19,322,137	36.92	523,351
2016	22,909,847.22	2,383,770	2,967,704	19,942,143	37.63	529,953
2017	21,053,923.85	1,829,586	2,277,766	18,776,158	38.35	489,600
2018	27,035,898.13	1,886,024	2,348,029	24,687,869	39.07	631,888
2019	25,630,372.25	1,348,670	1,679,043	23,951,329	39.79	601,943
2020	27,118,139.54	955,643	1,189,740	25,928,400	40.52	639,891
2021	25,115,473.57	442,535	550,939	24,564,535	41.26	595,360
2022	12,426,954.11	56,170	69,930	12,357,024	41.81	295,552
	888,357,192.90	246,182,072	306,479,004	581,878,189		18,510,275

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 31.4 2.08

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 369.00 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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-R2						
1943	67,581.00	54,918	63,713	3,868	12.18	318
1944	3,807.57	3,073	3,565	243	12.54	19
1945	7,030.17	5,634	6,536	494	12.91	38
1946	17,623.72	14,020	16,265	1,359	13.29	102
1947	34,809.08	27,488	31,890	2,919	13.67	214
1948	49,872.10	39,084	45,343	4,529	14.06	322
1949	58,304.14	45,334	52,594	5,710	14.46	395
1950	66,738.34	51,471	59,714	7,024	14.87	472
1951	85,646.03	65,500	75,990	9,656	15.29	632
1952	104,246.22	79,034	91,692	12,554	15.72	799
1953	126,411.37	95,003	110,218	16,193	16.15	1,003
1954	198,541.26	147,838	171,515	27,026	16.60	1,628
1955	262,946.43	193,973	225,038	37,908	17.05	2,223
1956	309,887.04	226,410	262,670	47,217	17.51	2,697
1957	375,794.40	271,842	315,378	60,416	17.98	3,360
1958	417,749.02	299,108	347,011	70,738	18.46	3,832
1959	485,106.33	343,678	398,719	86,387	18.95	4,559
1960	596,736.07	418,175	485,147	111,589	19.45	5,737
1961	632,912.06	438,557	508,793	124,119	19.96	6,218
1962	769,583.60	527,226	611,663	157,921	20.47	7,715
1963	875,586.55	592,702	687,625	187,962	21.00	8,951
1964	1,017,645.86	680,418	789,389	228,257	21.54	10,597
1965	1,171,978.00	773,869	897,806	274,172	22.08	12,417
1966	1,423,842.39	928,132	1,076,775	347,067	22.63	15,337
1967	1,765,294.51	1,135,226	1,317,036	448,259	23.20	19,322
1968	1,952,415.65	1,238,437	1,436,776	515,640	23.77	21,693
1969	2,239,277.58	1,400,399	1,624,677	614,601	24.35	25,240
1970	2,280,878.02	1,406,070	1,631,256	649,622	24.93	26,058
1971	2,665,204.26	1,618,392	1,877,582	787,622	25.53	30,851
1972	3,360,936.34	2,009,336	2,331,137	1,029,799	26.14	39,396
1973	4,137,939.06	2,435,012	2,824,986	1,312,953	26.75	49,082
1974	3,866,451.73	2,238,366	2,596,847	1,269,605	27.37	46,387
1975	3,704,020.11	2,108,439	2,446,112	1,257,908	28.00	44,925
1976	4,146,448.36	2,319,440	2,690,905	1,455,543	28.64	50,822
1977	4,361,827.71	2,396,301	2,780,076	1,581,752	29.29	54,003
1978	4,971,070.85	2,681,296	3,110,713	1,860,358	29.94	62,136
1979	5,247,417.12	2,777,091	3,221,850	2,025,567	30.60	66,195
1980	4,969,448.06	2,578,746	2,991,740	1,977,708	31.27	63,246
1981	5,164,129.02	2,625,753	3,046,275	2,117,854	31.95	66,287
1982	5,438,489.82	2,708,368	3,142,121	2,296,369	32.63	70,376
1983	8,296,871.57	4,042,485	4,689,901	3,606,971	33.33	108,220
1984	10,997,329.33	5,239,788	6,078,955	4,918,374	34.03	144,531
1985	11,499,374.87	5,355,144	6,212,786	5,286,589	34.73	152,220
1986	12,419,667.32	5,648,092	6,552,651	5,867,016	35.44	165,548

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 369.00 SERVICES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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-R2						
1987	15,262,898.68	6,771,996	7,856,551	7,406,348	36.16	204,822
1988	12,612,004.35	5,454,187	6,327,691	6,284,313	36.89	170,353
1989	12,348,739.86	5,201,660	6,034,721	6,314,019	37.62	167,837
1990	9,526,721.16	3,904,527	4,529,849	4,996,872	38.36	130,263
1991	11,111,218.21	4,425,709	5,134,499	5,976,719	39.11	152,818
1992	14,395,576.83	5,567,777	6,459,473	7,936,104	39.86	199,099
1993	18,819,689.16	7,058,889	8,189,391	10,630,298	40.62	261,701
1994	14,348,551.73	5,211,824	6,046,513	8,302,039	41.39	200,581
1995	14,614,704.33	5,135,315	5,957,751	8,656,953	42.16	205,336
1996	14,518,851.55	4,927,408	5,716,547	8,802,305	42.94	204,991
1997	23,129,251.48	7,572,054	8,784,741	14,344,510	43.72	328,099
1998	24,326,739.93	7,668,518	8,896,654	15,430,086	44.51	346,666
1999	21,544,080.89	6,526,133	7,571,312	13,972,769	45.31	308,382
2000	16,849,796.15	4,896,888	5,681,139	11,168,657	46.11	242,218
2001	17,949,537.17	4,992,664	5,792,254	12,157,283	46.92	259,107
2002	16,162,630.10	4,294,249	4,981,985	11,180,645	47.73	234,248
2003	7,180,776.63	1,818,388	2,109,608	5,071,169	48.54	104,474
2004	584,724.91	140,603	163,121	421,604	49.37	8,540
2005	2,468,558.04	562,066	652,083	1,816,475	50.20	36,185
2006	2,271,531.89	488,198	566,384	1,705,148	51.03	33,415
2007	2,936,949.44	593,264	688,277	2,248,672	51.87	43,352
2008	5,730,380.84	1,083,500	1,257,026	4,473,355	52.71	84,867
2009	3,215,785.88	565,978	656,621	2,559,165	53.56	47,781
2010	4,868,354.09	793,152	920,178	3,948,176	54.41	72,563
2011	5,105,712.97	764,274	886,675	4,219,038	55.27	76,335
2012	12,449,442.37	1,698,851	1,970,927	10,478,515	56.13	186,683
2013	3,896,906.42	479,631	556,445	3,340,461	57.00	58,605
2014	5,721,290.39	627,568	728,075	4,993,215	57.87	86,283
2015	4,938,122.80	474,801	550,842	4,387,281	58.75	74,677
2016	7,068,957.71	584,037	677,572	6,391,386	59.63	107,184
2017	5,833,235.62	402,960	467,495	5,365,741	60.51	88,675
2018	6,886,941.92	381,399	442,481	6,444,461	61.40	104,959
2019	11,498,975.97	477,667	554,167	10,944,809	62.30	175,679
2020	6,839,660.56	190,485	220,991	6,618,670	63.19	104,742
2021	7,096,939.35	98,293	114,035	6,982,904	64.10	108,938
2022	3,303,773.56	11,695	13,568	3,290,206	64.77	50,798
	480,062,882.98	162,131,276	188,097,073	291,965,810		6,667,379

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 43.8 1.39

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 370.00 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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 23-R1						
1956	137.18	137	137			
1957	10.79	11	11			
1958	11.57	12	12			
1959	26.83	27	27			
1960	545.66	546	546			
1961	387.88	388	388			
1962	854.55	855	855			
1963	1,685.58	1,686	1,686			
1964	1,782.51	1,783	1,783			
1965	2,345.06	2,345	2,345			
1966	5,634.55	5,635	5,635			
1967	4,075.11	4,075	4,075			
1968	7,311.79	7,312	7,312			
1969	13,521.30	13,521	13,521			
1970	26,838.09	26,838	26,838			
1971	35,593.77	35,594	35,594			
1972	45,797.25	45,797	45,797			
1973	48,693.86	48,694	48,694			
1974	55,748.03	55,748	55,748			
1975	36,522.41	36,522	36,522			
1976	54,242.09	53,983	54,242			
1977	83,444.87	81,957	83,445			
1978	87,476.38	84,662	87,476			
1979	126,435.42	120,498	126,435			
1980	112,631.65	105,776	112,632			
1981	131,476.92	121,759	131,477			
1982	361,459.01	330,027	357,525	3,934	2.00	1,967
1983	812,600.77	731,341	792,276	20,325	2.30	8,837
1984	617,274.68	547,498	593,116	24,159	2.60	9,292
1985	628,705.11	549,161	594,917	33,788	2.91	11,611
1986	977,218.39	839,988	909,976	67,242	3.23	20,818
1987	718,713.75	607,155	657,743	60,971	3.57	17,079
1988	842,831.48	699,550	757,837	84,994	3.91	21,738
1989	845,939.26	689,254	746,683	99,256	4.26	23,300
1990	710,361.18	567,671	614,969	95,392	4.62	20,648
1991	961,399.49	752,401	815,091	146,308	5.00	29,262
1992	1,064,643.41	815,613	883,570	181,073	5.38	33,657
1993	1,117,261.48	836,494	906,191	211,070	5.78	36,517
1994	1,647,912.11	1,204,410	1,304,762	343,150	6.19	55,436
1995	1,468,815.31	1,046,046	1,133,203	335,612	6.62	50,697
1996	993,155.91	688,734	746,119	247,037	7.05	35,041
1997	1,528,949.80	1,030,375	1,116,226	412,724	7.50	55,030
1998	1,814,802.19	1,185,937	1,284,749	530,053	7.97	66,506
1999	1,482,592.52	937,903	1,016,049	466,544	8.45	55,212

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 370.00 METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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 23-R1						
2000	1,729,295.29	1,057,118	1,145,197	584,098	8.94	65,335
2001	2,371,587.14	1,397,173	1,513,586	858,001	9.45	90,794
2002	2,260,101.24	1,280,393	1,387,076	873,025	9.97	87,565
2003	3,865,324.80	2,099,026	2,273,917	1,591,408	10.51	151,418
2004	3,998,858.06	2,075,927	2,248,894	1,749,964	11.06	158,225
2005	3,655,181.57	1,806,939	1,957,494	1,697,688	11.63	145,975
2006	2,945,266.12	1,380,446	1,495,465	1,449,801	12.22	118,642
2007	1,259,844.26	557,620	604,081	655,763	12.82	51,152
2008	5,422,949.41	2,256,435	2,444,442	2,978,507	13.43	221,780
2009	6,120,668.52	2,381,736	2,580,183	3,540,486	14.05	251,992
2010	6,809,637.61	2,460,322	2,665,316	4,144,322	14.69	282,119
2011	4,757,194.98	1,584,336	1,716,343	3,040,852	15.34	198,230
2012	2,565,994.98	782,064	847,226	1,718,769	15.99	107,490
2013	14,145,199.72	3,899,124	4,224,000	9,921,200	16.66	595,510
2014	9,849,698.12	2,423,912	2,625,873	7,223,825	17.34	416,599
2015	18,811,224.26	4,073,006	4,412,369	14,398,855	18.02	799,049
2016	18,042,155.92	3,365,223	3,645,614	14,396,542	18.71	769,457
2017	9,921,082.63	1,552,848	1,682,231	8,238,852	19.40	424,683
2018	15,677,310.67	1,976,752	2,141,455	13,535,856	20.10	673,426
2019	12,507,244.92	1,190,940	1,290,170	11,217,075	20.81	539,023
2020	10,556,566.38	674,670	730,884	9,825,682	21.53	456,372
2021	9,451,359.42	304,050	329,383	9,121,976	22.26	409,792
2022	5,432,832.68	44,875	48,614	5,384,219	22.81	236,046
	191,634,445.65	55,540,654	60,124,048	131,510,398		7,803,322

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 16.9 4.07

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 370.10 SMART METERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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						
2013	389.34	169	194	195	11.30	17
2014	567.62	222	255	313	12.19	26
2015	5,296.53	1,825	2,094	3,203	13.11	244
2018	10,298.16	2,054	2,357	7,941	16.01	496
2019	134.64	20	23	112	17.00	7
2020	2,424.52	242	278	2,147	18.00	119
2021	3,907,628.70	195,381	224,187	3,683,442	19.00	193,865
2022	3,792,348.50	47,404	54,393	3,737,956	19.75	189,264
	7,719,088.01	247,317	283,781	7,435,307		384,038
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					19.4	4.98

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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-R2						
1943	66.87	67	67			
1954	19.90	20	20			
1960	40.63	41	41			
1961	18.04	18	18			
1963	3,115.07	3,115	3,115			
1964	4,198.55	4,199	4,199			
1965	4,504.15	4,504	4,504			
1966	4,064.24	4,064	4,064			
1967	1,796.52	1,785	1,344	453	0.19	453
1968	4,221.35	4,158	3,131	1,090	0.45	1,090
1969	1,190.48	1,163	876	314	0.70	314
1970	2,304.72	2,231	1,680	625	0.96	625
1972	947.92	900	678	270	1.51	179
1973	3,340.45	3,140	2,364	976	1.80	542
1974	327.60	305	230	98	2.08	47
1975	1,577.66	1,453	1,094	484	2.37	204
1977	818.52	738	556	263	2.95	89
1978	590.31	527	397	193	3.24	60
1979	937.94	827	623	315	3.54	89
1980	405.08	353	266	139	3.83	36
1981	7,063.15	6,091	4,587	2,476	4.13	600
1982	13,675.32	11,651	8,773	4,902	4.44	1,104
1983	11,814.80	9,940	7,485	4,330	4.76	910
1984	18,351.37	15,238	11,474	6,877	5.09	1,351
1985	10,804.04	8,849	6,663	4,141	5.43	763
1986	20,499.60	16,543	12,457	8,043	5.79	1,389
1987	19,706.22	15,660	11,792	7,914	6.16	1,285
1988	7,841.62	6,130	4,616	3,226	6.55	493
1989	81,063.54	62,257	46,880	34,184	6.96	4,911
1990	108,822.14	82,016	61,759	47,063	7.39	6,368
1991	60,861.55	44,977	33,868	26,994	7.83	3,448
1992	408,568.63	295,530	222,538	186,031	8.30	22,413
1993	791,251.67	559,676	421,443	369,809	8.78	42,119
1994	1,834,271.35	1,266,253	953,505	880,766	9.29	94,808
1995	2,740,992.09	1,843,783	1,388,393	1,352,599	9.82	137,739
1996	3,299,468.86	2,160,063	1,626,556	1,672,913	10.36	161,478
1997	1,091,860.75	694,423	522,910	568,951	10.92	52,102
1998	1,299,389.62	800,853	603,053	696,337	11.51	60,498
1999	147,337.19	87,862	66,161	81,176	12.11	6,703
2000	129,595.39	74,604	56,178	73,417	12.73	5,767
2001	195,203.88	108,207	81,481	113,723	13.37	8,506
2002	165,537.05	88,177	66,398	99,139	14.02	7,071
2003	337,897.01	172,439	129,849	208,048	14.69	14,163
2004	915,245.70	446,027	335,864	579,382	15.38	37,671

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 371.00 INSTALLATIONS ON CUSTOMERS' PREMISES

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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-R2						
2005	1,021,089.22	473,785	356,766	664,323	16.08	41,314
2006	956,449.49	420,838	316,896	639,553	16.80	38,069
2007	461,862.93	191,826	144,448	317,415	17.54	18,097
2008	1,102,084.30	430,551	324,210	777,874	18.28	42,553
2009	1,111,864.58	406,197	305,872	805,993	19.04	42,332
2010	874,557.26	296,764	223,467	651,090	19.82	32,850
2011	611,735.07	191,473	144,182	467,553	20.61	22,686
2012	965,245.32	276,707	208,364	756,881	21.40	35,368
2013	642,068.86	166,508	125,383	516,686	22.22	23,253
2014	501,671.10	116,388	87,642	414,029	23.04	17,970
2015	591,069.44	120,773	90,943	500,126	23.87	20,952
2016	654,963.37	115,274	86,803	568,160	24.72	22,984
2017	629,253.06	92,708	69,810	559,443	25.58	21,870
2018	653,242.55	77,520	58,374	594,869	26.44	22,499
2019	697,044.10	62,267	46,888	650,156	27.32	23,798
2020	771,380.73	46,283	34,851	736,530	28.20	26,118
2021	734,768.99	22,043	16,599	718,170	29.10	24,679
2022	333,444.74	2,558	1,926	331,519	29.77	11,136
	27,065,403.65	12,421,320	9,357,374	17,708,030		1,165,916

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 15.2 4.31

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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-R1.5						
1943	65,235.99	65,236	65,236			
1944	883.69	884	884			
1945	4,861.40	4,861	4,861			
1946	1,481.42	1,481	1,481			
1947	890.70	891	891			
1948	1,977.04	1,977	1,977			
1949	6,666.07	6,666	6,666			
1950	4,015.69	4,016	4,016			
1951	10,208.83	10,209	10,209			
1952	5,064.10	5,064	5,064			
1953	16,464.72	16,465	16,465			
1954	16,339.14	16,339	16,339			
1955	21,613.70	21,614	21,614			
1956	35,084.10	35,084	35,084			
1957	61,925.34	61,925	61,925			
1958	32,939.67	32,940	32,940			
1959	54,464.02	54,464	54,464			
1960	30,498.38	30,498	30,498			
1961	15,467.14	15,467	15,467			
1962	21,949.63	21,840	21,950			
1963	47,462.44	46,782	47,462			
1964	49,499.13	48,245	49,499			
1965	33,322.53	32,101	33,323			
1966	33,360.11	31,770	33,360			
1967	47,268.91	44,512	47,269			
1968	88,118.23	82,155	88,118			
1969	66,679.47	61,634	66,679			
1970	90,976.33	83,395	90,976			
1971	82,788.95	75,255	82,789			
1972	150,314.60	135,483	150,315			
1973	151,510.46	135,349	151,510			
1974	77,042.86	68,183	77,043			
1975	185,289.97	162,375	185,290			
1976	24,060.90	20,869	24,061			
1977	60,469.95	51,883	60,470			
1979	124,993.21	104,869	124,276	717	4.83	148
1980	121,569.09	100,781	119,431	2,138	5.13	417
1981	268,625.20	219,915	260,611	8,014	5.44	1,473
1982	417,609.11	337,428	399,871	17,738	5.76	3,080
1983	511,760.58	408,042	483,552	28,209	6.08	4,640
1984	576,550.02	453,168	537,029	39,521	6.42	6,156
1985	1,028,095.75	796,085	943,405	84,691	6.77	12,510
1986	1,818,286.09	1,386,134	1,642,646	175,640	7.13	24,634
1987	1,937,722.64	1,452,653	1,721,474	216,249	7.51	28,795

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 373.00 STREET LIGHTING AND SIGNAL SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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-R1.5						
1988	2,342,481.31	1,725,636	2,044,974	297,507	7.90	37,659
1989	1,842,202.33	1,331,912	1,578,390	263,812	8.31	31,746
1990	1,481,746.13	1,050,069	1,244,390	237,356	8.74	27,157
1991	1,663,148.52	1,154,225	1,367,821	295,328	9.18	32,171
1992	1,974,060.22	1,339,735	1,587,660	386,400	9.64	40,083
1993	2,794,666.51	1,851,942	2,194,654	600,013	10.12	59,290
1994	2,338,683.05	1,510,789	1,790,369	548,314	10.62	51,630
1995	2,367,068.64	1,488,886	1,764,413	602,656	11.13	54,147
1996	2,926,487.03	1,789,049	2,120,122	806,365	11.66	69,157
1997	3,687,969.94	2,186,966	2,591,676	1,096,294	12.21	89,787
1998	2,645,123.20	1,519,174	1,800,305	844,818	12.77	66,156
1999	6,361,652.96	3,530,717	4,184,096	2,177,557	13.35	163,113
2000	5,153,595.61	2,757,174	3,267,404	1,886,192	13.95	135,211
2001	11,618,135.16	5,979,506	7,086,046	4,532,089	14.56	311,270
2002	3,799,666.65	1,875,781	2,222,905	1,576,762	15.19	103,803
2003	4,229,674.63	1,997,802	2,367,506	1,862,169	15.83	117,635
2004	5,978,849.81	2,694,488	3,193,118	2,785,732	16.48	169,037
2005	9,059,082.94	3,880,277	4,598,344	4,460,739	17.15	260,101
2006	8,084,152.56	3,279,498	3,886,387	4,197,766	17.83	235,433
2007	6,333,562.35	2,423,664	2,872,176	3,461,386	18.52	186,900
2008	8,368,635.00	3,007,102	3,563,583	4,805,052	19.22	250,003
2009	8,369,701.86	2,806,612	3,325,991	5,043,711	19.94	252,944
2010	9,394,853.30	2,924,900	3,466,169	5,928,684	20.66	286,964
2011	8,227,742.63	2,361,362	2,798,345	5,429,398	21.39	253,829
2012	17,392,661.33	4,556,877	5,400,152	11,992,509	22.14	541,667
2013	9,457,279.22	2,241,375	2,656,154	6,801,125	22.89	297,122
2014	10,142,417.52	2,146,846	2,544,131	7,598,287	23.65	321,281
2015	10,908,564.61	2,032,593	2,408,735	8,499,830	24.41	348,211
2016	10,675,921.01	1,711,670	2,028,424	8,647,497	25.19	343,291
2017	10,150,906.16	1,363,571	1,615,907	8,534,999	25.97	328,648
2018	12,133,318.95	1,310,398	1,552,895	10,580,424	26.76	395,382
2019	11,447,514.92	931,026	1,103,317	10,344,198	27.56	375,334
2020	12,115,802.40	662,371	784,947	11,330,855	28.36	399,536
2021	12,571,001.29	343,565	407,143	12,163,858	29.18	416,856
2022	6,163,100.07	43,142	51,126	6,111,974	29.79	205,169
	252,602,837.12	80,557,687	95,298,265	157,304,572		7,339,576

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 21.4 2.91

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 373.30 STREET LIGHTING AND SIGNAL SYSTEMS - LED

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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						
2016	2,010.11	290	179	1,831	25.67	71
2017	52,161.71	6,312	3,904	48,258	26.37	1,830
2018	210,479.06	20,416	12,626	197,853	27.09	7,304
2019	347,583.13	25,488	15,763	331,820	27.80	11,936
2020	530,449.68	25,992	16,075	514,375	28.53	18,029
2021	898,226.97	22,159	13,705	884,522	29.26	30,230
2022	171,922.40	1,088	673	171,249	29.81	5,745
	2,212,833.06	101,745	62,925	2,149,908		75,145

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 28.6 3.40

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 389.20 LAND RIGHTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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 50-R3						
1962	375.80	329	232	144	6.28	23
1975	85.25	66	47	38	11.58	3
1978	12,259.10	9,010	6,357	5,902	13.25	445
2008	4.53	1	1	4	36.57	
	12,724.68	9,406	6,637	6,088		471

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 12.9 3.70

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 390.10 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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 50-S0						
1896	20,334.71	20,335	20,335			
1901	1,178.89	1,179	1,179			
1902	19,280.09	19,280	19,280			
1907	9,048.73	9,049	9,049			
1908	5,873.47	5,873	5,873			
1909	25.48	25	25			
1911	5,564.15	5,564	5,564			
1912	4,975.37	4,975	4,975			
1913	1,561.09	1,561	1,561			
1914	5,978.14	5,978	5,978			
1915	1,177.92	1,178	1,178			
1916	16.81	17	17			
1920	2,727.99	2,728	2,728			
1921	507.38	507	507			
1922	5,022.52	5,023	5,023			
1923	290.41	288	290			
1924	3,117.26	3,071	3,117			
1925	10,086.48	9,863	10,086			
1926	4,930.27	4,785	4,930			
1927	24.01	23	24			
1928	17,155.35	16,397	17,155			
1929	2,777.85	2,635	2,778			
1930	5,194.74	4,888	5,195			
1931	404.78	378	405			
1932	2,113.61	1,958	2,114			
1933	5,671.05	5,211	5,671			
1934	37.37	34	37			
1935	2,587.70	2,338	2,588			
1936	516.50	463	516			
1937	101.08	90	101			
1938	36,151.97	31,850	36,152			
1939	11,839.69	10,338	11,840			
1940	6,291.63	5,446	6,292			
1941	1,221.95	1,048	1,222			
1942	36.16	31	36			
1943	207.89	175	208			
1944	9.28	8	9			
1945	198.15	164	198			
1946	729.62	598	730			
1947	3,475.55	2,819	3,476			
1948	86.26	69	86			
1950	360.33	284	360			
1951	47,055.44	36,675	47,055			
1953	196,084.73	149,691	196,085			

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 390.10 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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 50-S0						
1954	277,496.09	209,565	277,496			
1955	55,263.17	41,293	55,263			
1956	385,682.84	285,020	385,683			
1957	135,112.43	98,740	135,112			
1958	401,890.13	290,406	401,890			
1959	293,114.11	209,342	293,114			
1960	332,575.36	234,798	332,575			
1961	101,033.69	70,481	101,034			
1962	845,523.84	582,735	845,524			
1963	158,430.31	107,859	158,430			
1964	345,547.61	232,277	345,548			
1965	512,049.84	339,796	512,050			
1966	1,295,563.33	848,594	1,295,563			
1967	829,161.89	535,970	822,490	6,672	17.68	377
1968	34,057.00	21,722	33,334	723	18.11	40
1969	160,671.70	101,062	155,088	5,584	18.55	301
1970	688,921.20	427,269	655,680	33,241	18.99	1,750
1971	13,152.69	8,042	12,341	812	19.43	42
1972	49,681.46	29,928	45,927	3,754	19.88	189
1973	129,784.26	77,014	118,184	11,600	20.33	571
1974	282,972.34	165,369	253,772	29,200	20.78	1,405
1975	6,196.97	3,566	5,472	725	21.23	34
1976	73,786.00	41,778	64,112	9,674	21.69	446
1977	69,701.78	38,824	59,579	10,123	22.15	457
1978	734,310.59	402,108	617,068	117,243	22.62	5,183
1979	1,733,086.43	932,747	1,431,377	301,709	23.09	13,067
1980	46,824.10	24,761	37,998	8,826	23.56	375
1981	1,109,790.67	576,425	884,572	225,219	24.03	9,372
1982	157,482.32	80,284	123,202	34,280	24.51	1,399
1983	2,806,873.77	1,403,437	2,153,690	653,184	25.00	26,127
1984	910,431.03	446,293	684,873	225,558	25.49	8,849
1985	1,373,551.20	659,854	1,012,600	360,951	25.98	13,893
1986	1,961,007.53	922,850	1,416,190	544,818	26.47	20,582
1987	2,669,142.85	1,228,873	1,885,807	783,336	26.98	29,034
1988	1,213,936.73	546,757	839,044	374,893	27.48	13,642
1989	1,033,980.98	455,158	698,478	335,503	27.99	11,987
1990	9,472,228.62	4,071,164	6,247,537	3,224,692	28.51	113,107
1991	3,009,822.38	1,262,320	1,937,134	1,072,688	29.03	36,951
1992	4,505,849.29	1,841,991	2,826,687	1,679,162	29.56	56,805
1993	1,840,089.36	732,724	1,124,426	715,663	30.09	23,784
1994	628,299.54	243,403	373,522	254,778	30.63	8,318
1995	1,669,728.31	628,820	964,976	704,752	31.17	22,610
1996	982,969.23	359,374	551,489	431,480	31.72	13,603
1997	1,036,801.85	367,443	563,872	472,930	32.28	14,651

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 390.10 STRUCTURES AND IMPROVEMENTS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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 50-S0						
1998	5,961,220.57	2,044,699	3,137,759	2,823,462	32.85	85,950
1999	3,022,068.28	1,002,118	1,537,833	1,484,235	33.42	44,412
2000	2,004,978.95	641,593	984,577	1,020,402	34.00	30,012
2001	1,474,180.92	454,343	697,227	776,954	34.59	22,462
2002	105,420.89	31,247	47,951	57,470	35.18	1,634
2003	1,502,238.20	426,936	655,169	847,069	35.79	23,668
2004	182,295.85	49,548	76,035	106,261	36.41	2,918
2005	573,065.06	148,653	228,120	344,945	37.03	9,315
2006	548,014.56	135,140	207,384	340,631	37.67	9,043
2007	588,061.14	137,489	210,988	377,073	38.31	9,843
2008	1,283,401.01	283,118	434,468	848,933	38.97	21,784
2009	1,684,296.03	348,986	535,548	1,148,748	39.64	28,980
2010	695,675.79	134,683	206,682	488,994	40.32	12,128
2011	319,124.14	57,315	87,955	231,169	41.02	5,636
2012	357,321.21	59,101	90,695	266,626	41.73	6,389
2013	301,120.40	45,409	69,684	231,436	42.46	5,451
2014	485,637.09	66,047	101,355	384,282	43.20	8,895
2015	2,253,194.42	271,735	417,000	1,836,194	43.97	41,760
2016	3,569,053.28	374,751	575,086	2,993,967	44.75	66,904
2017	2,582,483.34	229,841	352,710	2,229,773	45.55	48,952
2018	5,015,566.63	363,127	557,248	4,458,319	46.38	96,126
2019	2,761,243.35	152,973	234,750	2,526,493	47.23	53,493
2020	1,089,092.80	40,950	62,841	1,026,252	48.12	21,327
2021	922,548.37	17,897	27,465	895,083	49.03	18,256
2022	775,136.21	3,721	5,710	769,426	49.76	15,463
	86,872,045.16	30,084,546	45,724,071	41,147,974		1,139,752

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 36.1 1.31

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 390.20 STRUCTURES AND IMPROVEMENTS - CLEARING

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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-R2.5						
1911	635.15	610	635			
1918	1,445.23	1,348	1,445			
1919	434.89	404	435			
1922	354.72	326	355			
1923	2,387.58	2,186	2,388			
1924	1,371.98	1,251	1,372			
1925	297.60	270	298			
1928	37,146.79	33,375	37,147			
1929	6,594.85	5,902	6,595			
1930	1,013.98	904	1,014			
1932	641.56	567	642			
1935	30.82	27	31			
1938	3,135.51	2,702	3,136			
1939	36.23	31	36			
1940	26.03	22	26			
1941	1,544.37	1,312	1,544			
1943	261.37	220	261			
1945	902.02	750	902			
1947	366.80	301	367			
1948	73.34	60	73			
1950	63.06	51	63			
1951	5,503.20	4,401	5,503			
1953	23,265.45	18,326	23,265			
1954	35,571.54	27,790	35,572			
1955	11,647.81	9,024	11,648			
1956	62,011.92	47,625	62,012			
1957	20,023.94	15,240	20,024			
1958	34,124.43	25,725	34,124			
1959	96,612.10	72,117	96,612			
1960	51,233.09	37,857	51,233			
1961	45,576.23	33,327	45,576			
1962	160,704.65	116,226	160,705			
1963	35,277.32	25,220	35,277			
1964	132,026.61	93,293	132,027			
1965	101,220.30	70,652	101,220			
1966	312,430.32	215,336	312,430			
1967	131,207.60	89,262	131,208			
1968	64,377.10	43,212	64,377			
1969	73,912.94	48,930	73,913			
1970	125,323.34	81,768	125,323			
1971	23,860.50	15,340	23,860			
1972	44,905.67	28,429	44,906			
1973	30,181.87	18,806	30,182			
1974	108,910.28	66,771	108,910			

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 390.20 STRUCTURES AND IMPROVEMENTS - CLEARING

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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-R2.5						
1975	1,140.53	687	1,141			
1976	13,662.85	8,095	13,663			
1977	49,450.09	28,773	49,450			
1978	140,635.77	80,335	140,636			
1979	168,838.22	94,602	168,838			
1980	73,351.20	40,298	73,351			
1981	239,047.08	128,681	239,047			
1982	313,496.57	165,285	313,497			
1983	1,144,732.58	590,510	1,144,733			
1984	332,077.29	167,520	326,432	5,645	32.21	175
1985	221,460.34	109,162	212,715	8,745	32.96	265
1986	446,265.02	214,756	418,477	27,788	33.72	824
1987	200,518.94	94,120	183,404	17,115	34.49	496
1988	791,387.52	362,091	705,576	85,812	35.26	2,434
1989	477,191.71	212,608	414,291	62,901	36.04	1,745
1990	945,532.99	409,775	798,494	147,039	36.83	3,992
1991	1,085,917.94	457,258	891,020	194,898	37.63	5,179
1992	185,518.99	75,835	147,773	37,746	38.43	982
1993	281,674.70	111,673	217,608	64,067	39.23	1,633
1994	346,473.28	132,994	259,154	87,319	40.05	2,180
1995	342,400.54	127,109	247,687	94,714	40.87	2,317
1996	61,856.65	22,173	43,207	18,650	41.70	447
1997	410,399.59	141,871	276,452	133,948	42.53	3,149
1998	357,921.59	119,106	232,092	125,830	43.37	2,901
1999	157,625.31	50,391	98,193	59,432	44.22	1,344
2000	309,113.34	94,780	184,689	124,424	45.07	2,761
2001	7,831.32	2,298	4,478	3,353	45.93	73
2002	133,092.91	37,286	72,656	60,437	46.79	1,292
2003	67,243.80	17,939	34,956	32,288	47.66	677
2006	48,593.31	10,989	21,413	27,180	50.30	540
2007	49,323.84	10,487	20,435	28,889	51.18	564
2008	621,097.11	123,455	240,567	380,530	52.08	7,307
2009	55,652.46	10,291	20,053	35,599	52.98	672
2010	72,662.16	12,431	24,223	48,439	53.88	899
2011	77,484.51	12,183	23,740	53,745	54.78	981
2019	30.69	1	2	29	62.17	
2020	103.78	3	6	98	63.11	2
2021	16.13			16	64.06	
2022	48.57			49	64.76	1
	12,019,543.31	5,535,147	10,052,821	1,966,722		45,832

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 42.9 0.38

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 391.10 OFFICE FURNITURE AND EQUIPMENT - OFFICE FURNITURE

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 25-SQUARE						
1996	508,569.29	508,569	508,569			
1997	396,263.86	396,264	396,264			
1998	3,825,110.99	3,672,107	3,640,086	185,025	1.00	185,025
1999	370,595.47	340,948	337,975	32,620	2.00	16,310
2000	625,356.81	550,314	545,515	79,842	3.00	26,614
2001	257,780.61	216,536	214,648	43,133	4.00	10,783
2002	2,321.64	1,857	1,841	481	5.00	96
2003	1,991.66	1,514	1,501	491	6.00	82
2004	50,144.28	36,104	35,789	14,355	7.00	2,051
2007	113,595.52	68,157	67,563	46,033	10.00	4,603
2008	109,223.24	61,165	60,632	48,591	11.00	4,417
2009	256,957.00	133,618	132,453	124,504	12.00	10,375
2011	4,469.63	1,967	1,950	2,520	14.00	180
2013	19,217.56	6,918	6,858	12,360	16.00	772
2014	2,156.16	690	684	1,472	17.00	87
2015	1,515.37	424	420	1,095	18.00	61
2016	3,982.52	956	948	3,035	19.00	160
2017	3,105,707.71	621,142	615,724	2,489,984	20.00	124,499
2018	1,532.11	245	243	1,289	21.00	61
2019	107,369.97	12,884	12,771	94,599	22.00	4,300
2020	67,073.01	5,366	5,319	61,754	23.00	2,685
2021	26,352.96	1,054	1,045	25,308	24.00	1,054
2022	4,199.90	42	42	4,158	24.75	168
	9,861,487.27	6,638,841	6,588,840	3,272,647		394,383

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.3 4.00

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 391.15 OFFICE FURNITURE AND EQUIPMENT - OFFICE EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FULLY ACCRUED						
1998	2,471,673.48	2,471,673	2,471,673			
	2,471,673.48	2,471,673	2,471,673			
COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT ..					0.0	0.00

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 391.20 OFFICE FURNITURE AND EQUIPMENT - PERSONAL COMPUTERS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FULLY ACCRUED						
2011	7,121.44	7,121	7,121			
2014	226.56	227	227			
2015	78.41	78	78			
2016	695,514.40	695,514	695,515			
	702,940.81	702,940	702,941			
AMORTIZED SURVIVOR CURVE.. 5-SQUARE						
2017	2,325,430.32	2,325,430	2,325,430			
2018	1,031,552.71	825,242	655,291	376,262	1.00	376,262
2019	3,394,103.08	2,036,462	1,617,071	1,777,032	2.00	888,516
2020	2,532,993.77	1,013,198	804,539	1,728,455	3.00	576,152
2021	766,069.67	153,214	121,661	644,409	4.00	161,102
2022	3,928,114.54	196,406	155,958	3,772,157	4.75	794,138
	13,978,264.09	6,549,952	5,679,950	8,298,314		2,796,170
	14,681,204.90	7,252,892	6,382,891	8,298,314		2,796,170

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 3.0 19.05

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 391.25 OFFICE FURNITURE AND EQUIPMENT - INFORMATION SYSTEMS

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FULLY ACCRUED						
2012	16,670.54	16,671	16,671			
	16,670.54	16,671	16,671			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 392.00 TRANSPORTATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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 12-S1						
1963	2,377.02	2,377	2,377			
1964	849.77	850	850			
1967	2,385.54	2,386	2,386			
1968	7,060.90	7,061	7,061			
1969	24,428.68	24,429	24,429			
1971	2,706.20	2,706	2,706			
1976	33,734.44	33,734	33,734			
1977	8,171.15	8,171	8,171			
1978	4,268.65	4,269	4,269			
1979	24,463.00	24,463	24,463			
1980	3,440.39	3,440	3,440			
1982	1,986.98	1,987	1,987			
1983	1,579.89	1,580	1,580			
1985	76,592.93	76,593	76,593			
1987	182,432.72	182,433	182,433			
1988	124,176.21	124,176	124,176			
1990	28,449.91	28,450	28,450			
1991	241,840.06	241,840	241,840			
1992	48,057.45	48,057	48,057			
1993	106,992.60	106,993	106,993			
1994	160,884.12	160,884	160,884			
1995	35,977.15	35,977	35,977			
1997	106,958.36	106,958	106,958			
1998	688,952.78	688,953	688,953			
1999	269,945.15	263,871	101,250	168,695	0.27	168,695
2001	22,422.27	20,890	8,016	14,406	0.82	14,406
2007	14,289.29	11,074	4,249	10,040	2.70	3,719
2009	500,182.15	356,380	136,746	363,436	3.45	105,344
2010	4,478.69	3,042	1,167	3,312	3.85	860
2011	8,568.23	5,512	2,115	6,453	4.28	1,508
2013	539,913.39	304,603	116,879	423,034	5.23	80,886
2015	23,537.52	11,102	4,260	19,278	6.34	3,041
2016	1,897.86	797	306	1,592	6.96	229
2017	391,800.37	142,353	54,622	337,178	7.64	44,133
2019	3,850,654.55	901,708	345,993	3,504,662	9.19	381,356
2020	1,616,555.65	259,991	99,761	1,516,795	10.07	150,625
2021	7,500,902.02	618,824	237,448	7,263,454	11.01	659,714
	16,663,914.04	4,818,914	3,031,579	13,632,335		1,614,516

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 8.4 9.69

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 393.00 STORES EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 30-SQUARE						
1991	116,907.28	116,907	116,907			
1992	33,065.70	33,066	33,066			
1993	92,583.94	89,498	87,648	4,936	1.00	4,936
1994	8,880.98	8,289	8,118	763	2.00	382
1995	108,217.49	97,396	95,382	12,835	3.00	4,278
1996	56,895.63	49,310	48,291	8,605	4.00	2,151
1997	174,253.74	145,211	142,209	32,045	5.00	6,409
1998	260,084.86	208,068	203,766	56,319	6.00	9,386
1999	298,395.22	228,771	224,041	74,354	7.00	10,622
2000	17,529.46	12,855	12,589	4,940	8.00	618
2001	58,616.37	41,031	40,183	18,433	9.00	2,048
	1,225,430.67	1,030,402	1,012,200	213,231		40,830

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 5.2 3.33

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 394.00 TOOLS, SHOP AND GARAGE EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
SURVIVOR CURVE.. 25-SQUARE						
1996	361,727.46	361,727	361,727			
1997	469,696.75	469,697	469,697			
1998	2,189,450.05	2,101,872	2,079,519	109,931	1.00	109,931
1999	367,535.15	338,132	334,536	32,999	2.00	16,500
2000	730,864.56	643,161	636,321	94,544	3.00	31,515
2001	870,305.52	731,057	723,283	147,023	4.00	36,756
2002	548,497.57	438,798	434,132	114,366	5.00	22,873
2003	165,988.80	126,151	124,809	41,180	6.00	6,863
2004	36,461.22	26,252	25,973	10,488	7.00	1,498
2005	161,013.49	109,489	108,325	52,688	8.00	6,586
2007	3,432,741.36	2,059,645	2,037,741	1,395,000	10.00	139,500
2008	543,910.91	304,590	301,351	242,560	11.00	22,051
2009	162,939.66	84,729	83,828	79,112	12.00	6,593
2010	249,101.40	119,569	118,297	130,804	13.00	10,062
2012	153,962.94	61,585	60,930	93,033	15.00	6,202
2013	1,257,551.88	452,719	447,905	809,647	16.00	50,603
2014	5,399,728.82	1,727,913	1,709,537	3,690,192	17.00	217,070
2016	40.18	10	10	30	19.00	2
2017	50,830.97	10,166	10,058	40,773	20.00	2,039
2018	1,861,201.42	297,792	294,625	1,566,576	21.00	74,599
2019	1,024,060.92	122,887	121,580	902,481	22.00	41,022
2020	2,094,332.92	167,547	165,765	1,928,568	23.00	83,851
2021	915,119.35	36,605	36,216	878,903	24.00	36,621
2022	658,965.00	6,590	6,520	652,445	24.75	26,361
	23,706,028.30	10,798,683	10,692,685	13,013,343		949,098

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 13.7 4.00

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 395.00 LABORATORY EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FULLY ACCRUED						
2001	20,642.12	20,642	20,642			
2003	137,207.92	137,208	137,208			
2007	92,987.09	92,987	92,987			
2008	192,341.39	192,341	192,342			
	443,178.52	443,178	443,179			

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 0.0 0.00

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 396.00 POWER OPERATED EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

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 21-S1						
1957	488.92	489	489			
1965	24,505.09	24,505	24,505			
1969	44,354.37	44,354	44,354			
1972	2,161.01	2,161	2,161			
1976	33,267.85	33,268	33,268			
1985	20,423.43	19,101	20,423			
1987	3,758.69	3,413	3,759			
1991	341,909.57	290,787	327,211	14,699	3.14	4,681
1992	70,467.73	58,857	66,230	4,238	3.46	1,225
1993	115,489.96	94,646	106,502	8,988	3.79	2,372
1994	105,947.45	85,162	95,830	10,117	4.12	2,456
1995	142,529.95	112,259	126,321	16,209	4.46	3,634
1998	693,926.04	510,528	574,477	119,449	5.55	21,522
2000	1,291,875.66	902,466	1,015,510	276,366	6.33	43,660
2001	104,789.22	71,157	80,070	24,719	6.74	3,668
2008	17,679.13	9,185	10,336	7,343	10.09	728
2009	102,461.47	50,499	56,824	45,637	10.65	4,285
2012	59,074.85	23,883	26,875	32,200	12.51	2,574
2013	27,746.97	10,319	11,612	16,135	13.19	1,223
2015	420,487.79	126,748	142,624	277,864	14.67	18,941
2019	313.68	44	49	265	18.08	15
2021	175.39	8	9	166	20.00	8
2022	497.24	6	7	490	20.75	24
	3,624,331.46	2,473,845	2,769,446	854,885		111,016

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 7.7 3.06

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 397.00 COMMUNICATION EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FULLY ACCRUED						
2001	127,353.64	127,354	127,354			
	127,353.64	127,354	127,354			
AMORTIZED						
SURVIVOR CURVE.. 20-SQUARE						
2002	299,607.01	299,607	299,607			
2003	315,718.00	299,932	294,938	20,780	1.00	20,780
2004	12,044.18	10,840	10,660	1,385	2.00	692
2006	10,736.34	8,589	8,446	2,290	4.00	572
2007	46,358.24	34,769	34,190	12,168	5.00	2,434
2008	742,213.92	519,550	510,899	231,315	6.00	38,552
2009	53,147.78	34,546	33,971	19,177	7.00	2,740
2010	568,569.23	341,142	335,462	233,108	8.00	29,138
2011	123,860.32	68,123	66,989	56,872	9.00	6,319
2012	90,630.50	45,315	44,560	46,070	10.00	4,607
2013	206,511.62	92,930	91,383	115,129	11.00	10,466
2014	843,457.88	337,383	331,765	511,693	12.00	42,641
2015	56,030.07	19,611	19,284	36,746	13.00	2,827
2016	1,790,876.49	537,263	528,317	1,262,560	14.00	90,183
2017	10,086,082.62	2,521,521	2,479,535	7,606,548	15.00	507,103
2018	13,839,648.88	2,767,930	2,721,841	11,117,808	16.00	694,863
2019	7,779,542.28	1,166,931	1,147,500	6,632,042	17.00	390,120
2020	19,684,586.56	1,968,459	1,935,682	17,748,905	18.00	986,050
2021	6,525,121.00	326,256	320,823	6,204,298	19.00	326,542
2022	750,462.47	9,381	9,225	741,238	19.75	37,531
	63,825,205.39	11,410,078	11,225,075	52,600,130		3,194,160
	63,952,559.03	11,537,432	11,352,429	52,600,130		3,194,160

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 16.5 4.99

JERSEY CENTRAL POWER & LIGHT

ACCOUNT 398.00 MISCELLANEOUS EQUIPMENT

CALCULATED REMAINING LIFE DEPRECIATION ACCRUAL
RELATED TO ORIGINAL COST AS OF JUNE 30, 2022

YEAR (1)	ORIGINAL COST (2)	CALCULATED ACCRUED (3)	ALLOC. BOOK RESERVE (4)	FUTURE BOOK ACCRUALS (5)	REM. LIFE (6)	ANNUAL ACCRUAL (7)
FULLY ACCRUED						
2001	7,862.55	7,863	7,863			
	7,862.55	7,863	7,863			
AMORTIZED						
SURVIVOR CURVE.. 20-SQUARE						
2003	2,358.21	2,240	2,240	118	1.00	118
2006	3,815.65	3,053	3,053	763	4.00	191
2009	11,668.82	7,585	7,585	4,084	7.00	583
2010	16,291.04	9,775	9,775	6,516	8.00	814
2011	48,933.02	26,913	26,913	22,020	9.00	2,447
2019	90,345.33	13,552	13,552	76,793	17.00	4,517
2020	293.94	29	29	265	18.00	15
2021	45.62	2	2	44	19.00	2
2022	137.51	2	2	136	19.75	7
	173,889.14	63,151	63,151	110,738		8,694
	181,751.69	71,014	71,014	110,738		8,694

COMPOSITE REMAINING LIFE AND ANNUAL ACCRUAL RATE, PERCENT .. 12.7 4.78

JERSEY CENTRAL POWER AND LIGHT

COMPARISON OF CALCULATED ANNUAL ACCRUAL RATES AND ANNUAL ACCRUALS
RELATED TO ELECTRIC DISTRIBUTION PLANT AS OF JUNE 30, 2022

	ACCOUNT	ORIGINAL COST AS OF JUNE 30, 2022	EXISTING ACCRUAL AMOUNT	EXISTING ACCRUAL RATE	PROPOSED ACCRUAL AMOUNT		PROPOSED ACCRUAL RATE		INCREASE/ (DECREASE)
	(1)	(2)	(3)=(2)*(4)	(4)	(5)		(6)		(7)=(5)-(3)
	ELECTRIC PLANT								
	MISCELLANEOUS INTANGIBLE PLANT								
303.00	MISCELLANEOUS INTANGIBLE PLANT								
	FULLY ACCRUED	72,135,854.62	0	-	0		-		0
	AMORTIZED	61,432,256.15	8,612,677	*	8,612,677		*		0
	TOTAL MISCELLANEOUS INTANGIBLE PLANT	133,568,110.77	8,612,677		8,612,677				0
	TOTAL MISCELLANEOUS INTANGIBLE PLANT	**133,568,110.77**	**8,612,677**		**8,612,677**				**0**
	DISTRIBUTION PLANT								
360.12	DISTRIBUTION SUBSTATION EASEMENTS	690,806.44	9,050	1.31	7,494		1.08		(1,556)
360.22	DISTRIBUTION LINE EASEMENTS	26,255,822.88	191,668	0.73	141,991		0.54		(49,677)
361.10	STRUCTURES AND IMPROVEMENTS	26,988,132.97	224,002	0.83	301,968		1.12		77,966
361.20	STRUCTURES AND IMPROVEMENTS - CLEARING	64,044,190.99	960,663	1.50	837,809		1.31		(122,854)
362.00	SUBSTATION EQUIPMENT	576,435,754.65	8,012,457	1.39	9,546,040		1.66		1,533,583
364.00	POLES, TOWERS AND FIXTURES	800,508,801.13	23,214,755	2.90	20,429,190		2.55		(2,785,565)
365.00	OVERHEAD CONDUCTORS AND DEVICES	1,022,785,987.63	27,819,779	2.72	42,275,088		4.13		14,455,309
365.10	OVERHEAD CONDUCTORS AND DEVICES - CLEARING	208,194,285.07	3,247,831	1.56	2,861,456		1.37		(386,375)
366.00	UNDERGROUND CONDUIT	123,040,108.15	1,587,217	1.29	1,216,226		0.99		(370,991)
367.00	UNDERGROUND CONDUCTORS AND DEVICES	666,580,954.34	12,598,380	1.89	13,576,487		2.04		978,107
368.00	LINE TRANSFORMERS	888,357,192.90	22,564,273	2.54	19,965,243		2.25		(2,599,030)
369.00	SERVICES	480,062,882.98	5,808,761	1.21	8,783,393		1.83		2,974,632
370.00	METERS	191,634,445.65	14,315,093	7.47	10,918,308		5.70		(3,396,785)
370.10	SMART METERS	7,719,088.01	576,616	7.47	384,038		4.98		(192,578)
371.00	INSTALLATIONS ON CUSTOMER PREMISES	27,065,403.65	1,131,334	4.18	1,303,382		4.82		172,048
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	252,602,837.12	8,411,674	3.33	8,459,895		3.35		48,221
373.30	STREET LIGHTING AND SIGNAL SYSTEMS - LED	2,212,833.06	64,615	2.92	76,521		3.46		11,906
	TOTAL DISTRIBUTION PLANT	**5,365,179,527.62**	**130,738,168**	**2.44**	**141,084,529**		**2.63**		**10,346,361**
	GENERAL PLANT								
389.20	LAND RIGHTS	12,724.68	508	3.99	471		3.70		(37)
390.10	STRUCTURES AND IMPROVEMENTS	86,872,045.16	1,329,142	1.53	1,342,112		1.54		12,970
390.20	STRUCTURES AND IMPROVEMENTS - CLEARING	12,019,543.31	54,088	0.45	45,832		0.38		(8,256)
391.10	OFFICE FURNITURE	9,861,487.27	394,526	4.00	394,383		4.00		(143)
391.15	OFFICE EQUIPMENT	2,471,673.48	0	-	0	**	-		0
391.20	PERSONAL COMPUTERS								
	FULLY ACCRUED	702,940.81	0	-	0		-		0
	AMORTIZED	13,978,264.09	2,796,170	20.00	2,796,170		20.00		0
	TOTAL PERSONAL COMPUTERS	14,681,204.90	2,796,170	19.05	2,796,170		19.05		0
391.25	INFORMATION SYSTEMS	16,670.54	0	-	0	***	-		0
	TOTAL ACCOUNT 391	27,031,036.19	3,190,696	11.80	3,190,553		11.80		
392.00	TRANSPORTATION EQUIPMENT	16,663,914.04	734,879	4.41	1,614,223		9.69		879,344
393.00	STORES EQUIPMENT	1,225,430.67	40,807	3.33	40,830		3.33		23
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	23,706,028.30	948,241	4.00	949,098		4.00		857
395.00	LABORATORY EQUIPMENT	443,178.52	22,159	5.00	0	****	-		(22,159)
396.00	POWER OPERATED EQUIPMENT	3,624,331.46	116,341	3.21	106,746		2.95		(9,595)
397.00	COMMUNICATION EQUIPMENT								
	FULLY ACCRUED	127,353.64	0	-	0		-		0
	AMORTIZED	63,825,205.39	3,192,456	5.00	3,194,160		5.00		1,704
	TOTAL COMMUNICATION EQUIPMENT	63,952,559.03	3,192,456	4.99	3,194,160		4.99		1,704
398.00	MISCELLANEOUS EQUIPMENT								
	FULLY ACCRUED	7,862.55	0	-	0		-		0
	AMORTIZED	173,889.14	8,694	5.00	8,694		5.00		0
	TOTAL MISCELLANEOUS EQUIPMENT	181,751.69	8,694	4.78	8,694		4.78		0
	TOTAL GENERAL PLANT	**235,732,543.05**	**9,638,011**	**4.09**	**10,492,719**		**4.45**		**854,708**

JERSEY CENTRAL POWER AND LIGHT

COMPARISON OF CALCULATED ANNUAL ACCRUAL RATES AND ANNUAL ACCRUALS
RELATED TO ELECTRIC DISTRIBUTION PLANT AS OF JUNE 30, 2022

	ACCOUNT	ORIGINAL COST AS OF JUNE 30, 2022	EXISTING ACCRUAL AMOUNT	EXISTING ACCRUAL RATE	PROPOSED ACCRUAL AMOUNT	PROPOSED ACCRUAL RATE	INCREASE/ (DECREASE)
	(1)	(2)	(3)=(2)*(4)	(4)	(5)	(6)	(7)=(5)-(3)
	UNRECOVERED RESERVE ADJUSTMENT FOR AMORTIZATION						
391.10	OFFICE FURNITURE		148,234		(130,219) *****		(278,453)
391.15	OFFICE EQUIPMENT		113,765		48,632 *****		(65,133)
391.20	PERSONAL COMPUTERS		1,952,859		2,284,126 *****		331,267
391.25	INFORMATION SYSTEMS		209		205 *****		(4)
393.00	STORES EQUIPMENT		(13,941)		(14,645) *****		(704)
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT		137,204		56,403 *****		(80,801)
397.00	COMMUNICATION EQUIPMENT		359,526		257,130 *****		(102,396)
398.00	MISCELLANEOUS EQUIPMENT		(20,407)		(28,076) *****		(7,669)
	TOTAL UNRECOVERED RESERVE ADJUSTMENT FOR AMORTIZATION		**2,677,449**		**2,473,556**		**(203,893)**
	TOTAL DEPRECIABLE ELECTRIC PLANT	**5,734,480,181.44**	**151,666,305**	**2.64**	**162,663,481**	**2.84**	**10,997,176**
	NONDEPRECIABLE PLANT						
301.00	ORGNAIZATION	56,399.61					
302.00	FRANCHISES AND CONSENTS	2,995.02					
360.11	LAND	5,699,009.30					
360.21	LAND	11,988.31					
374.00	ARC DISTRIBUTION PLANT	45,656.70					
389.10	LAND	1,467,829.14					
390.30	STRUCTURES AND IMPROVEMENTS - LEASEHOLDS	2,879,848.29					
397.10	COMMUNCATOIN EQUIPMENT - FIBER OPTIC	0.00					
399.10	ARC GENERAL PLANT	1,444,666.47					
	TOTAL NONDEPRECIABLE PLANT	**11,608,392.84**					
	TOTAL ELECTRIC PLANT	**5,746,088,574.28**					

* Assets are amortized individually using a 14.29% annual accrual rate consistent with a 7-year amortization period.
** Assets as of July 1, 2022 will utilize a 5.00% annual accrual rate consistent with the amortization period.
*** Assets as of July 1, 2022 will utilize a 20.00% annual accrual rate consistent with the amortization period.
**** Assets as of July 1, 2022 will utilize a 5.00% annual accrual rate consistent with the amortization period.
***** 4-Year amortization of unrecovered reserve related to amortization accounting.

NOTE: Assets added to Account 303.10 (Miscellaneous Intangible Plant - Cloud Assets) will be amortized over the life of the agreement.

Appendix A

JOHN SPANOS

DEPRECIATION EXPERIENCE

Q. Please state your name.

A. My name is John J. Spanos.

Q. What is your educational background?

A. I have Bachelor of Science degrees in Industrial Management and Mathematics from Carnegie-Mellon University and a Master of Business Administration from York College.

Q. Do you belong to any professional societies?

A. Yes. I am a member and past President of the Society of Depreciation Professionals and a member of the American Gas Association/Edison Electric Institute Industry Accounting Committee.

Q. Do you hold any special certification as a depreciation expert?

A. Yes. The Society of Depreciation Professionals has established national standards for depreciation professionals. The Society administers an examination to become certified in this field. I passed the certification exam in September 1997 and was recertified in August 2003, February 2008, January 2013, February 2018 and February 2023.

Q. Please outline your experience in the field of depreciation.

A. In June 1986, I was employed by Gannett Fleming Valuation and Rate Consultants, Inc. as a Depreciation Analyst. During the period from June 1986 through December 1995, I helped prepare numerous depreciation and original cost studies for utility companies in various industries. I helped perform depreciation studies for the following telephone companies: United Telephone of Pennsylvania, United Telephone of New Jersey, and Anchorage Telephone Utility. I helped perform depreciation studies for the following companies in

the railroad industry: Union Pacific Railroad, Burlington Northern Railroad, and Wisconsin Central Transportation Corporation.

I helped perform depreciation studies for the following organizations in the electric utility industry: Chugach Electric Association, The Cincinnati Gas and Electric Company (CG&E), The Union Light, Heat and Power Company (ULH&P), Northwest Territories Power Corporation, and the City of Calgary - Electric System.

I helped perform depreciation studies for the following pipeline companies: TransCanada Pipelines Limited, Trans Mountain Pipe Line Company Ltd., Interprovincial Pipe Line Inc., Nova Gas Transmission Limited and Lakehead Pipeline Company.

I helped perform depreciation studies for the following gas utility companies: Columbia Gas of Pennsylvania, Columbia Gas of Maryland, The Peoples Natural Gas Company, T. W. Phillips Gas & Oil Company, CG&E, ULH&P, Lawrenceburg Gas Company and Penn Fuel Gas, Inc.

I helped perform depreciation studies for the following water utility companies: Indiana-American Water Company, Consumers Pennsylvania Water Company and The York Water Company; and depreciation and original cost studies for Philadelphia Suburban Water Company and Pennsylvania-American Water Company.

In each of the above studies, I assembled and analyzed historical and simulated data, performed field reviews, developed preliminary estimates of service life and net salvage, calculated annual depreciation, and prepared reports for submission to state public utility commissions or federal regulatory agencies. I performed these studies under the general direction of William M. Stout, P.E.

In January 1996, I was assigned to the position of Supervisor of Depreciation Studies. In July 1999, I was promoted to the position of Manager, Depreciation and

Valuation Studies. In December 2000, I was promoted to the position as Vice-President of Gannett Fleming Valuation and Rate Consultants, Inc., in April 2012, I was promoted to the position as Senior Vice President of the Valuation and Rate Division of Gannett Fleming Inc. (now doing business as Gannett Fleming Valuation and Rate Consultants, LLC) and in January of 2019, I was promoted to my present position of President of Gannett Fleming Valuation and Rate Consultants, LLC. In my current position I am responsible for conducting all depreciation, valuation and original cost studies, including the preparation of final exhibits and responses to data requests for submission to the appropriate regulatory bodies.

Since January 1996, I have conducted depreciation studies similar to those previously listed including assignments for Pennsylvania-American Water Company; Aqua Pennsylvania; Kentucky-American Water Company; Virginia-American Water Company; Indiana-American Water Company; Iowa-American Water Company; New Jersey-American Water Company; Hampton Water Works Company; Omaha Public Power District; Enbridge Pipe Line Company; Inc.; Columbia Gas of Virginia, Inc.; Virginia Natural Gas Company National Fuel Gas Distribution Corporation - New York and Pennsylvania Divisions; The City of Bethlehem - Bureau of Water; The City of Coatesville Authority; The City of Lancaster - Bureau of Water; Peoples Energy Corporation; The York Water Company; Public Service Company of Colorado; Enbridge Pipelines; Enbridge Gas Distribution, Inc.; Reliant Energy-HLP; Massachusetts-American Water Company; St. Louis County Water Company; Missouri-American Water Company; Chugach Electric Association; Alliant Energy; Oklahoma Gas & Electric Company; Nevada Power Company; Dominion Virginia Power; NUI-Virginia Gas Companies; Pacific Gas & Electric Company; PSI Energy; NUI - Elizabethtown Gas Company; Cinergy Corporation – CG&E; Cinergy

Corporation – ULH&P; Columbia Gas of Kentucky; South Carolina Electric & Gas Company; Idaho Power Company; El Paso Electric Company; Aqua North Carolina; Aqua Ohio; Aqua Texas, Inc.; Aqua Illinois, Inc.; Ameren Missouri; Central Hudson Gas & Electric; Centennial Pipeline Company; CenterPoint Energy-Arkansas; CenterPoint Energy – Oklahoma; CenterPoint Energy – Entex; CenterPoint Energy - Louisiana; NSTAR – Boston Edison Company; Westar Energy, Inc.; United Water Pennsylvania; PPL Electric Utilities; PPL Gas Utilities; Wisconsin Power & Light Company; TransAlaska Pipeline; Avista Corporation; Northwest Natural Gas; Allegheny Energy Supply, Inc.; Public Service Company of North Carolina; South Jersey Gas Company; Duquesne Light Company; MidAmerican Energy Company; Laclede Gas; Duke Energy Company; E.ON U.S. Services Inc.; Elkton Gas Services; Anchorage Water and Wastewater Utility; Kansas City Power and Light; Duke Energy North Carolina; Duke Energy South Carolina; Monongahela Power Company; Potomac Edison Company; Duke Energy Ohio Gas; Duke Energy Kentucky; Duke Energy Indiana; Duke Energy Progress; Northern Indiana Public Service Company; Tennessee- American Water Company; Columbia Gas of Maryland; Maryland-American Water Company; Bonneville Power Administration; NSTAR Electric and Gas Company; EPCOR Distribution, Inc.; B. C. Gas Utility, Ltd; Entergy Arkansas; Entergy Texas; Entergy Mississippi; Entergy Louisiana; Entergy Gulf States Louisiana; the Borough of Hanover; Louisville Gas and Electric Company; Kentucky Utilities Company; Madison Gas and Electric; Central Maine Power; PEPCO; PacifiCorp; Minnesota Energy Resource Group; Jersey Central Power & Light Company; Cheyenne Light, Fuel and Power Company; United Water Arkansas; Central Vermont Public Service Corporation; Green Mountain Power; Portland General Electric Company; Atlantic City Electric; Nicor Gas Company; Black Hills Power; Black Hills Colorado Gas; Black Hills Energy Arkansas, Inc.; Black Hills Kansas

Gas; Black Hills Service Company; Black Hills Utility Holdings; Public Service Company of Oklahoma; City of Dubois; Peoples Gas Light and Coke Company; North Shore Gas Company; Connecticut Light and Power; New York State Electric and Gas Corporation; Rochester Gas and Electric Corporation; Greater Missouri Operations; Tennessee Valley Authority; Omaha Public Power District; Indianapolis Power & Light Company; Vermont Gas Systems, Inc.; Metropolitan Edison; Pennsylvania Electric; West Penn Power; Pennsylvania Power; PHI Service Company - Delmarva Power and Light; Atmos Energy Corporation; Citizens Energy Group; PSE&G Company; Berkshire Gas Company; Alabama Gas Corporation; Mid-Atlantic Interstate Transmission, LLC; SUEZ Water; WEC Energy Group; Rocky Mountain Natural Gas, LLC; Illinois-American Water Company; Northern Illinois Gas Company; Public Service of New Hampshire and Newtown Artesian Water Company.

My additional duties include determining final life and salvage estimates, conducting field reviews, presenting recommended depreciation rates to management for its consideration and supporting such rates before regulatory bodies.

Q. Have you submitted testimony to any state utility commission on the subject of utility plant depreciation?

A. Yes. I have submitted testimony to the Pennsylvania Public Utility Commission; the Commonwealth of Kentucky Public Service Commission; the Public Utilities Commission of Ohio; the Nevada Public Utility Commission; the Public Utilities Board of New Jersey; the Missouri Public Service Commission; the Massachusetts Department of Telecommunications and Energy; the Alberta Energy & Utility Board; the Idaho Public Utility Commission; the Louisiana Public Service Commission; the State Corporation Commission of Kansas; the Oklahoma Corporate Commission; the Public Service

Commission of South Carolina; Railroad Commission of Texas – Gas Services Division; the New York Public Service Commission; Illinois Commerce Commission; the Indiana Utility Regulatory Commission; the California Public Utilities Commission; the Federal Energy Regulatory Commission ("FERC"); the Arkansas Public Service Commission; the Public Utility Commission of Texas; Maryland Public Service Commission; Washington Utilities and Transportation Commission; The Tennessee Regulatory Commission; the Regulatory Commission of Alaska; Minnesota Public Utility Commission; Utah Public Service Commission; District of Columbia Public Service Commission; the Mississippi Public Service Commission; Delaware Public Service Commission; Virginia State Corporation Commission; Colorado Public Utility Commission; Oregon Public Utility Commission; South Dakota Public Utilities Commission; Wisconsin Public Service Commission; Wyoming Public Service Commission; the Public Service Commission of West Virginia; Maine Public Utility Commission; Iowa Utility Board; Connecticut Public Utilities Regulatory Authority; New Mexico Public Regulation Commission; Commonwealth of Massachusetts Department of Public Utilities; Rhode Island Public Utilities Commission and the North Carolina Utilities Commission.

Q. Have you had any additional education relating to utility plant depreciation?

A. Yes. I have completed the following courses conducted by Depreciation Programs, Inc.: "Techniques of Life Analysis," "Techniques of Salvage and Depreciation Analysis," "Forecasting Life and Salvage," "Modeling and Life Analysis Using Simulation," and "Managing a Depreciation Study." I have also completed the "Introduction to Public Utility Accounting" program conducted by the American Gas Association.

Q. Does this conclude your qualification statement?

A. Yes.

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY

	Year	Jurisdiction	Docket No.	Client Utility	Subject
01.	1998	PA PUC	R-00984375	City of Bethlehem – Bureau of Water	Original Cost and Depreciation
02.	1998	PA PUC	R-00984567	City of Lancaster	Original Cost and Depreciation
03.	1999	PA PUC	R-00994605	The York Water Company	Depreciation
04.	2000	D.T.&E.	DTE 00-105	Massachusetts-American Water Company	Depreciation
05.	2001	PA PUC	R-00016114	City of Lancaster	Original Cost and Depreciation
06.	2001	PA PUC	R-00017236	The York Water Company	Depreciation
07.	2001	PA PUC	R-00016339	Pennsylvania-American Water Company	Depreciation
08.	2001	OH PUC	01-1228-GA-AIR	Cinergy Corp – Cincinnati Gas & Elect Company	Depreciation
09.	2001	KY PSC	2001-092	Cinergy Corp – Union Light, Heat & Power Co.	Depreciation
10.	2002	PA PUC	R-00016750	Philadelphia Suburban Water Company	Depreciation
11.	2002	KY PSC	2002-00145	Columbia Gas of Kentucky	Depreciation
12.	2002	NJ BPU	GF02040245	NUI Corporation/Elizabethtown Gas Company	Depreciation
13.	2002	ID PUC	IPC-E-03-7	Idaho Power Company	Depreciation
14.	2003	PA PUC	R-0027975	The York Water Company	Depreciation
15.	2003	IN URC	R-0027975	Cinergy Corp – PSI Energy, Inc.	Depreciation
16.	2003	PA PUC	R-00038304	Pennsylvania-American Water Company	Depreciation
17.	2003	MO PSC	WR-2003-0500	Missouri-American Water Company	Depreciation
18.	2003	FERC	ER03-1274-000	NSTAR-Boston Edison Company	Depreciation
19.	2003	NJ BPU	BPU 03080683	South Jersey Gas Company	Depreciation
20.	2003	NV PUC	03-10001	Nevada Power Company	Depreciation
21.	2003	LA PSC	U-27676	CenterPoint Energy – Arkla	Depreciation
22.	2003	PA PUC	R-00038805	Pennsylvania Suburban Water Company	Depreciation
23.	2004	AB En/Util Bd	1306821	EPCOR Distribution, Inc.	Depreciation
24.	2004	PA PUC	R-00038168	National Fuel Gas Distribution Corp (PA)	Depreciation
25.	2004	PA PUC	R-00049255	PPL Electric Utilities	Depreciation
26.	2004	PA PUC	R-00049165	The York Water Company	Depreciation
27.	2004	OK Corp Cm	PUC 200400187	CenterPoint Energy – Arkla	Depreciation
28.	2004	OH PUC	04-680-El-AIR	Cinergy Corp. – Cincinnati Gas and Electric Company	Depreciation
29.	2004	RR Com of TX	GUD#	CenterPoint Energy – Entex Gas Services Div.	Depreciation
30.	2004	NY PUC	04-G-1047	National Fuel Gas Distribution Gas (NY)	Depreciation
31.	2004	AR PSC	04-121-U	CenterPoint Energy – Arkla	Depreciation
32.	2005	IL CC	05-ICC-06	North Shore Gas Company	Depreciation

33.	2005	IL CC	05-ICC-06	Peoples Gas Light and Coke Company	Depreciation
34.	2005	KY PSC	2005-00042	Union Light Heat & Power	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
35.	2005	IL CC	05-0308	MidAmerican Energy Company	Depreciation
36.	2005	MO PSC	GF-2005	Laclede Gas Company	Depreciation
37.	2005	KS CC	05-WSEE-981-RTS	Westar Energy	Depreciation
38.	2005	RR Com of TX	GUD #	CenterPoint Energy – Entex Gas Services Div.	Depreciation
39.	2005	US District Court	Cause No. 1:99-CV-1693-LJM/VSS	Cinergy Corporation	Accounting
40.	2005	OK CC	PUD 200500151	Oklahoma Gas and Electric Company	Depreciation
41.	2005	MA Dept Tele-com & Ergy	DTE 05-85	NSTAR	Depreciation
42.	2005	NY PUC	05-E-934/05-G-0935	Central Hudson Gas & Electric Company	Depreciation
43.	2005	AK Reg Com	U-04-102	Chugach Electric Association	Depreciation
44.	2005	CA PUC	A05-12-002	Pacific Gas & Electric	Depreciation
45.	2006	PA PUC	R-00051030	Aqua Pennsylvania, Inc.	Depreciation
46.	2006	PA PUC	R-00051178	T.W. Phillips Gas and Oil Company	Depreciation
47.	2006	NC Util Cm.	G-5, Sub522	Pub. Service Company of North Carolina	Depreciation
48.	2006	PA PUC	R-00051167	City of Lancaster	Depreciation
49.	2006	PA PUC	R00061346	Duquesne Light Company	Depreciation
50.	2006	PA PUC	R-00061322	The York Water Company	Depreciation
51.	2006	PA PUC	R-00051298	PPL GAS Utilities	Depreciation
52.	2006	PUC of TX	32093	CenterPoint Energy – Houston Electric	Depreciation
53.	2006	KY PSC	2006-00172	Duke Energy Kentucky	Depreciation
54.	2006	SC PSC		SCANA	Accounting
55.	2006	AK Reg Com	U-06-6	Municipal Light and Power	Depreciation
56.	2006	DE PSC	06-284	Delmarva Power and Light	Depreciation
57.	2006	IN URC	IURC43081	Indiana American Water Company	Depreciation
58.	2006	AK Reg Com	U-06-134	Chugach Electric Association	Depreciation
59.	2006	MO PSC	WR-2007-0216	Missouri American Water Company	Depreciation
60.	2006	FERC	IS05-82-002, et al	TransAlaska Pipeline	Depreciation
61.	2006	PA PUC	R-00061493	National Fuel Gas Distribution Corp. (PA)	Depreciation
62.	2007	NC Util Com.	E-7 SUB 828	Duke Energy Carolinas, LLC	Depreciation
63.	2007	OH PSC	08-709-EL-AIR	Duke Energy Ohio Gas	Depreciation
64.	2007	PA PUC	R-00072155	PPL Electric Utilities Corporation	Depreciation
65.	2007	KY PSC	2007-00143	Kentucky American Water Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
66.	2007	PA PUC	R-00072229	Pennsylvania American Water Company	Depreciation
67.	2007	KY PSC	2007-0008	NiSource – Columbia Gas of Kentucky	Depreciation
68.	2007	NY PSC	07-G-0141	National Fuel Gas Distribution Corp (NY)	Depreciation
69.	2008	AK PSC	U-08-004	Anchorage Water & Wastewater Utility	Depreciation
70.	2008	TN Reg Auth	08-00039	Tennessee-American Water Company	Depreciation
71.	2008	DE PSC	08-96	Artesian Water Company	Depreciation
72.	2008	PA PUC	R-2008-2023067	The York Water Company	Depreciation
73.	2008	KS CC	08-WSEE1-RTS	Westar Energy	Depreciation
74.	2008	IN URC	43526	Northern Indiana Public Service Company	Depreciation
75.	2008	IN URC	43501	Duke Energy Indiana	Depreciation
76.	2008	MD PSC	9159	NiSource – Columbia Gas of Maryland	Depreciation
77.	2008	KY PSC	2008-000251	Kentucky Utilities	Depreciation
78.	2008	KY PSC	2008-000252	Louisville Gas & Electric	Depreciation
79.	2008	PA PUC	2008-20322689	Pennsylvania American Water Co. - Wastewater	Depreciation
80.	2008	NY PSC	08-E887/08-00888	Central Hudson	Depreciation
81.	2008	WV TC	VE-080416/VG-8080417	Avista Corporation	Depreciation
82.	2008	IL CC	ICC-09-166	Peoples Gas, Light and Coke Company	Depreciation
83.	2009	IL CC	ICC-09-167	North Shore Gas Company	Depreciation
84.	2009	DC PSC	1076	Potomac Electric Power Company	Depreciation
85.	2009	KY PSC	2009-00141	NiSource – Columbia Gas of Kentucky	Depreciation
86.	2009	FERC	ER08-1056-002	Entergy Services	Depreciation
87.	2009	PA PUC	R-2009-2097323	Pennsylvania American Water Company	Depreciation
88.	2009	NC Util Cm	E-7, Sub 090	Duke Energy Carolinas, LLC	Depreciation
89.	2009	KY PSC	2009-00202	Duke Energy Kentucky	Depreciation
90.	2009	VA St. CC	PUE-2009-00059	Aqua Virginia, Inc.	Depreciation
91.	2009	PA PUC	2009-2132019	Aqua Pennsylvania, Inc.	Depreciation
92.	2009	MS PSC	Docket No. 2011-UA-183	Entergy Mississippi	Depreciation
93.	2009	AK PSC	09-08-U	Entergy Arkansas	Depreciation
94.	2009	TX PUC	37744	Entergy Texas	Depreciation
95.	2009	TX PUC	37690	El Paso Electric Company	Depreciation
96.	2009	PA PUC	R-2009-2106908	The Borough of Hanover	Depreciation
97.	2009	KS CC	10-KCPE-415-RTS	Kansas City Power & Light	Depreciation
98.	2009	PA PUC	R-2009-	United Water Pennsylvania	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
99.	2009	OH PUC		Aqua Ohio Water Company	Depreciation
100.	2009	WI PSC	3270-DU-103	Madison Gas & Electric Company	Depreciation
101.	2009	MO PSC	WR-2010	Missouri American Water Company	Depreciation
102.	2009	AK Reg Cm	U-09-097	Chugach Electric Association	Depreciation
103.	2010	IN URC	43969	Northern Indiana Public Service Company	Depreciation
104.	2010	WI PSC	6690-DU-104	Wisconsin Public Service Corp.	Depreciation
105.	2010	PA PUC	R-2010-2161694	PPL Electric Utilities Corp.	Depreciation
106.	2010	KY PSC	2010-00036	Kentucky American Water Company	Depreciation
107.	2010	PA PUC	R-2009-2149262	Columbia Gas of Pennsylvania	Depreciation
108.	2010	MO PSC	GR-2010-0171	Laclede Gas Company	Depreciation
109.	2010	SC PSC	2009-489-E	South Carolina Electric & Gas Company	Depreciation
110.	2010	NJ BD OF PU	ER09080664	Atlantic City Electric	Depreciation
111.	2010	VA St. CC	PUE-2010-00001	Virginia American Water Company	Depreciation
112.	2010	PA PUC	R-2010-2157140	The York Water Company	Depreciation
113.	2010	MO PSC	ER-2010-0356	Greater Missouri Operations Company	Depreciation
114.	2010	MO PSC	ER-2010-0355	Kansas City Power and Light	Depreciation
115.	2010	PA PUC	R-2010-2167797	T.W. Phillips Gas and Oil Company	Depreciation
116.	2010	PSC SC	2009-489-E	SCANA – Electric	Depreciation
117.	2010	PA PUC	R-2010-22010702	Peoples Natural Gas, LLC	Depreciation
118.	2010	AK PSC	10-067-U	Oklahoma Gas and Electric Company	Depreciation
119.	2010	IN URC	Cause No. 43894	Northern Indiana Public Serv. Company - NIFL	Depreciation
120.	2010	IN URC	Cause No. 43894	Northern Indiana Public Serv. Co. - Kokomo	Depreciation
121.	2010	PA PUC	R-2010-2166212	Pennsylvania American Water Co. - WW	Depreciation
122.	2010	NC Util Cn.	W-218,SUB310	Aqua North Carolina, Inc.	Depreciation
123.	2011	OH PUC	11-4161-WS-AIR	Ohio American Water Company	Depreciation
124.	2011	MS PSC	EC-123-0082-00	Entergy Mississippi	Depreciation
125.	2011	CO PUC	11AL-387E	Black Hills Colorado	Depreciation
126.	2011	PA PUC	R-2010-2215623	Columbia Gas of Pennsylvania	Depreciation
127.	2011	PA PUC	R-2010-2179103	City of Lancaster – Bureau of Water	Depreciation
128.	2011	IN URC	43114 IGCC 4S	Duke Energy Indiana	Depreciation
129.	2011	FERC	IS11-146-000	Enbridge Pipelines (Southern Lights)	Depreciation
130.	2011	IL CC	11-0217	MidAmerican Energy Corporation	Depreciation
131.	2011	OK CC	201100087	Oklahoma Gas & Electric Company	Depreciation
132.	2011	PA PUC	2011-2232243	Pennsylvania American Water Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
133.	2011	FERC	RP11-___-000	Carolina Gas Transmission	Depreciation
134.	2012	WA UTC	UE-120436/UG-120437	Avista Corporation	Depreciation
135.	2012	AK Reg Cm	U-12-009	Chugach Electric Association	Depreciation
136.	2012	MA PUC	DPU 12-25	Columbia Gas of Massachusetts	Depreciation
137.	2012	TX PUC	40094	El Paso Electric Company	Depreciation
138.	2012	ID PUC	IPC-E-12	Idaho Power Company	Depreciation
139.	2012	PA PUC	R-2012-2290597	PPL Electric Utilities	Depreciation
140.	2012	PA PUC	R-2012-2311725	Borough of Hanover – Bureau of Water	Depreciation
141.	2012	KY PSC	2012-00222	Louisville Gas and Electric Company	Depreciation
142.	2012	KY PSC	2012-00221	Kentucky Utilities Company	Depreciation
143.	2012	PA PUC	R-2012-2285985	Peoples Natural Gas Company	Depreciation
144.	2012	DC PSC	Case 1087	Potomac Electric Power Company	Depreciation
145.	2012	OH PSC	12-1682-EL-AIR	Duke Energy Ohio (Electric)	Depreciation
146.	2012	OH PSC	12-1685-GA-AIR	Duke Energy Ohio (Gas)	Depreciation
147.	2012	PA PUC	R-2012-2310366	City of Lancaster – Sewer Fund	Depreciation
148.	2012	PA PUC	R-2012-2321748	Columbia Gas of Pennsylvania	Depreciation
149.	2012	FERC	ER-12-2681-000	ITC Holdings	Depreciation
150.	2012	MO PSC	ER-2012-0174	Kansas City Power and Light	Depreciation
151.	2012	MO PSC	ER-2012-0175	KCPL Greater Missouri Operations Company	Depreciation
152.	2012	MO PSC	GO-2012-0363	Laclede Gas Company	Depreciation
153.	2012	MN PUC	G007,001/D-12-533	Integrys – MN Energy Resource Group	Depreciation
154.	2012	TX PUC	SOAH 582-14-1051/ TECQ 2013-2007-UCR	Aqua Texas	Depreciation
155.	2012	PA PUC	2012-2336379	York Water Company	Depreciation
156.	2013	NJ BPU	ER12121071	PHI Service Company– Atlantic City Electric	Depreciation
157.	2013	KY PSC	2013-00167	Columbia Gas of Kentucky	Depreciation
158.	2013	VA St CC	2013-00020	Virginia Electric and Power Company	Depreciation
159.	2013	IA Util Bd	2013-0004	MidAmerican Energy Corporation	Depreciation
160.	2013	PA PUC	2013-2355276	Pennsylvania American Water Company	Depreciation
161.	2013	NY PSC	13-E-0030, 13-G-0031, 13-S-0032	Consolidated Edison of New York	Depreciation
162.	2013	PA PUC	2013-2355886	Peoples TWP LLC	Depreciation
163.	2013	TN Reg Auth	12-0504	Tennessee American Water	Depreciation
164.	2013	ME PUC	2013-168	Central Maine Power Company	Depreciation
165.	2013	DC PSC	Case 1103	PHI Service Company – PEPCO	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
166.	2013	WY PSC	2003-ER-13	Cheyenne Light, Fuel and Power Company	Depreciation
167.	2013	FERC	ER13-2428-0000	Kentucky Utilities	Depreciation
168.	2013	FERC	ER13- -0000	MidAmerican Energy Company	Depreciation
169.	2013	FERC	ER13-2410-0000	PPL Utilities	Depreciation
170.	2013	PA PUC	R-2013-2372129	Duquesne Light Company	Depreciation
171.	2013	NJ BPU	ER12111052	Jersey Central Power and Light Company	Depreciation
172.	2013	PA PUC	R-2013-2390244	Bethlehem, City of – Bureau of Water	Depreciation
173.	2013	OK CC	UM 1679	Oklahoma, Public Service Company of	Depreciation
174.	2013	IL CC	13-0500	Nicor Gas Company	Depreciation
175.	2013	WY PSC	20000-427-EA-13	PacifiCorp	Depreciation
176.	2013	UT PSC	13-035-02	PacifiCorp	Depreciation
177.	2013	OR PUC	UM 1647	PacifiCorp	Depreciation
178.	2013	PA PUC	2013-2350509	Dubois, City of	Depreciation
179.	2014	IL CC	14-0224	North Shore Gas Company	Depreciation
180.	2014	FERC	ER14- -0000	Duquesne Light Company	Depreciation
181.	2014	SD PUC	EL14-026	Black Hills Power Company	Depreciation
182.	2014	WY PSC	20002-91-ER-14	Black Hills Power Company	Depreciation
183.	2014	PA PUC	2014-2428304	Borough of Hanover – Municipal Water Works	Depreciation
184.	2014	PA PUC	2014-2406274	Columbia Gas of Pennsylvania	Depreciation
185.	2014	IL CC	14-0225	Peoples Gas Light and Coke Company	Depreciation
186.	2014	MO PSC	ER-2014-0258	Ameren Missouri	Depreciation
187.	2014	KS CC	14-BHCG-502-RTS	Black Hills Service Company	Depreciation
188.	2014	KS CC	14-BHCG-502-RTS	Black Hills Utility Holdings	Depreciation
189.	2014	KS CC	14-BHCG-502-RTS	Black Hills Kansas Gas	Depreciation
190.	2014	PA PUC	2014-2418872	Lancaster, City of – Bureau of Water	Depreciation
191.	2014	WV PSC	14-0701-E-D	First Energy – MonPower/PotomacEdison	Depreciation
192	2014	VA St CC	PUC-2014-00045	Aqua Virginia	Depreciation
193.	2014	VA St CC	PUE-2013	Virginia American Water Company	Depreciation
194.	2014	OK CC	PUD201400229	Oklahoma Gas and Electric Company	Depreciation
195.	2014	OR PUC	UM1679	Portland General Electric	Depreciation
196.	2014	IN URC	Cause No. 44576	Indianapolis Power & Light	Depreciation
197.	2014	MA DPU	DPU. 14-150	NSTAR Gas	Depreciation
198.	2014	CT PURA	14-05-06	Connecticut Light and Power	Depreciation
199.	2014	MO PSC	ER-2014-0370	Kansas City Power & Light	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
200.	2014	KY PSC	2014-00371	Kentucky Utilities Company	Depreciation
201.	2014	KY PSC	2014-00372	Louisville Gas and Electric Company	Depreciation
202.	2015	PA PUC	R-2015-2462723	United Water Pennsylvania Inc.	Depreciation
203.	2015	PA PUC	R-2015-2468056	NiSource - Columbia Gas of Pennsylvania	Depreciation
204.	2015	NY PSC	15-E-0283/15-G-0284	New York State Electric and Gas Corporation	Depreciation
205.	2015	NY PSC	15-E-0285/15-G-0286	Rochester Gas and Electric Corporation	Depreciation
206.	2015	MO PSC	WR-2015-0301/SR-2015-0302	Missouri American Water Company	Depreciation
207.	2015	OK CC	PUD 201500208	Oklahoma, Public Service Company of	Depreciation
208.	2015	WV PSC	15-0676-W-42T	West Virginia American Water Company	Depreciation
209.	2015	PA PUC	2015-2469275	PPL Electric Utilities	Depreciation
210.	2015	IN URC	Cause No. 44688	Northern Indiana Public Service Company	Depreciation
211.	2015	OH PSC	14-1929-EL-RDR	First Energy-Ohio Edison/Cleveland Electric/ Toledo Edison	Depreciation
212.	2015	NM PRC	15-00127-UT	El Paso Electric	Depreciation
213.	2015	TX PUC	PUC-44941; SOAH 473-15-5257	El Paso Electric	Depreciation
214.	2015	WI PSC	3270-DU-104	Madison Gas and Electric Company	Depreciation
215.	2015	OK CC	PUD 201500273	Oklahoma Gas and Electric	Depreciation
216.	2015	KY PSC	Doc. No. 2015-00418	Kentucky American Water Company	Depreciation
217.	2015	NC UC	Doc. No. G-5, Sub 565	Public Service Company of North Carolina	Depreciation
218.	2016	WA UTC	Docket UE-17	Puget Sound Energy	Depreciation
219.	2016	NY PSC	Case No. 16-W-0130	SUEZ Water New York, Inc.	Depreciation
220.	2016	MO PSC	ER-2016-0156	KCPL – Greater Missouri	Depreciation
221.	2016	WI PSC		Wisconsin Public Service Corporation	Depreciation
222.	2016	KY PSC	Case No. 2016-00026	Kentucky Utilities Company	Depreciation
223.	2016	KY PSC	Case No. 2016-00027	Louisville Gas and Electric Company	Depreciation
224.	2016	OH PUC	Case No. 16-0907-WW-AIR	Aqua Ohio	Depreciation
225.	2016	MD PSC	Case 9417	NiSource - Columbia Gas of Maryland	Depreciation
226.	2016	KY PSC	2016-00162	Columbia Gas of Kentucky	Depreciation
227.	2016	DE PSC	16-0649	Delmarva Power and Light Company – Electric	Depreciation
228.	2016	DE PSC	16-0650	Delmarva Power and Light Company – Gas	Depreciation
229.	2016	NY PSC	Case 16-G-0257	National Fuel Gas Distribution Corp – NY Div	Depreciation
230.	2016	PA PUC	R-2016-2537349	Metropolitan Edison Company	Depreciation
231.	2016	PA PUC	R-2016-2537352	Pennsylvania Electric Company	Depreciation
232.	2016	PA PUC	R-2016-2537355	Pennsylvania Power Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
233.	2016	PA PUC	R-2016-2537359	West Penn Power Company	Depreciation
234.	2016	PA PUC	R-2016-2529660	NiSource - Columbia Gas of PA	Depreciation
235.	2016	KY PSC	Case No. 2016-00063	Kentucky Utilities / Louisville Gas & Electric Co	Depreciation
236.	2016	MO PSC	ER-2016-0285	KCPL Missouri	Depreciation
237.	2016	AR PSC	16-052-U	Oklahoma Gas & Electric Co	Depreciation
238.	2016	PSCW	6680-DU-104	Wisconsin Power and Light	Depreciation
239.	2016	ID PUC	IPC-E-16-23	Idaho Power Company	Depreciation
240.	2016	OR PUC	UM1801	Idaho Power Company	Depreciation
241.	2016	ILL CC	16-	MidAmerican Energy Company	Depreciation
242.	2016	KY PSC	Case No. 2016-00370	Kentucky Utilities Company	Depreciation
243.	2016	KY PSC	Case No. 2016-00371	Louisville Gas and Electric Company	Depreciation
244.	2016	IN URC	Cause No. 45029	Indianapolis Power & Light	Depreciation
245.	2016	AL RC	U-16-081	Chugach Electric Association	Depreciation
246.	2017	MA DPU	D.P.U. 17-05	NSTAR Electric Company and Western Massachusetts Electric Company	Depreciation
247.	2017	TX PUC	PUC-26831, SOAH 973-17-2686	El Paso Electric Company	Depreciation
248.	2017	WA UTC	UE-17033 and UG-170034	Puget Sound Energy	Depreciation
249.	2017	OH PUC	Case No. 17-0032-EL-AIR	Duke Energy Ohio	Depreciation
250.	2017	VA SCC	Case No. PUE-2016-00413	Virginia Natural Gas, Inc.	Depreciation
251.	2017	OK CC	Case No. PUD201700151	Public Service Company of Oklahoma	Depreciation
252.	2017	MD PSC	Case No. 9447	Columbia Gas of Maryland	Depreciation
253.	2017	NC UC	Docket No. E-2, Sub 1142	Duke Energy Progress	Depreciation
254.	2017	VA SCC	Case No. PUR-2017-00090	Dominion Virginia Electric and Power Company	Depreciation
255.	2017	FERC	ER17-1162	MidAmerican Energy Company	Depreciation
256.	2017	PA PUC	R-2017-2595853	Pennsylvania American Water Company	Depreciation
257.	2017	OR PUC	UM1809	Portland General Electric	Depreciation
258.	2017	FERC	ER17-217-000	Jersey Central Power & Light	Depreciation
259.	2017	FERC	ER17-211-000	Mid-Atlantic Interstate Transmission, LLC	Depreciation
260.	2017	MN PUC	Docket No. G007/D-17-442	Minnesota Energy Resources Corporation	Depreciation
261.	2017	IL CC	Docket No. 17-0124	Northern Illinois Gas Company	Depreciation
262.	2017	OR PUC	UM1808	Northwest Natural Gas Company	Depreciation
263.	2017	NY PSC	Case No. 17-W-0528	SUEZ Water Owego-Nichols	Depreciation
264.	2017	MO PSC	GR-2017-0215	Laclede Gas Company	Depreciation
265.	2017	MO PSC	GR-2017-0216	Missouri Gas Energy	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
266.	2017	ILL CC	Docket No. 17-0337	Illinois-American Water Company	Depreciation
267.	2017	FERC	Docket No. ER18-22-000	PPL Electric Utilities Corporation	Depreciation
268.	2017	IN URC	Cause No. 44988	Northern Indiana Public Service Company	Depreciation
269.	2017	NJ BPU	BPU Docket No. WR17090985	New Jersey American Water Company, Inc.	Depreciation
270.	2017	RI PUC	Docket No. 4800	SUEZ Water Rhode Island	Depreciation
271.	2017	OK CC	Cause No. PUD 201700496	Oklahoma Gas and Electric Company	Depreciation
272.	2017	NJ BPU	ER18010029 & GR18010030	Public Service Electric and Gas Company	Depreciation
273.	2017	NC Util Com.	Docket No. E-7, SUB 1146	Duke Energy Carolinas, LLC	Depreciation
274.	2017	KY PSC	Case No. 2017-00321	Duke Energy Kentucky, Inc.	Depreciation
275.	2017	MA DPU	D.P.U. 18-40	Berkshire Gas Company	Depreciation
276.	2018	IN IURC	Cause No. 44992	Indiana-American Water Company, Inc.	Depreciation
277.	2018	IN IURC	Cause No. 45029	Indianapolis Power and Light	Depreciation
278.	2018	NC Util Com.	Docket No. W-218, Sub 497	Aqua North Carolina, Inc.	Depreciation
279.	2018	PA PUC	Docket No. R-2018-2647577	NiSource - Columbia Gas of Pennsylvania, Inc.	Depreciation
280.	2018	OR PUC	Docket UM 1933	Avista Corporation	Depreciation
281.	2018	WA UTC	Docket No. UE-108167	Avista Corporation	Depreciation
282.	2018	ID PUC	AVU-E-18-03, AVU-G-18-02	Avista Corporation	Depreciation
283.	2018	IN URC	Cause No. 45039	Citizens Energy Group	Depreciation
284.	2018	FERC	Docket No. ER18-	Duke Energy Progress	Depreciation
285.	2018	PA PUC	Docket No. R-2018-3000124	Duquesne Light Company	Depreciation
286.	2018	MD PSC	Case No. 948	NiSource - Columbia Gas of Maryland	Depreciation
287.	2018	MA DPU	D.P.U. 18-45	NiSource - Columbia Gas of Massachusetts	Depreciation
288.	2018	OH PUC	Case No. 18-0299-GA-ALT	Vectren Energy Delivery of Ohio	Depreciation
289.	2018	PA PUC	Docket No. R-2018-3000834	SUEZ Water Pennsylvania Inc.	Depreciation
290.	2018	MD PSC	Case No. 9847	Maryland-American Water Company	Depreciation
291.	2018	PA PUC	Docket No. R-2018-3000019	The York Water Company	Depreciation
292.	2018	FERC	ER-18-2231-000	Duke Energy Carolinas, LLC	Depreciation
293.	2018	KY PSC	Case No. 2018-00261	Duke Energy Kentucky, Inc.	Depreciation
294.	2018	NJ BPU	BPU Docket No. WR18050593	SUEZ Water New Jersey	Depreciation
295.	2018	WA UTC	Docket No. UE-180778	PacifiCorp	Depreciation
296.	2018	UT PSC	Docket No. 18-035-36	PacifiCorp	Depreciation
297.	2018	OR PUC	Docket No. UM-1968	PacifiCorp	Depreciation
298.	2018	ID PUC	Case No. PAC-E-18-08	PacifiCorp	Depreciation
299.	2018	WY PSC	20000-539-EA-18	PacifiCorp	Depreciation
300.	2018	PA PUC	Docket No. R-2018-3003068	Aqua Pennsylvania, Inc.	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
301.	2018	IL CC	Docket No. 18-1467	Aqua Illinois, Inc.	Depreciation
302.	2018	KY PSC	Case No. 2018-00294	Louisville Gas & Electric Company	Depreciation
303.	2018	KY PSC	Case No. 2018-00295	Kentucky Utilities Company	Depreciation
304.	2018	IN URC	Cause No. 45159	Northern Indiana Public Service Company	Depreciation
305.	2018	VA SCC	Case No. PUR-2019-00175	Virginia American Water Company	Depreciation
306.	2019	PA PUC	Docket No. R-2018-3006818	Peoples Natural Gas Company, LLC	Depreciation
307.	2019	OK CC	Cause No. PUD201800140	Oklahoma Gas and Electric Company	Depreciation
308.	2019	MD PSC	Case No. 9490	FirstEnergy – Potomac Edison	Depreciation
309.	2019	SC PSC	Docket No. 2018-318-E	Duke Energy Progress	Depreciation
310.	2019	SC PSC	Docket No. 2018-319-E	Duke Energy Carolinas	Depreciation
311.	2019	DE PSC	DE 19-057	Public Service of New Hampshire	Depreciation
312.	2019	NY PSC	Case No. 19-W-0168 & 19-W-	SUEZ Water New York	Depreciation
313.	2019	PA PUC	Docket No. R-2019-3006904	Newtown Artesian Water Company	Depreciation
314.	2019	MO PSC	ER-2019-0335	Ameren Missouri	Depreciation
315.	2019	MO PSC	EC-2019-0200	KCP&L Greater Missouri Operations Company	Depreciation
316.	2019	MN DOC	G011/D-19-377	Minnesota Energy Resource Corp.	Depreciation
317.	2019	NY PSC	Case 19-E-0378 & 19-G-0379	New York State Electric and Gas Corporation	Depreciation
318.	2019	NY PSC	Case 19-E-0380 & 19-G-0381	Rochester Gas and Electric Corporation	Depreciation
319.	2019	WA UTC	Docket UE-190529 / UG-190530	Puget Sound Energy	Depreciation
320.	2019	PA PUC	Docket No. R-2019-3010955	City of Lancaster	Depreciation
321.	2019	IURC	Cause No. 45253	Duke Energy Indiana	Depreciation
322.	2019	KY PSC	Case No. 2019-00271	Duke Energy Kentucky, Inc.	Depreciation
323.	2019	OH PUC	Case No. 18-1720-GA-AIR	Northeast Ohio Natural Gas Corp	Depreciation
324.	2019	NC Util. Com.	Docket No. E-2, Sub 1219	Duke Energy Carolinas	Depreciation
325.	2019	FERC	Docket No. ER20-277-000	Jersey Central Power & Light Company	Depreciation
326.	2019	MA DPU	D.P.U. 19-120	NSTAR Gas Company	Depreciation
327.	2019	SC PSC	Docket No. 2019-290-WS	Blue Granite Water Company	Depreciation
328.	2019	NC Util. Com.	Docket No. E-2, Sub 1219	Duke Energy Progress	Depreciation
329.	2019	MD PSC	Case No. 9609	NiSource Columbia Gas of Maryland, Inc.	Depreciation
330.	2020	NJ BPU	Docket No. ER20020146	Jersey Central Power & Light Company	Depreciation
331.	2020	PA PUC	Docket No. R-2020-3018835	NiSource - Columbia Gas of Pennsylvania, Inc.	Depreciation
332.	2020	PA PUC	Docket No. R-2020-3019369	Pennsylvania-American Water Company	Depreciation
333.	2020	PA PUC	Docket No. R-2020-3019371	Pennsylvania-American Water Company	Depreciation
334.	2020	MO PSC	GO-2018-0309, GO-2018-0310	Spire Missouri, Inc.	Depreciation
335.	2020	NM PRC	Case No. 20-00104-UT	El Paso Electric Company	Depreciation
336.	2020	MD PSC	Case No. 9644	Columbia Gas of Maryland, Inc.	Depreciation
337.	2020	MO PSC	GO-2018-0309, GO-2018-0310	Spire Missouri, Inc.	Depreciation
338.	2020	VA St CC	Case No. PUR-2020-00095	Virginia Natural Gas Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
339.	2020	SC PSC	Docket No. 2020-125-E	Dominion Energy South Carolina, Inc.	Depreciation
340.	2020	WV PSC	Case No. 20-0745-G-D	Hope Gas, Inc. d/b/a Dominion Energy West Virginia	Depreciation
341.	2020	VA St CC	Case No. PUR-2020-00106	Aqua Virginia, Inc.	Depreciation
342.	2020	PA PUC	Docket No. R-2020-3020256	City of Bethlehem – Bureau of Water	Depreciation
343.	2020	NE PSC	Docket No. NG-109	Black Hills Nebraska	Depreciation
344.	2020	NY PSC	Case No. 20-E-0428 & 20-G-0429	Central Hudson Gas & Electric Corporation	Depreciation
345.	2020	FERC	ER20-598	Duke Energy Indiana	Depreciation
346.	2020	FERC	ER20-855	Northern Indiana Public Service Company	Depreciation
347.	2020	OR PSC	UE 374	PacifiCorp	Depreciation
348.	2020	MD PSC	Case No. 9490 Phase II	Potomac Edison – Maryland	Depreciation
349.	2020	IN URC	Case No. 45447	Southern Indiana Gas and Electric Company	Depreciation
350.	2020	IN URC	IURC Cause No. 45468	Indiana Gas Company, Inc. d/b/a Vectren Energy Delivery of	Depreciation
351.	2020	KY PSC	Case No. 2020-00349	Kentucky Utilities Company	Depreciation
352.	2020	KY PSC	Case No. 2020-00350	Louisville Gas and Electric Company	Depreciation
353.	2020	FERC	Docket No. ER21- 000	South FirstEnergy Operating Companies	Depreciation
354.	2020	OH PUC	Case Nos 20-1651-EL-AIR, 20-1652-EL-AAM & 20-1653-EL-ATA	Dayton Power and Light Company	Depreciation
355.	2020	OR PSC	UG 388	Northwest Natural Gas Company	Depreciation
356.	2020	MO PSC	Case No. GR-2021-0241	Ameren Missouri Gas	Depreciation
357.	2021	KY PSC	Case No. 2021-00103	East Kentucky Power Cooperative	Depreciation
358.	2021	MPUC	Docket No. 2021-00024	Bangor Natural Gas	Depreciation
359.	2021	PA PUC	Docket No. R-2021-3024296	Columbia Gas of Pennsylvania, Inc.	Depreciation
360.	2021	NC Util. Com.	Doc. No. G-5, Sub 632	Public Service of North Carolina	Depreciation
361.	2021	MO PSC	ER-2021-0240	Ameren Missouri	Depreciation
362.	2021	PA PUC	Docket No. R-2021-3024750	Duquesne Light Company	Depreciation
363.	2021	KS PSC	21-BHCG-418-RTS	Black Hills Kansas Gas	Depreciation
364.	2021	KY PSC	Case No. 2021-00190	Duke Energy Kentucky	Depreciation
365.	2021	OR PSC	Docket UM 2152	Portland General Electric	Depreciation
366.	2021	ILL CC	Docket No. 20-0810	North Shore Gas Company	Depreciation
367.	2021	FERC	ER21-1939-000	Duke Energy Progress	Depreciation
368.	2021	FERC	ER21-1940-000	Duke Energy Carolina	Depreciation
369.	2021	KY PSC	Case No. 2021-00183	NiSource Columbia Gas of Kentucky	Depreciation
370.	2021	MD PSC	Case No. 9664	NiSource Columbia Gas of Maryland	Depreciation
371.	2021	OH PUC	Case No. 21-0596-ST-AIR	Aqua Ohio	Depreciation
372.	2021	PA PUC	Docket No. R-2021-3026116	Hanover Borough Municipal Water Works	Depreciation
373.	2021	OR PSC	UM-2180	Idaho Power Company	Depreciation
374.	2021	ID PUC	Case No. IPC-E-21-18	Idaho Power Company	Depreciation
375.	2021	WPSC	6690-DU-104	Wisconsin Public Service Company	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
376.	2021	PAPUC	Docket No. R-2021-3026116	Borough of Hanover	Depreciation
377.	2021	OH PUC	Case No. 21-637-GA-AIR; Case No. 21-638-GA-ALT; Case No. 21-639-GA-UNC; Case No. 21-640-GA-AAM	NiSource Columbia Gas of Ohio	Depreciation
378.	2021	TX PUC	Texas PUC Docket No. 52195; SOHA Docket No. 473-21-2606	El Paso Electric	Depreciation
379.	2021	MO PSC	Case No. GR.2021-0108	Spire Missouri	Depreciation
380.	2021	WV PSC	Case No. 21-0215-WS-P	West Virginia American Water Company	Depreciation
381.	2021	FERC	ER21-2736	Duke Energy Carolinas	Depreciation
382.	2021	FERC	ER21-2737	Duke Energy Progress	Depreciation
383.	2021	IN URC	Cause #45621	Northern Indiana Public Service Company	Depreciation
384.	2021	PA PUC	Docket No. R-2021-3026682	City of Lancaster	Depreciation
385.	2021	OH PUC	Case No. 21-887-EL-AIR; Case No. 21-888-EL-ATA; Case No. 889-El-AAM	Duke Energy Ohio	Depreciation
386.	2021	AK PSC	Docket No. 21-097-U	Black Hills Energy Arkansas, Inc.	Depreciation
387.	2021	OK CC	Cause No. PUD202100164	Oklahoma Gas & Electric	Depreciation
388.	2021	FERC	Case ER-22-392-001	El Paso Electric	Depreciation
389.	2021	FERC	Case ER-21-XXX	MidAmerican Electric	Depreciation
390.	2021	PA PUC	Docket Nos. R-2021-3027385, R-2021-3027386	Aqua Pennsylvania, Inc. Aqua Pennsylvania Wastewater, Inc.	Depreciation
391.	2022	FERC	Case ER-22-282-000	El Paso Electric	Depreciation
392.	2022	ILL CC	Docket No. 22-0154	MidAmerican Gas	Depreciation
393.	2022	MO PSC	Case No. ER-2022-0129	Evergy Metro	Depreciation
394.	2022	MO PSC	Case No. ER-2022-0130	Evergy Missouri West	Depreciation
395.	2022	PA PUC	Docket No. R-2022-3031211	NiSource Columbia Gas of Pennsylvania, Inc.	Depreciation
396.	2022	MA DPU	D.P.U. 22-20	The Berkshire Gas Company	Depreciation
397.	2022	PA PUC	R-2022-3031672; R-2022-	Pennsylvania-American Water Company	Depreciation
398.	2022	SD PUC	Docket No. NG22-	MidAmerican Gas	Depreciation
399.	2022	MD PSC	Case No. 9680	NiSource Columbia Gas of Maryland	Depreciation
400.	2022	WYPSC	Docket No. 20003-214-ER-22	Black Hills Energy – Cheyenne Light, Fuel and Power Company	Depreciation
401.	2022	MA DPU	D.P.U. 22.22	NSTAR Electric Company d/b/a Eversource Energy	Depreciation
402.	2022	NC Util Com	Docket No. W-218, Sub 573	Aqua North Carolina, Inc.	Depreciation
403.	2022	OR PUC	UM2213	Northwest Natural Gas	Depreciation
404.	2022	OR PUC	UM2214	Northwest Natural Gas	Depreciation
405.	2022	ME PUC	Docket No. 2022-00152	Central Maine Power	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
406.	2022	SC PSC	Docket No. 2022-254-E	Duke Energy Progress	Depreciation
407.	2022	NC Util Com	Docket No. E-2, SUB 1300	Duke Energy Progress	Depreciation
408.	2022	IN URC	Cause #45772	Northern Indiana Public Service Company	Depreciation
409.	2022	PA PUC	R-2022-3031340	The York Water Company	Depreciation
410.	2022	PA PUC	R-2022-3032806	The York Water Company	Depreciation
411.	2022	PA PUC	R-2022-3031704	Borough of Ambler	Depreciation
412.	2022	MO PSC	ER-2022-0337	Ameren Missouri	Depreciation
413.	2022	OH PUC	Case No. 22-507-GA-AIR	Duke Energy Ohio	Depreciation
414.	2022	PA PUC	R-2022-3035730	National Fuel Gas Distribution Corporation – PA Division	Depreciation
415.	2022	WY PSC	20003-214-ER-22	Cheyenne Light, Fuel and Power Company	Depreciation
416.	2022	KY PSC	Case No. 2022-00372	Duke Energy Kentucky	Depreciation
417.	2022	TX PUC	SOAH Docket No. 473-23-04521	Aqua Texas, Inc.	Depreciation
418.	2022	NC Util Com	Docket No. E-7, Sub 1276	Duke Energy Carolinas, LLC	Depreciation
419.	2022	KY PSC	Case No. 2022-00432	Bluegrass Water	Depreciation
420.	2023	ILL CC	Docket No. 23-0069	The Peoples Gas Light and Coke Company	Depreciation
421.	2023	ILL CC	Docket No. 23-0068	North Shore Gas Company	Depreciation
422.	2023	WV PSC	Case No. 23-0030-E-D	Monongahela Power Company and The Potomac Edison Company	Depreciation
423.	2023	ID PUC	AVU-E-23-01; AVU-G-23-01	Avista Corporation	Depreciation
424.	2023	ILL CC	Docket No. 23-	Northern Illinois Gas Company d/b/a Nicor Gas Company	Depreciation

EXHIBIT JC-11

BEFORE THE
NEW JERSEY BOARD OF PUBLIC UTILITIES

In the Matter of the Verified Petition of Jersey Central Power & Light Company for Review and Approval of Increases in and Other Adjustments to Its Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith

Direct Testimony

of

Timothy S. Lyons

on

Cash Working Capital

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EXHIBIT JC-11

DIRECT TESTIMONY OF TIMOTHY S. LYONS ON BEHALF OF JERSEY CENTRAL POWER & LIGHT COMPANY

I. Introduction and Qualifications

Q. Please state your name and business address.

A. My name is Timothy S. Lyons. My business address is 3 Speen Street, Suite 150 Framingham, MA 01701.

Q. Please describe your current position.

A. I am a Partner at ScottMadden, Inc. ("ScottMadden").

Q. Please describe your work experience.

A. I have more than 30 years of experience in the energy industry. I started my career in 1985 at Boston Gas Company, eventually becoming Director of Rates and Revenue Analysis. In 1993, I moved to Providence Gas Company, eventually becoming Vice President of Marketing and Regulatory Affairs. Starting in 2001, I held several management consulting positions in the energy industry first at KEMA and then at Quantec, LLC. In 2005, I became Vice President of Sales and Marketing at Vermont Gas Systems, Inc. before joining Sussex Economic Advisors, LLC ("Sussex") in 2013. Sussex was acquired by ScottMadden in 2016.

Q. Please describe your educational background.

A. I hold a bachelor's degree from St. Anselm College, a master's degree in Economics from The Pennsylvania State University, and a master's degree in Business Administration from Babson College.

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

A. Yes. A summary of my testimony experience is included as Appendix A.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to sponsor the results of the lead-lag study conducted on behalf of Jersey Central Power & Light Company ("JCP&L" or the "Company"), a subsidiary of FirstEnergy. The lead-lag study is submitted as part of the Company's March 2023 base rate filing with the Board. The lead-lag study was used to determine the Company's Cash Working Capital ("CWC") requirement, which is included in the Company's rate base.

Q. Are you sponsoring schedules in connection with your testimony?

A. Yes. I am sponsoring the following schedules that were prepared by me or under my direction:

- Schedule TSL-1 – Summary of the Cash Working Capital Requirement; and
- Schedule TSL-2 – Workpapers supporting the Lead-Lag Study.

II. Overview of Testimony

Q. Please define the term "working capital" as a rate base component.

A. The term "working capital" refers to the net funds required by the Company to finance goods and services used to provide service to customers from the time those goods and services are paid for by the Company to the time that payment is received from customers. Goods and services considered in the lead-lag study include: operations and maintenance

("O&M") expenses, including labor and non-labor expenses; federal, state, and local taxes; and employment taxes.

Q. How was the Company's cash working capital requirement determined?

A. The Company's cash working capital requirement was determined by applying the results of the lead-lag study to 6 months of historical test year expenses (July 1, 2022 through December 31, 2022) and 6 months of forecasted test year expenses (January 1, 2023 through June 30, 2023). The lead-lag study compares differences between the Company's revenue lag and expense leads.

The revenue lag represents the number of days from the time customers receive their electric service to the time customers pay for their electric service, *i.e.*, when the funds are available to the Company. The longer the revenue lag, the more cash the Company needs to finance its day-to-day operations.

The expense lead represents the number of days from the time the Company receives goods and services used to provide electric service to the time payments are made for those goods and services, *i.e.*, when the funds are no longer available to the Company. The longer the expense lead, the less cash the Company needs to fund its day-to-day operations.

Together, the revenue lag and expense leads are used to measure the lead-lag days. The lead-lag days are then applied to the Company's 6 months of historical test year expenses (July 1, 2022 through December 31, 2022) and 6 months of forecasted test year expenses (January 1, 2023 through June 30, 2023) to derive the CWC requirement, which is included in the Company's rate base.

Unless otherwise indicated, the approach to calculate the CWC requirement in this rate case filing is consistent with the approach used in the prior rate case filing.[1]

III. Lead-Lag Study Approach

Q. Please describe the data used in the lead-lag study.

A. The lead-lag study was based on data from the period January 1, 2021 through December 31, 2021 (the "study period"). The data included: customer meter reading and billing schedules; O&M expenses; and federal, state, local, and employment taxes. The data generally included service periods, payment dates, and payment amounts.

1. Revenue Lag

Q. How was the revenue lag determined?

A. The revenue lag was based on the number of days from the time electric service was provided to customers, to the time payment was received from customers. There are two categories of revenues that comprise the revenue lag: (1) retail electricity revenues, and (2) other operating revenues.

Retail electricity revenues represent the largest revenue category, consisting of revenues related to retail electricity service for residential, commercial, and industrial customers. The revenue lag for retail electricity service was measured as the sum of three components: (1) the service lag; (2) the billing lag; and (3) the collection lag.

[1] The Stipulation of Settlement, dated October 15, 2020, was approved by the New Jersey Board of Public Utilities on October 28, 2020 (BPU Docket No. ER20020146, OAL Docket No. PUC 04343-2020N)

Q. What is the service lag?

A. The service lag measures the average number of days in the service period; *i.e.*, the time between the start and end of the billing month. Meters are read at the end of the billing month. The service lag in this lead-lag study was based on the midpoint of the service period, which reflects that electricity is delivered evenly over the service period.

Q. What is the billing lag?

A. The billing lag measures the number of days from the time meters are read to the time bills are calculated and recorded. The billing lag in this lead-lag study was based on the Company's meter reading schedule.

Q. What is the collection lag?

A. The collection lag measures the number of days from the time bills are calculated and recorded to the time customer payments are received (*i.e.*, funds are available to the Company). The collection lag in this lead-lag study was based on monthly accounts receivable balances and billed revenue data. Specifically, the collection lag was determined by dividing the average accounts receivable balance during the study period by the average billed revenues per day during the same period. The approach is consistent with the Company's lead-lag study filed in the Company's most recent rate case, which was the JCP&L 2020 Base Rate Case.

Q. How was the revenue lag for other operating revenues determined?

A. The revenue lag for other operating revenues was determined by first identifying the revenue lag for each of the five categories of other operating revenues; second converting the revenue lags to "dollar-days" that reflect a weighting of the categories by revenues; and

finally summing the dollar days across all other operating revenues. The five categories of other operating revenues were: (1) wholesale energy revenues, (2) Solar Renewable Energy Certificates ("SREC") sales revenues, (3) other retail revenues, such as late payment and miscellaneous services charges, (4) telecom and telephone pole rentals, and (5) intercompany revenues.

Q. What is the total revenue lag used in the lead-lag study?

A. The total revenue lag used in the lead-lag study is based on a weighted average of the revenue lags for retail electricity revenues and other operating revenues. The derivation of the revenue lag is shown in Schedule TSL-2 at page 1.

2. Expense Leads

a. Operation and Maintenance Expenses

Q. Please describe the development of lead days for O&M expenses.

A. Lead days for O&M expenses were measured separately for the following expense categories: (1) purchased energy; (2) regular payroll; (3) incentive compensation; (4) employee benefits; (5) pension; (6) service company (affiliate); (7) joint use rental; (8) uncollectible expenses; (9) universal service fund/lifeline payments; and (10) other O&M expenses.

Q. How were lead days determined for purchased energy expenses?

A. Lead days for purchased energy expenses were measured separately for the following categories: (a) purchased energy; and (2) Zero Emissions Credits ("ZEC").

Lead days for purchased energy were based on a review of the Company's invoices. Lead days were measured as the number of days from the midpoint of the service period to the payment date.

Lead days for ZECs were zero to reflect the interest payments that offset timing differences between the midpoint of the service period and the payment date.

Q. How were lead days determined for regular payroll expenses?

A. Lead days for regular payroll expenses were based on the Company's payroll process, which pays employees on a weekly and bi-weekly basis. Lead days were measured for each payroll period as the number of days from the midpoint of the weekly and bi-weekly payroll period, individually, to the weekly and bi-weekly payment date, converted to "dollar-days" to reflect a weighting of the expense amounts, and then summed across all regular payroll expenses.

Q. Did the study separately determine lead days for incentive compensation expenses?

A. Yes. Lead days for the Company's incentive compensation expenses were measured separately as the number of days from the midpoint of the performance period (*i.e.*, when the incentive compensation was earned) to the payment dates.

Q. How were lead days determined for employee benefit expenses?

A. Lead days for employee benefit expenses were based on a review of the Company's payments for individual benefit items, including medical, dental, and 401(k) plans. Lead days were measured for each benefit item as the number of days from the midpoint of the benefit period to the payment date, converted to "dollar-days" to reflect a weighting of the expense amounts, and then summed across all benefit expenses.

Q. How were lead days determined for pension plan payments?

A. Lead days for pension plan payments were zero to reflect that services are provided to the pension plan at the time payment is made.

Q. How were lead days determined for FirstEnergy Services Company (Affiliate) expenses?

A. Lead days for FirstEnergy Services Company (Affiliate) ("FESC") expenses were based on the number of days from the midpoint of the service period to the financial settlement (payment) date via the money pool. The FESC service period is based on the calendar month. Intercompany charges are recorded during the month and are billed by FESC and settled by the various FirstEnergy companies on the first business day following the conclusion of the service period. Lead days for FESC expenses were measured as the number of days from midpoint of the service period to the financial settlement via the money pool, which is on the first business day following the conclusion of the service period.

Q. How were lead days determined for joint use rentals?

A. Lead days for Joint Use rentals were based on the service periods and payment schedule. Lead days for Joint Use rentals were measured as the number of days from midpoint of the service period to the payment date.

Q. How were lead days determined for uncollectible expenses?

A. Lead days for uncollectible expenses were based on the Company's approach to create a reserve account for uncollectible expenses prior to the actual write-off. Lead days were

measured as the average uncollectible reserve balance over the past thirteen months divided by the actual write-off expenses during the study period and then multiplied by 365 days.

Q. How were lead days determined for universal service fund/ lifeline payments?

A. Lead days for universal service fund/ lifeline payments were based on the collection periods and payment schedule. Lead days for universal service fund/lifeline payments were measured as the number of days from midpoint of the collection period to the payment date.

Q. How were lead days determined for Other O&M expenses?

A. Lead days for Other O&M expenses were based on the sum of two components: (1) lead days from the midpoint of the service period to the invoice date; and (2) lead days from the invoice date to the payment date.

Lead days from the midpoint of the service period to the invoice date were based on a stratified sample of invoices paid by the Company over the period January 1, 2021 through December 31, 2021. Lead days were measured for each invoice in the sample as the number of days from the midpoint of the service period to the invoice date. Invoices were then converted to "dollar days" to reflect a weighting by expense amount and then summed by invoice amounts to determine the lead days. The study relied on a sample of invoices to measure the lead days because the service periods were not readily available electronically and required detailed inspection of individual invoices.

Lead days from the invoice date to the payment date were based on the full population of invoices paid by the Company over the period January 1, 2021 through December 31, 2021. Lead days were measured for each invoice as the number of days

from the invoice date to the payment date. Invoices were then converted to "dollar days" to reflect a weighting by expense amount and then summed by invoice amounts to determine the lead days.

The approach is a change from the approach used in the Company's most recent lead-lag study, adding greater precision to the study. Specifically, the current study is based on actual invoices during the test year while the prior study was based on standard payment terms of 45 days.

b. Current Income Tax Expense

Q. How were lead days determined for federal income taxes?

A. Lead days for federal income taxes were based on due dates for tax payments: April 15, June 15, September 15, and December 15. Lead days for federal income taxes were measured as the number of days from the midpoint of the taxing period (*i.e.*, the calendar year) to the due dates. The study assumes the tax payments reflect equal installments.

Q. How were lead days determined for state income taxes?

A. Lead days for state income taxes were based on due dates for tax payments: April 15, May 15, and June 15. Lead days for state income taxes were measured as the number of days from the midpoint of the taxing period (*i.e.*, the calendar year) to the due dates. The study assumes the tax payments reflect the following installments: 25.0 percent is due on April 15, 50.0 percent is due on May 15 and 25.0 percent is due on June 15.

c. Taxes Other than Income Taxes

Q. How were lead days determined for Taxes Other Than Income Taxes?

A. Lead days for Taxes Other Than Income Taxes were measured separately for the following categories: (1) payroll-related taxes (FICA, federal unemployment, and state unemployment); (2) real estate; (3) sales and use taxes; and (4) New Jersey Public Utility Assessment and Ratepayer Advocate Assessment.

Q. How were lead days determined for each of these taxes?

A. Lead days for FICA taxes were measured as the number of days from the midpoint of the applicable pay period to the payment date.

Lead days for federal and state unemployment taxes were measured as the number of days from the midpoint of the taxing period to the due date.

Lead days for real estate taxes were measured as the number of days from the midpoint of the taxing period to the payment date.

Lead days for sales and use taxes were measured as the number of days from the midpoint of the taxing period to the payment date.

Lead days for New Jersey Public Utility Assessment and Ratepayer Advocate Assessment were measured as the number of days from the midpoint of the assessment period to the payment date.

d. Return on Invested Capital and Interest Expenses

Q. Did you calculate lead days for return on invested capital and interest payments?

A. Yes. The Board's practice is to include the return on invested capital in the lead-lag study.[2]

[2] *See* "Order Adopting Initial Decision with Modifications and Clarifications," BPU Docket No. ER12111052, March 26, 2015, at 14.

Lead days for return on common equity were zero, recognizing returns are earned and become the property of the utility's investors at the time services are rendered.

Lead days for interest payments related to long-term debt were measured as the number of days from the midpoint of the service period to the payment date for the study period.

Lead days for interest on customer deposits were measured as the midpoint of the service period of 1 year for Residential customers and of the service period of 2 years for Non-Residential customers.

e. Deferred Income Taxes

Q. Did you calculate lead days for deferred income taxes?

A. No. It has been the Board's practice to exclude deferred taxes from lead-lag studies.[3]

f. Depreciation and Other Expense Items

Q. Did you calculate lead days for depreciation expense?

A. Yes. The Board's practice is to include depreciation expense in the lead-lag study.[4]

Lead days for depreciation expenses were zero because the items are deducted from rate base when the expenses are recorded.

[3] Ibid., at 13-14.
[4] Ibid., at 13.

3. Working Capital Adjustments

Q. Please describe the working capital adjustments.

A. There were three working capital adjustments to be included in rate base. The adjustments were consistent with those in the study filed in the prior rate case. The categories of these adjustments are outlined below.

- Regulatory Debits – represents funds to be paid by customers.
- Regulatory Credits – represents funds owed to customers.
- Accretion Expense – represents funds to be paid by customers.

IV. Conclusion

Q. What were the results of the lead-lag study?

A. The results of the lead-lag study are included in Schedule TSL-1. Based on the study results, the Company's cash working capital requirement is $107,271,360.

Q. Are the results of this lead-lag study reasonable?

A. Yes, the study provides an accurate assessment of the Company's actual cash working capital requirements. The resulting cash working capital requirement should be included in the Company's rate base.

Q. Does this conclude your testimony?

A. Yes, it does.

Jersey Central Power & Light Company
2021 Lead-Lag Study
Working Capital Requirement
Summary

Line	Description	6+6 Forecast Total Company	6+6 Forecast Less: Transmission	6+6 Forecast Net of Transmission	6+6 Forecast Adjustments	6+6 Forecast Revenue Requirements	Average Daily Expenses	Revenue Lag	Ref.	Expense Lead	Ref.	Net (Lead) / Lag Days	Working Capital Requirement
		Column a	Column b	Column c = a-b	Column d	Column e = c+d							
1	**Operations and Maintenance Expenses**												
2	Energy Purchases	$ 1,016,362,676	$ -	$ 1,016,362,676	$ -	$ 1,016,362,676	$ 2,784,555	47.35	A	(34.24)	B	13.10	$ 36,481,924
3	BGS/NGC Deferral	(38,324,768)	-	(38,324,768)	-	(38,324,768)	(104,999)	47.35	A	0.00	B	47.35	(4,971,240)
4	Regular Payroll	81,754,938	6,910,600	74,844,338	5,281,433	80,125,772	219,523	47.35	A	(8.28)	C	39.07	8,576,541
5	Incentive Compensation	10,702,181	904,334	9,797,847	-	9,797,847	26,843	47.35	A	(233.00)	C	(185.65)	(4,983,603)
6	Employee Benefits	27,774,021	2,346,905	25,427,117	-	25,427,117	69,663	47.35	A	(34.71)	C	12.63	879,881
7	Pension/OPEB	4,722,679	399,066	4,323,613	24,121,045	28,444,658	77,931	47.35	A	0.00	C	47.35	3,689,657
8	Service Company	107,197,116	9,058,156	98,138,960	1,126,323	99,265,283	271,960	47.35	A	(16.71)	C	30.64	8,332,056
9	Joint Use Rental	3,791,923	-	3,791,923	-	3,791,923	10,389	47.35	A	(433.23)	C	(385.89)	(4,008,912)
10	Uncollectibles	11,608,543	-	11,608,543	-	11,608,543	31,804	47.35	A	(312.97)	C	(265.63)	(8,448,047)
11	Universal Service Fund/ Lifeline Payments	72,417,218	-	72,417,218	-	72,417,218	198,403	47.35	A	(22.26)	C	25.09	4,977,612
12	Other O&M Expenses	257,963,007	55,291,478	202,671,529	11,482,143	214,153,672	586,722	47.35	A	(54.10)	C	(6.75)	(3,962,966)
13	**Total O&M Expenses**	$ 1,555,969,536	$ 74,910,540	$ 1,481,058,996	$ 42,010,944	$ 1,523,069,940	$ 4,172,794						$ 36,562,902
14	**Income Taxes**												
15	Federal	$ 13,910,146	$ (24,671,794)	$ 38,581,940	$ (39,580,975)	$ (999,034)	$ (2,737)	47.35	A	(37.00)	D	10.35	$ (28,316)
16	State	11,925,653	(6,244,805)	18,170,459	(15,461,671)	2,708,788	7,421	47.35	A	47.25	D	94.60	702,025
17	**Total Income Taxes**	$ 25,835,799	$ (30,916,600)	$ 56,752,399	$ (55,042,645)	$ 1,709,753	$ 4,684						$ 673,708
18	**Taxes Other Than Income Taxes**	$ 10,341,001	$ 1,823,301	$ 8,517,700	$ 399,901	$ 8,917,601	$ 24,432	47.35	A	(1.45)	E	45.89	$ 1,121,248
19	**NJ Sales and Use Tax**	$ 128,393,076	$ 7,394,908	$ 120,998,167	$ -	$ 120,998,167	$ 331,502	47.35	A	51.53	F	98.87	$ 32,775,932
20	**NJBPU/Rate Counsel Annual Assessment**	$ 2,319,114	$ 36,259	$ 2,282,856	$ 843,045	$ 3,125,901	$ 8,564	47.35	A	(117.76)	G	(70.42)	$ (603,050)
21	**Depreciation and Amortization**	$ 217,878,450	$ 37,389,420	$ 180,489,030	$ 13,891,594	$ 194,380,624	$ 532,550	47.35	A	0.00		47.35	$ 25,213,794
22	**Interest Expense**												
23	Interest on Long-Term Debt	$ 96,450,000	$ 30,751,036	$ 65,698,964	$ -	$ 65,698,964	$ 179,997	47.35	A	(90.60)	H	(43.25)	$ (7,785,028)
24	Interest on Customer Deposits	28,844	$ -	28,844	$ 517,477	546,321	1,497	47.35	A	(260.72)	H	(213.37)	(319,372)
25	**Total Interest Expense**	$ 96,478,844	$ 30,751,036	$ 65,727,809	$ 517,477	$ 66,245,286	$ 181,494						$ (8,104,400)
26	**Return**	$ 305,419,641	$ 78,370,000	$ 227,049,641	$ -	$ 227,049,641	$ 622,054	47.35	A	(22.00)		25.35	$ 15,766,224
27	**Other Adjustments**												
28	Regulatory Debits	$ 45,491,399	$ -	$ 45,491,399	33,422,086	$ 78,913,485	216,201	47.35	A	0.00		47.35	$ 10,236,146
29	Regulatory Credits	(49,888,170)	$ -	(49,888,170)	367,396	(49,520,774)	(135,673)	47.35	A	0.00		47.35	(6,423,514)
30	Accretion Expense	403,950	$ -	403,950	-	403,950	1,107	47.35	A	0.00		47.35	52,398
31	**Total Other Adjustments**	$ (3,992,821)	$ -	$ (3,992,821)	$ 33,789,482	$ 29,796,661	$ 81,635						$ 3,865,030
32	**Cash Working Capital Requirement**	$ 2,338,642,640	$ 199,758,864	$ 2,138,883,776	$ 36,409,799	$ 2,175,293,575	$ 5,959,708						$ 107,271,360

Jersey Central Power & Light Company
2021 Lead-Lag Study
Revenue Lag

Line	Description	Company Revenues	Adjustments	Adjusted Company Revenues	Transmission Revenues	Net of Transmission	(Lead)/Lag Days	Reference	Dollar Days
1	Electric Revenues	$ 1,950,301,454	$ (12,292,767)	$ 1,938,008,687	$ 111,621,258	$1,826,387,429	47.03	WP A-1	$ 85,890,434,814
2	NJ Sales & Use Tax	-	128,393,076	128,393,076	7,394,908	120,998,167	47.03	WP A-1	5,690,241,306
3	Other Revenues	$ 127,248,980	(2,352,171)	124,896,809	98,678,342	26,218,467	70.96	WP A-2	1,860,464,385
4	Total Operating Revenues	$ 2,077,550,434	$ 113,748,138	$ 2,191,298,572	$ 217,694,509	$1,973,604,063	47.35		$ 93,441,140,505

[1] NJ Sales & Use Tax Rate of: 6.625%

Jersey Central Power & Light Company
2021 Lead-Lag Study
Energy Purchases

Line	Description	Payments ($000)	Expense Lead	(Lead)/ Lag Dollars	Reference
1	Energy Purchases	$ 849,336	(37.47)	$ (31,821,705)	WP (B)
2	Zero Emission Credits (ZEC)	79,930	0.00	-	WP (B)
3	Total	$ 929,266	(34.24)	$ (31,821,705)	

Jersey Central Power & Light Company
2021 Lead-Lag Study
O&M Expenses Summary

Line	Description	(Lead)/Lag Days	Reference
1	Regular Payroll	(8.28)	WP C-1
2	Incentive Compensation	(233.00)	WP C-2
3	Benefits	(34.71)	WP C-3
4	Pension	-	WP C-4
5	Service Company	(16.71)	WP C-5
6	Joint Use Rental Expenses	(433.23)	WP C-6
7	Uncollectibles	(312.97)	WP C-7
8	Universal Service Fund/ Lifeline Payments	(22.26)	WP C-8
9	Other O&M Expenses	(54.10)	WP C-8

Jersey Central Power & Light Company
2021 Lead-Lag Study
Income Taxes

Line	Description	(Lead)/Lag Days
1	Income Taxes	
2	Federal Income Taxes	(37.00)
3	State Income Taxes	47.25

Jersey Central Power & Light Company
2021 Lead-Lag Study
Taxes Other Than Income Taxes

Line	Description		Expense	(Lead)/Lag Days	Reference		Dollar Days
1	Payroll Taxes						
2	FICA	$	12,340,613	(10.21)	E-1	$	(126,032,759)
3	Federal Unemployment		61,326	(30.07)	E-2		(1,844,101)
4	State Unemployment		418,912	(29.93)	E-3		(12,536,194)
5	Total Payroll Taxes - Regular Payroll	$	12,820,851	(10.95)		$	(140,413,054)
6	NJ Property Tax	$	6,432,111	17.75	E-4	$	114,141,015
7	Other Taxes		(21,490)	77.26	E-5		(1,660,336)
8	Total	$	19,231,471	(1.45)		$	(27,932,375)

Jersey Central Power & Light Company
2021 Lead-Lag Study
Sales and Use Taxes

Line	Description	Expense	(Lead)/Lag Days	Reference	Dollar Days
1	Sales Tax	$ 111,564,524	52.49	F-1	$ 5,855,658,179
2	Use Tax	1,353,276	(27.71)	F-2	(37,499,368)
3	Sales & Use Tax	$ 112,917,801	51.53		$ 5,818,158,812

Jersey Central Power & Light Company
2021 Lead-Lag Study
Annual Assessment

Line	Description	Service Period Start	Service Period End	Mid-Point	Payment Date	Payment Amount	Total (Lead)/Lag Days	Dollar Days
1	NJBPU Annual Assessment	7/1/2020	6/30/2021	(182.50)	4/28/2021	$ 1,765,359	(119.50)	$ (210,960,391)
2	Rate Counsel Annual Assessment	7/1/2020	6/30/2021	(182.50)	4/19/2021	422,704	(110.50)	(46,708,835)
3	Total					$ 2,188,063	(117.76)	$ (257,669,226)

Jersey Central Power & Light Company
Lead-Lag Study
Interest Expense

Line	Description	(Lead)/Lag Days	Ref.
1	Long-Term Debt	(90.60)	H-1
2	Interest on Customer Deposits	(260.72)	H-2

Summary of Qualifications

Tim Lyons is a partner with ScottMadden with more than 30 years of experience in the energy industry. Tim has held senior positions at several gas utilities and energy consulting firms. His experience includes rates and regulatory support, sales and marketing, customer service and strategy development. Prior to joining ScottMadden, Tim served as Vice President of Sales and Marketing for Vermont Gas. He has also served as Vice President of Marketing and Regulatory Affairs for Providence Gas Company, Director of Rates at Boston Gas Company, and Project Director at Quantec, LLC, an energy consulting firm.

Tim has sponsored testimony and evidence before 23 state regulatory commissions and 2 Canadian regulatory boards. Tim holds a B.A. from St. Anselm College, an M.A. in Economics from The Pennsylvania State University, and an M.B.A. from Babson College.

Areas of Specialization

- Regulation and Rates
- Retail Energy
- Utilities
- Natural Gas

Capabilities

- Regulatory Strategy and Rate Case Support
- Strategic and Business Planning
- Capital Project Planning
- Process Improvements

Articles and Speeches

- "Country Strong: Vermont Gas shares its comprehensive effort to expand natural gas service into rural communities." ***American Gas Association***, June 2011 (with Don Gilbert).
- "Talking Safety With Vermont Gas." ***American Gas Association***, February 2009 (with Dave Attig).
- "Consumers Say 'Act Now' To Stabilize Prices." ***Power & Gas Marketing***, September/ October 2001 (with Jim DeMetro and Gerry Yurkevicz).
- "Rate Reclassification: Who Buys What and When." ***Public Utilities Fortnightly***, October 15, 1991 (with John Martin).

Sponsor	Date	Docket No.	Subject
Regulatory Commission of Alaska			
Cook Inlet Natural Gas Storage Alaska, LLC	7/21	Docket No. U-21-058	Sponsored testimony supporting the lead-lag study/cash working capital requirement for a general rate case proceeding.
ENSTAR Natural Gas Company	06/16	Docket No. U-16-066	Adopted and sponsored testimony supporting a lead-lag study for a general rate case proceeding.
Arizona Corporation Commission			
Southwest Gas Corporation	12/21	Docket No. G-01551A-21-0368	Sponsored testimony supporting class cost of service, rate design and bill impact analysis for a general rate case proceeding.
Arkansas Public Service Commission			
Liberty Utilities (The Empire District Electric Company)	2/23	Docket No. 22-085-U	Sponsored testimony supporting the class cost of service, rate design, bill impact studies, and revenue decoupling for a general rate case proceeding.
Liberty Utilities (Pine Bluff Water)	10/18	Docket No. 18-027-U	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding.
California Public Utilities Commission			
Bear Valley Electric Service, Inc.	10/22	Application No. 22-08-010	Sponsored testimony supporting marginal cost study, rate design and bill impact analysis for a general rate case proceeding.
Liberty Utilities (CalPeco Electric)	5/21	Application No. 21-05-017	Sponsored testimony supporting the lead-lag study/cash working capital, marginal cost study, rate design and bill impact analysis for a general rate case proceeding.
Southwest Gas Corporation (Southern California, Northern California, and South Lake Tahoe jurisdictions)	8/19	Application No. 19-08-015	Sponsored testimony on behalf of three separate rate jurisdictions supporting revenue requirements, lead-lag/ cash working capital, and class cost of service, rate design and bill impact analysis for a general rate case proceeding.
Connecticut Public Utilities Regulatory Authority			
Yankee Gas Company	07/14	Docket No. 13-06-02	Sponsored report and testimony supporting the review and evaluation of gas expansion policies, procedures and analysis.
Illinois Commerce Commission			
Ameren Illinois Company d/b/a Ameren Illinois	1/23	Docket No. 22-0487	Sponsored testimony supporting a Multi-Year Integrated Grid Plan (Grid Plan). Prepared research and analysis evaluating the reasonableness of the Grid Plan through comparison to how other electric utilities have responded to the changing energy landscape.
Liberty Utilities (Midstates Natural Gas)	07/16	Docket No. 16-0401	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new commercial classes and a decoupling mechanism.
Iowa Utilities Board			

Sponsor	Date	Docket No.	Subject
Liberty Utilities (Midstates Natural Gas)	07/16	Docket No. RPU-2016-0003	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new commercial classes.
Kansas Corporation Commission			
The Empire District Electric Company	12/18	Docket No. 19-EPDE-223-RTS	Sponsored testimony supporting cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.
Kentucky Public Service Commission			
Bluegrass Water Utility (Central States Water Company)	02/23	Case No. 2022-00432	Sponsored testimony supporting the rate design and bill impact studies for a general rate case proceeding.
Maine Public Utilities Commission			
Maine Water Company	03/21	Docket No. 2021-00053	Sponsored testimony supporting a proposed rate smoothing mechanism.
Northern Utilities, Inc. d/b/a Unitil	06/19	Docket No. 2019-00092	Sponsored testimony supporting a proposed capital investment cost recovery mechanism.
Northern Utilities, Inc. d/b/a Unitil	06/15	Docket No. 2015-00146	Sponsored testimony supporting the proposed gas expansion program, including a zone area surcharge.
Maryland Public Service Commission			
Sandpiper Energy, a Chesapeake Utilities company	12/15	Case No. 9410	Sponsored testimony supporting the cost of service, rate design and bill impact studies for a general rate case proceeding. The testimony includes proposal for new residential and commercial classes.
Massachusetts Department of Public Utilities			
Berkshire Gas Company, Eversource Energy, Liberty Utilities, National Grid, and Unitil	03/22	Docket No. DPU 20-80	Sponsored report that summarizes research, findings, and recommendations for regulatory mechanisms, methodologies, and policies that support Massachusetts's achievement of its net zero climate goal by 2050. The regulatory designs were informed by the results of quantitative and qualitative analysis of decarbonization pathways to achieve the Commonwealth's climate goals.
Liberty Utilities (New England Gas Company)	08/20	Docket No. DPU 20-92	Sponsored the Long-Range Forecast and Supply Plan filing for the five-year forecast period 2020/2021 through 2024/2025.
Eversource Energy, National Grid, and Unitil	02/20	Docket No. DPU 19-55	Sponsored report that summarizes research and evaluation of funding approaches for infrastructure modifications that interconnect Distributed Generation (DG) projects.
Liberty Utilities (New England Gas Company)	07/18	Docket No. DPU 18-68	Sponsored the Long-Range Forecast and Supply Plan filing for the five-year forecast period 2018/2019 through 2022/2023.
Liberty Utilities (New England Gas Company)	07/16	Docket No. DPU 16-109	Sponsored the Long-Range Forecast and Supply Plan filing for the five-year forecast period 2016/2017 through 2020/2021.

Sponsor	Date	Docket No.	Subject
Boston Gas	10/93	Docket No. DPU 92-230	Sponsored testimony describing the Company's position regarding rate treatment of vehicular natural gas investments and expenses.
Boston Gas	03/90	Docket No. DPU 90-55	Sponsored testimony supporting the weather and other cost of service adjustments, rate design and customer bill impact studies for a general rate case proceeding.
Boston Gas	03/88	Docket No. DPU 88-67-II	Sponsored testimony supporting the rate reclassification of commercial and industrial customers for a rate design proceeding.
Michigan Public Service Commission			
Lansing Board of Water & Light and Michigan State University	04/20	Docket No. U-20650	Sponsored testimony evaluating Consumer Energy's cost of service and rate design proposals.
Lansing Board of Water & Light and Michigan State University	04/19	Docket No. U-20322	Sponsored testimony evaluating Consumer Energy's cost of service and rate design proposals.
Midland Cogeneration Ventures, LLC	09/18	Docket No. U-18010	Sponsored testimony evaluating Consumer Energy's cost of service and rate design proposals.
Minnesota Public Utilities Commission			
Northern States Power Company (XcelEnergy)	10/21	Docket No. E002/GR-21-630	Sponsored testimony supporting a Return on Equity (ROE)adjustment mechanism that would allow the Company to symmetrically adjust its ROE to reflect significant changesin financial market conditions.
Missouri Public Service Commission			
Confluence Rivers Utility Operating Company	12/22	Case No. WR-2023-0006/ SR-2023-0007	Sponsored testimony supporting the rate design and bill impact studies for a general rate case proceeding.
The Empire District Gas Company	08/21	Docket No. GR-2021-0320	Sponsored testimony supporting the cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.
The Empire District Electric Company	05/21	Docket No. ER-2021-0312	Sponsored testimony supporting the cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding.
Spire Missouri, Inc.	12/20	Docket No. GR-2021-0108	Sponsored testimony supporting class cost of service, rate design, and lead-lag study proposals for a general rate case proceeding. The testimony also included support for a proposed revenue adjustment mechanism.
The Empire District Electric Company	08/19	Docket No. ER-2019-0374	Sponsored testimony supporting the cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding. The testimony also included proposals for a weather normalization mechanism.
Liberty Utilities (Midstates Natural Gas)	09/17	Docket No. GR-2018-0013	Sponsored testimony supporting the cost of service, rate design, bill impact and lead-lag studies for a general rate case proceeding. The testimony also included proposals for a revenue decoupling/ weather normalization

Sponsor	Date	Docket No.	Subject
			mechanism as well as tracker accounts for certain O&M expenses and capital costs.
Missouri Gas Energy	04/17	Docket No. GR-2017-0216	Sponsored testimony supporting the cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding. The testimony included support for a decoupling mechanism.
Laclede Gas Company	04/17	Docket No. GR-2017-0215	Sponsored testimony supporting the cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding. The testimony included support for a decoupling mechanism.
Nevada Public Utilities Commission			
Southwest Gas Corporation	09/21	Docket No. 21-09001	Sponsored testimony supporting the class cost of service,rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
Southwest Gas Corporation	02/20	Docket No. 20-02023	Sponsored testimony supporting the class cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
New Hampshire Public Utilities Commission			
Unitil (Northern Utilities, Inc.)	8/21	Docket No. DG 21-104	Sponsored testimony supporting a revenue decoupling mechanism.
Unitil Energy Systems, Inc.	4/21	Docket No. DE 21-030	Sponsored testimony supporting a revenue decoupling mechanism.
Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities	11/17	Docket No. DG 17-198	Sponsored testimony supporting a levelized cost analysis for approval of firm supply and transportation agreements.
Liberty Utilities d/b/a Granite State Electric Company	04/16	Docket No. DE 16-383	Adopted testimony and sponsored Lead/Lag study for a general rate case proceeding.
New Jersey Board of Public Utilities			
South Jersey Gas Company	04/22	Docket No. GR22040253	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Elizabethtown Gas Company	12/21	Docket No. GR21121254	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
South Jersey Gas Company	03/20	Docket No. GR20030243	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Elizabethtown Gas Company	04/19	Docket No. GR19040486	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Pivotal Utility Holdings, Inc. d/b/a Elizabethtown Gas Company	08/16	Docket No. GR16090826	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.

Sponsor	Date	Docket No.	Subject
Corporation Commission of Oklahoma			
The Empire District Electric Company	02/21	Cause No. PUD 202100163	Sponsored testimony supporting the cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding. The proposed rate design included a three-year phase-in of the proposed rate increase.
The Empire District Electric Company	03/19	Cause No. PUD 201800133	Sponsored testimony supporting the cost of service, rate design, bill impact and Lead/Lag studies for a general rate case proceeding.
The Empire District Electric Company	04/17	Cause No. PUD 201600468	Adopted direct testimony and sponsored rebuttal testimony supporting the revenue requirements for a general rate case proceeding. The testimony included proposals for alternative ratemaking mechanisms.
Rhode Island Public Utilities Commission			
Providence Gas Company	08/01 09/00 08/96	Docket No. 1673	Sponsored testimony supporting the changes in cost of gas adjustment factor related to projected under-recovery of gas costs; Filed testimony and witness for pilot hedging program to mitigate price risks to customers; Filed testimony and witness for changes in cost of gas adjustment factor related to extension of rate plan.
Providence Gas Company	08/00	Docket No. 2581	Sponsored testimony supporting the extension of a rate plan that began in 1997 and included certain modifications, including a weather normalization clause.
Providence Gas Company	03/00	Docket No. 3100	Sponsored testimony supporting the de-tariff and deregulation of appliance repair service, enabling the Company to have needed pricing flexibility.
Providence Gas Company	06/97	Docket No. 2581	Sponsored testimony supporting a rate plan that fixed all billing rates for three-year period; included funding for critical infrastructure investments in accelerated replacement of mains and services, digitized records system, and economic development projects.
Providence Gas Company	04/97	Docket No. 2552	Sponsored testimony supporting the rate design, customer bill impact studies and retail access tariffs for commercial and industrial customers, including redesign of cost of gas adjustment clause, for a rate design proceeding.
Providence Gas Company	02/96	Docket No. 2374	Sponsored testimony supporting the rate design, customer bill impact studies and retail access tariffs for largest commercial and industrial customers for a rate design proceeding.

Sponsor	Date	Docket No.	Subject
Providence Gas Company	01/96	Docket No. 2076	Sponsored testimony supporting the rate reclassification of customers into new rate classes, rate design (including introduction of demand charges), and customer bill impact studies for a rate design proceeding.
Providence Gas Company	11/92	Docket No. 2025	Sponsored testimony supporting the Integrated Resource Plan filing, including a performance-based incentive mechanism.
Railroad Commission of Texas			
Texas Gas Service Company – West Texas, North Texas, and Borger/ Skellytown Service Areas	06/22	Case No. 00009896	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – Central Texas and Gulf Coast Service Areas	12/19	GUD No. 10928	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
CenterPoint Energy – Beaumont/ East Texas Division	11/19	GUD No. 10920	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – Borger/ Skellytown Service Area	08/18	GUD No. 10766	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – North Texas Service Area	06/18	GUD No. 10739	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
CenterPoint Energy – South Texas Division	11/17	GUD No. 10669	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Texas Gas Service Company – Rio Grande Valley Service Area	06/17	GUD No. 10656	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Atmos Pipeline – Texas	01/17	GUD No. 10580	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
CenterPoint Energy – Texas Gulf Division	11/16	GUD No. 10567	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Public Utility Commission of Texas			
CenterPoint Energy Houston Electric, LLC	04/19	Docket No. 49421	Sponsored testimony supporting the Lead/Lag study for a general rate case proceeding.
Vermont Public Utilities Commission			
Vermont Gas Systems	12/12	Docket No. 7970	Sponsored testimony describing the market served by $90 million natural gas expansion project to Addison County, VT. Also described the terms and economic benefits of a special contract with International Paper.
Vermont Gas Systems	02/11	Docket No. 7712	Sponsored testimony supporting the market evaluation and analysis for a system expansion and reliability regulatory fund.
Virginia State Corporation Commission			
Rappahannock Electric Cooperative	10/22	Case No. PUR-2022-00160	Sponsored report and studies related to revenue requirements, class cost of service, rate design, and bill impact analysis for a streamlined application to increase base rates.

Sponsor	Date	Docket No.	Subject
American Electric Power - Appalachian Power Company	3/20	Case No. PUR-2020-00015	Sponsored testimony supporting the Lead/Lag study for the 2020 triennial review of base rates, terms, and conditions.
Nova Scotia Utility and Review Board			
Nova Scotia Power	01/22	Matter No. M10431	Sponsored evidence supporting the cash working capital requirement and lead/Lag study for a general rate case proceeding.
Ontario Energy Board			
Ontario Energy Association	01/21	Docket No. EB-2020-0133	Sponsored evidence regarding policies and ratemaking treatment related to COVID-19 costs in U.S. and Canadian regulatory jurisdictions. The evidence was used to support Ontario Energy Association's response to Staff's proposals

EXHIBIT JC-12

BEFORE THE
NEW JERSEY BOARD OF PUBLIC UTILITIES

In the Matter of the Verified Petition of Jersey Central Power & Light Company for Review and Approval of Increases in, and Other Adjustments to, Its Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith

Direct Testimony
of
John C. Ahr

RE: JCP&L Advanced Metering Infrastructure Program

EXHIBIT JC-12

DIRECT TESTIMONY OF JOHN C. AHR ON BEHALF OF
JERSEY CENTRAL POWER & LIGHT COMPANY

I. INTRODUCTION AND PURPOSE

Q. Please state your name and business address.

A. My name is John C. Ahr. My business address is 800 Cabin Hill Drive, Greensburg, PA 15601.

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

A. I am employed by FirstEnergy Service Company, which is a direct subsidiary of FirstEnergy Corp. ("FirstEnergy"), the parent company of Jersey Central Power & Light Company ("JCP&L" or "Company"), as an Advisor, Regulatory Compliance - Smart Meter.

Q. How long have you worked for FirstEnergy Service Company?

A. I have worked for over thirty-eight years with subsidiaries of FirstEnergy or its predecessor companies, working in a variety of positions in the engineering, operations, customer services, transmission, customer support, energy efficiency and the emerging technology program and strategy areas of the company.

Q. Please describe your duties and responsibilities as Advisor, Regulatory Compliance – Smart Meter.

A. In this role, I am responsible for regulatory compliance associated with all FirstEnergy smart meter projects, including all filings, and resulting regulatory processes associated with plan implementation and approval. I also provide leadership, expert guidance, management, and subject matter expertise for the smart meter projects and coordinate smart meter developments among the FirstEnergy operating companies. I further serve as the

smart meter subject matter expert and represent the smart meter projects and FirstEnergy's operating companies on regulatory matters.

Q. Please describe your educational background and professional experience.

A. I am a graduate of The Pennsylvania State University with a Bachelor of Science Degree in Electrical Engineering. I have also earned a master's degree in business administration from the University of Pittsburgh. I began work with FirstEnergy or its predecessor companies in 1984 as an Engineer in the distribution planning area and was promoted to the Supervisor of Transmission & Distribution Operations in 1992. I subsequently held several management positions until I was promoted to Director of System Operations in 1999. Other positions I have held include: Director of Energy Procurement; Director of Meter Reading and Collections; Senior Consultant; Manager, Customer Support and Manager, Regulatory Compliance – Smart Meter.

Q. Have you previously testified in New Jersey Board of Public Utilities ("BPU") proceedings?

A. Yes. I provided pre-filed testimony on behalf of JCP&L in the Matter of the Verified Petition of JCP&L for Approval of an Advanced Metering Infrastructure ("AMI") Program ("JCP&L AMI Program" or "AMI Program") in BPU Docket No. EO20080545. I have also testified before the Pennsylvania Public Utility Commission ("PaPUC") in the 2009 Petition of West Penn Power Company d/b/a Allegheny Power for Expedited Approval of its Smart Meter Technology Procurement and Installation Plan and in formal customer complaint proceedings related to smart meters before the PaPUC on behalf of all of FirstEnergy's Pennsylvania distribution companies. I have also provided testimony before

the West Virginia Public Service Commission, the Maryland Public Service Commission, and the Public Utilities Commission of Ohio.

Q. Please describe and summarize the content of your testimony

A. My testimony discusses the JCP&L AMI Program and the Company's progress toward O&M savings described in the AMI Program.

Q. Are there any schedules associated with your direct testimony?

A. Yes. JCA-1 is a pro forma sheet showing an updated projection (as of January 31, 2023) of operational benefits associated with the Company's AMI Program.

Q. What is advanced metering infrastructure or "AMI"?

A. AMI, as presented in the *2019 Energy Master Plan: Pathway to 2050* ("EMP"), is "a foundational component of a modernized electric distribution grid and uses an integrated system of smart meters, communications networks, and data management systems to enable two-way communication between utilities and customer."[1]

Q. Has the BPU determined that the deployment of AMI is necessary to achieve the goals set forth in the 2019 EMP?

A. Yes. The EMP states that "Statewide AMI installation is a prerequisite of many additional clean energy objectives as laid out in this EMP."[2] The EMP further states that "AMI has many benefits, but many can only be realized if the utility both invests in the needed data handling infrastructure and creates customer programs that leverage the new AMI

[1] *See* EMP, §5.3.1: Evaluate a strategic and coordinated rollout of Advanced Metering Infrastructure, at 184 (2019).
[2] *Id.*

capabilities."[3] The BPU has found that "AMI has the potential to benefit the distribution system, streamline and modernize utility operations, provide an enhanced customer experience, and benefit the environment."[4]

Q. Please provide an overview of JCP&L's AMI Program to deploy smart meters throughout its service territory.

A. On August 27, 2020, JCP&L filed a petition with the BPU for approval of its JCP&L AMI Program in BPU Docket No. EO20080545. Under the AMI Program, the Company proposed to install approximately 1.15 million advanced meters and other AMI throughout its service territory over an accelerated multi-year period, resulting in AMI benefits to its residential, commercial, and industrial customers. As filed, the AMI Program included an estimated investment in plant in service of approximately $360.0 million, an estimated incremental O&M cost of approximately $73.3 million and approximately $30.8 million of cost of removal.

The Company proposed to deploy AMI in accordance with the following schedule:

- Pre-Deployment Phase (beginning no later than January 1, 2022 and continuing through December 31, 2022)
- Deployment Phase (January 1, 2023 - December 31, 2025)
- Final Engineering Phase (January 1, 2026 - December 31, 2027)

[3] *Id.*
[4] *In the Matter of the Petition of Rockland Electric Company for Approval Of an Advanced Metering Program; and For Other Relief,* BPU Docket No. ER16060524, Decision and Order (February 19, 2020) ("AMI Filing Order").

Q. Did the Company modify its proposal in any way?

A. Yes. The Company filed a Supplement to the Petition on September 14, 2021, which reflected an increase in the cost of the AMI Program. As described in the Supplement, the Company updated the projected costs to approximately $390 million in plant in service over the first six (6) years of the AMI Program, rather than the originally estimated approximately $360 million.

Q. Was the Company's proposed AMI Program, as supplemented, approved?

A. Yes, as modified by the Stipulation of Settlement ("Stipulation") that was filed on February 8, 2022 to resolve the Company's verified petition for approval of the AMI Program. The BPU issued an Order on February 23, 2022, to be effective March 1, 2022, adopting the Stipulation and finding "the Stipulation to be reasonable and in accordance with the law, striking an appropriate balance between the needs of customers and of the Company, while promoting competition."[5]

Q. Did the Stipulation modify the deployment timeline or costs as compared to the Company's original filed proposal?

A. While the timeframes for deployment did not change, the plant in service costs did increase by $30 million over the Company's initial filing as a result of changes in the assessment of overhead costs**.**

[5] *In the Matter of the Verified Petition of Jersey Central Power & Light Company for Approval of an Advanced Metering Infrastructure (AMI) Program (JCP&L AMI),* BPU Docket No. EO20080545, Decision and Order at 16 (February 23, 2022).

Q. Please identify and describe the commitments that JCP&L made as a part of the Stipulation that are to be addressed in this base rate case.

A. As part of the Stipulation, JCP&L agreed to provide in its next base rate case (i.e., the instant proceeding) testimony regarding its progress toward O&M savings described in the AMI Program.[6] JCP&L also agreed to provide testimony and actual cost information for monthly recurring fees paid by customers not participating in AMI meter reading, as well as the one-time fee for the removal of an AMI meter and re-installation of a conventional meter.[7] These fees are to be subject to review and modification, as necessary, in this proceeding.

Lastly, as part of the Stipulation, the Company agreed to include a proposed revenue requirement reduction pro forma in subsequent base rate cases for future AMI-related O&M savings. Schedule JCA-1 attached hereto meets this requirement. The AMI-related O&M savings are to reflect estimated savings for meter reading costs, meter re-read truck rolls, back-office activities, and the contact center, consistent with anticipated savings set forth in the AMI Petition. Furthermore, simultaneous with the filing of its proposed pro forma revenue requirement reduction, the Company will submit an anticipatory discovery response responding to the following Rate Counsel interrogatory: "Provide a comparison of the Company's O&M savings with the savings described in S-JCP&L-AMI-REV-12, including the reasons why specific savings were lesser or greater than projected." I will submit the anticipatory discovery response with responses to the first set of discovery received from BPU Staff.

[6] *See* Stipulation at 18, ¶37.
[7] *Id.* at 19, ¶39.

II. UPDATE ON PRE-DEPLOYMENT AND INITIAL DEPLOYMENT ACTIVITIES UNDER THE AMI PROGRAM

Q. Please describe the three phases of the deployment schedule set forth in JCP&L's AMI Program.

A. The Pre-Deployment-Phase began in the fourth quarter of 2021 and continued through December 2022. During the Pre-Deployment Phase, the AMI Program called for the Company to confirm its project team, assess market conditions and pricing, contract with key vendors, make arrangements for procurement of equipment and resources, develop construction and deployment schedules, and initiate the build-out of necessary information technology ("IT") infrastructure to support initial deployment.

The Deployment Phase began in January 2023 and will continue through December 2025. During the three-year Deployment Phase, the Company will conduct the mass deployment of smart meters to its mass market customer base of residential, commercial, and industrial customers (approximately 99% of all meters) absent unforeseen circumstances. Also, the Company will integrate the AMI system with an advanced distribution management system ("ADMS").

The Final Engineering Phase is a two-year period commencing January 2026 during which the Company will address communication challenged locations and install AMI-related equipment (e.g., range extenders and connected grid routers) to further strengthen its AMI communications network. During the Final Engineering Phase, these remaining 1% of customers (i.e., the customers that were not addressed in the Deployment Phase) will receive a smart meter and/or other communications solutions, except for (i) high-tension service (230 kV) customers taking service under Rate GT, who already have advanced

meters, and (ii) customers served under the Restricted Off-Peak and Controlled Water Heating special provisions of the Residential Service and General Service Classifications, which require specialty meters for which there is currently no compatible AMI replacement.

Q. Please provide further details regarding the work the Company completed during the "Pre-Deployment Phase."

A. During the Pre-Deployment Phase, the Company completed the scope of that phase as outlined above. The JCP&L AMI project team was confirmed, including external resources, given then-current market conditions and associated resource costs and availability. Contracts with key vendors were established including the meter supplier vendor, the meter deployment vendor and the meter retirement testing vendor. Meter supply orders were finalized, and construction and deployment schedules were set. Business process workshops with key internal stakeholders were held to develop business process documents covering AMI network equipment deployment, meter deployment, billing enablement, opt-out enablement, legacy meter retirement testing, and meter socket repairs. Business integration and IT teams used these documents to develop any new functionality and establish IT releases needed to support the AMI network and meter deployment. The change management part of the project team worked with corporate communications to develop customer communications, including pre-installation brochures, pre-installation notification letters and post-installation door hangers. Finally, they developed and delivered training to key internal stakeholders who are impacted by or play a role in smart meter deployment.

Q. Did the Company complete the Pre-Deployment Phase on time and on budget according to the AMI Program?

A. Yes. For the Pre-Deployment Phase work described previously, capital spend was approximately $29.45 million and incremental O&M spend was approximately $6.42 million, for an overall cost of $35.87 million. Forecasted capital spend for the Pre-Deployment Phase was approximately $39.26 million and forecasted incremental O&M was $12.52 million, for an overall cost of $51.78 million. The capital variance of $9.81 million was driven by lower ADMS implementation costs due to servers, workstation desktop tower and network cost actuals coming in lower than forecast and lower than forecast allocation across the project; lower than projected IT hardware costs due to adjustments in hardware allocations to other FirstEnergy AMI programs; the timing of onboarding labor of contractors and other FirstEnergy employees changing; and a lower than forecasted annual overhead rate adjustment compared to the actual overhead rate adjustment that occurred. The incremental O&M variance of $6.10 million was driven by lower ADMS implementation cost due to servers, workstation desktop tower and network cost actuals coming in lower than forecast and lower than forecast allocation across the project; and the timing of onboarding labor of contractors and other FirstEnergy employees changing.

Q. What are the next steps that the Company will be focusing on now that the Deployment Phase is underway?

A. The Company's focus now is on executing the updated deployment schedule and ensuring that the planned functionality of the complete end-to-end AMI solution is realized. This starts with ensuring that the appropriate quantities of materials and supplies are forecasted,

ordered, and received at the appropriate cross dock locations for the meter deployment vendor to move through the deployment schedule most efficiently. There is also a focus on monitoring the health of the AMI communications network as the field network equipment gets built out and commences bi-directional communications with the deployed AMI meters. There will also be a continuing effort to review and confirm that the newly established business processes, such as bill certification, are functioning as designed. As the Company is just at the beginning of the journey through the Deployment Phase, it is critical that these items be monitored to ensure deployment continues to move forward according to plan.

Q. Please provide an update on the Company's progress relative to the recently started "Deployment Phase."

A. Field installation of AMI network equipment began in January 2023. As of January 31, 2023, six connected grid routers have been installed in the Allenhurst area. The mass deployment of meters is scheduled to begin in March 2023 following the AMI communications infrastructure build-out and establishment of the AMI communication network. In the order requiring the filing of AMI plans, the BPU observed that "replacing aging standard meters with new standard meters, and not AMI smart meters, may … 'risk stranding the investments in newly installed meters that are no longer useful.' Therefore, the Board requests that the utilities be mindful to keep stranded costs to a minimum."[8] Being mindful of the BPU's request, the Company has installed over 31,766 AMI capable meters as of January 31, 2023 that will be considered smart meters once they are established on the AMI communications network.

[8] *See* AMI Filing Order at 3 (quoting EMP, §5.3.1, at 185).

Q. Based upon the efforts achieved by the Company during the Pre-Deployment Phase and the efforts scheduled for the Deployment Phase, does the Company have any anticipated updates to the deployment schedule at this time?

A. Yes. The original AMI Program filing provided an estimated schedule, for planning purposes, of the smart meter deployment timeframe including an estimated number of meters installed per year during the Deployment Phase. Originally, it was estimated that approximately 300,000, 400,000 and 400,000 meters would be installed each year over the three-year Deployment Phase, respectively. In collaboration with our meter supplier vendor and meter deployment vendor in establishing an updated deployment schedule, we are now estimating 275,000, 537,000, and 333,000 meters will be installed each year, respectively, over the three-year Deployment Phase.

III. AMI COSTS AND SAVINGS INCLUDED IN THE COMPANY'S CLAIM

Q. Under the Stipulation, what costs are the Company permitted to include in base rates as a part of this base rate case?

A. As presented in the Stipulation, AMI Program-related capital costs and legacy meter stranded costs shall be deferred and placed in regulatory assets, as separate and identifiable accounts, for recovery of the regulatory assets deemed prudent in the Company's subsequent base rate cases (i.e., filed following BPU approval of the Stipulation) that address costs related to the AMI Program. In subsequent base rate cases, at the Company's discretion, it may elect to include JCP&L AMI Program investments (i.e., for rolling in AMI Program costs to base rates for recovery) consistent with the JCP&L AMI cost recovery mechanism and deferral provisions set forth in the Stipulation.

Q. Does the Stipulation establish any Company obligations related to O&M expense associated with the AMI Program?

A. Yes. As stated in the Stipulation, the Company will either book or track, or some combination thereof, a regulatory asset ("AMI Investment Regulatory Asset") comprised of its AMI Program-related capital investment ("AMI Investment Deferral"). JCP&L will book a regulatory asset ("AMI Stranded Cost Regulatory Asset") comprised of the associated stranded costs on legacy meters ("AMI Stranded Cost Deferral"), as well as a regulatory asset comprised of the incremental O&M deferred costs associated with the AMI Program ("AMI O&M Deferral").

Q. Please describe what AMI Program-related costs the Company has determined to claim as a part of this base rate proceeding.

A. The AMI costs included in this proceeding are associated with the Company's start-up activities in the Pre-Deployment Phase and the beginning of the Deployment Phase. Pre-Deployment Phase costs include activities, licenses, and equipment used to support network deployment, and billing enablement for AMI solutions. These items amount to approximately $35.87 million (comprised of $29.45 million in capital investment and $6.42 million of incremental O&M expense). Deployment Phase costs forecasted through June 2023 include activities supporting network deployment, billing enablement, deployment enablement, and program governance. These items amount to a forecast of approximately $30.34 million (comprised of $22.68 million in capital investment and $7.66 million of incremental O&M expense). Additionally, the Company forecasts an additional $68.20 million in capital expenditures associated with the program from July 1, 2023 through December 31, 2023.

Q. How do these costs incurred compare to the projected costs set forth for these phases in the AMI Program and Stipulation?

A. To date, the costs for the Pre-Deployment Phase and the beginning of the Deployment Phase are tracking and align well with the costs anticipated in the AMI Program filing and Stipulation, with only limited updates. Capital expenses for the Deployment Phase are forecast to be approximately $19.3 million lower than the estimated investment in plant in service of approximately $390.0 million as presented in the Stipulation. Incremental O&M expenses during the Deployment Phase are forecast to be $1.78 million higher than the estimated incremental O&M cost of approximately $73.3 million as presented in the Stipulation. Cost of removal is forecasted to be $9.20 million lower than the estimated cost of removal of approximately $30.8 million as presented in the Stipulation.

Q. As you articulated above, the Company committed to "include a revenue requirement reduction pro forma in the subsequent base rate case for future AMI-related O&M savings." Has the Company included a revenue requirement reduction pro forma with AMI-related O&M savings in this case?

A. Yes. *See* Schedule JCA-1. There has been a slight decrease in the overall pro forma estimated savings from what was presented in the AMI Program filing. The overall benefits in the 20-year study period are forecast to be approximately $6.80 million lower than $394.62 million operational benefits as presented in the AMI Program filing. The primary driver to this reduction is an updated headcount based upon the actual 2022 headcount and an alignment to the finalized deployment schedule. As discussed above, the Company has just begun the Deployment Phase of its AMI Program in January of this year. While the Company expects to deploy approximately 43,000 meters in the first six months

of 2023, there are no cost savings that are expected to be realized within the test period for this case, which goes from July 1, 2022 through June 30, 2023 or in the period set forth for pro forma adjustments in *Elizabethtown*.[9] As such, JCP&L's pro forma adjustments to the Company's revenue requirement, as set forth in the testimony of Carol A. Pittavino (Exhibit JC-3), do not include an adjustment for anticipated O&M savings associated with the AMI Program.

Q. Why will there be no AMI-related O&M savings realized within the test period?

A. As presented in the AMI Program, a general assumption was that "[o]perational benefits were assumed to begin to be realized in year two of the Deployment Phase and then lag smart meter installation by three months thereafter to account for the build-out of the communications network. Customer and Societal Benefits were generally assumed to lag meter installation by twelve months before beginning to be realized in accordance with the participation levels assumed for each benefit stream."[10] As such, the Company does not expect benefit achievement to begin until 2024. In other words, until such time that AMI meters are deployed and able to communicate to the extent necessary that JCP&L may begin to alter its field and supporting operations, there will be no operational savings realized. Operational benefits identified in the AMI Program include reducing the meter reading function and reducing back office and call center costs due to a reduction from customer billing and meter reading inquiries. In support of achieving the described O&M savings, the Company has focused on developing a benefit tracking tool, has conducted

[9] *In re Elizabethtown Water Company Rate Case*, BPU Docket No. WR8504330, Decision on Motion for Determination of Test Year and Appropriate Time Period for Adjustments (May 23, 1985).
[10] *See* JCP&L Program, "General Financial Inputs and Assumptions", at 21 (Aug. 27, 2020).

meetings with benefit owners, and plans to track benefits monthly and review with benefit owners on a quarterly basis.

Q. Because the Company is not including a revenue requirement reduction with AMI-related O&M savings in this case, please comment on the Company's commitment to provide the Signatory Parties to the Stipulation with an anticipated discovery response to: "Provide a comparison of the Company's O&M savings with the savings described in S-JCP&L-AMI-REV-12, including the reasons why specific savings were lesser or greater than projected."

A. As presented in the Stipulation, the Company has committed to provide semi-annual status reports to Rate Counsel and the BPU not later than September 1 and March 1 of each year, reporting actual results through the preceding June 30 and December 31, respectively. The first semi-annual report is to be filed by September 1, 2023 and the second report by March 1, 2024. The metrics to be reported on include program costs, O&M expense, meter installation costs, network deployment costs, and stranded costs.

Q. Pursuant to Paragraph 37 of the Stipulation, has the Company tracked actual O&M cost savings during the Pre-Deployment and Deployment Phases under the AMI Program?

A. Yes. The Company has established accounts to track actual O&M cost savings associated with deployment of the AMI Program; however, as discussed earlier, such savings are not anticipated to materialize until the second year of AMI deployment.

Q. Will the Company continue to track actual O&M savings associated with the AMI Program?

A. Yes, it will.

Q. Does the Company expect to reflect a test year revenue requirement reduction with AMI-related O&M savings in a future base rate case?

A. Yes. The Company expects to realize a reduction in O&M expenses from AMI deployment, consistent with its projections, as reflected in the approved AMI Program. These AMI-related O&M reductions are assumed to begin to be realized in year two of the Deployment Phase and then lag smart meter installation by three months thereafter to account for the build-out of the communications network. The AMI-related O&M savings that occur within the test period would be reflected in test year expense in future base rate cases.

Q. Under the Stipulation, did the Company have any other reporting obligations?

A. Yes. As part of the semi-annual status reports, the Company will report on customer elections of the available opt-out provision within the Company's Tariff. The Company also committed to provide testimony and actual cost information for monthly recurring fees for customers not participating in AMI meter reading and the one-time fee for the removal of an AMI meter and re-installation of a conventional meter.

Q. Please identify and describe the costs that these fees are intended to recover.

A. There are two tariffed fees associated with a customer's opt-out of AMI metering. One is a monthly meter reading fee of $15.00 applicable to any customer who: (i) refuses to allow the Company to install a communicating AMI meter; (ii) requests that the transmitter of an AMI meter be disabled; or (iii) requests that an AMI meter be removed. A second one-time meter replacement fee of $44.46 is applicable to customers for the replacement of an AMI meter with a non-AMI meter. The replacement meter will be manually read. This fee will also apply to any customer who elects to participate in AMI metering after

requesting the removal of such meter. These fees are intended to recover the labor and travel expenses to read and/or exchange the meter.

Q. Please identify where the actual cost information associated with these opt-out fees are contained in the Company's filing.

A. JCP&L made its opt-out compliance filing with the BPU on December 23, 2022, to be effective with service rendered on and after January 1, 2023. The opt-out fees are included in section 3.24 Advanced Metering Opt-Out in the JCP&L tariff.

Q. Is the Company proposing any changes to these fees at this time?

A. No. As the Deployment Phase has just begun as of January 2023, there have been no opt-out fees imposed on any customer to provide a basis to modify these fees at this time. The opt-out fees will be applied once the meter reading route where the opt-out customer resides is being read through the AMI solution. The Company is not looking to impose an opt-out fee while the meters along the route continue to be read manually.

IV. CONCLUSION

Q. Does this conclude your testimony?

A. Yes, it does.

Exhibit JC-12
Schedule JCA-1

JERSEY CENTRAL POWER & LIGHT COMPANY
AMI Operational Benefits - 20-Year

As Filed August 27, 2020*
Operational Benefits – 20-Year
Millions

Operational	Type	Total
Meter Reading	O&M	($341.39)
Meter Reading	Capital	($1.81)
Meter Services	O&M	($49.28)
Meter Services	Capital	($0.38)
Back Office	O&M	($0.72)
Call Center	O&M	($1.04)
Total Operational Benefits		($394.62)

Updated January 31, 2023
Operational Benefits – 20-Year
Millions

Operational	Type	Total
Meter Reading	O&M	($331.99)
Meter Reading	Capital	($1.81)
Meter Services	O&M	($52.17)
Meter Services	Capital	($0.38)
Back Office	O&M	($0.93)
Call Center	O&M	($0.54)
Total Operational Benefits		($387.82)

Difference
Operational Benefits – 20-Year
Millions

Operational	Type	Total
Meter Reading	O&M	($9.40)
Meter Reading	Capital	$0.00
Meter Services	O&M	$2.89
Meter Services	Capital	$0.00
Back Office	O&M	$0.21
Call Center	O&M	($0.50)
Difference		($6.80)

*AMI Plan Section 3.3. Potential Operational Benefits

EXHIBIT JC-13

BEFORE THE
NEW JERSEY BOARD OF PUBLIC UTILITIES

In the Matter of the Verified Petition of Jersey Central Power & Light Company for Review and Approval of Increases in, and Other Adjustments to, Its Rates and Charges for Electric Service, and for Approval of Other Proposed Tariff Revisions in Connection Therewith

Direct Testimony
of
Kenneth A. Strah

RE: Customer Experience and Low-Income Programs

Introduction

Q. Please state your name and business address.

A. My name is Kenneth A. Strah. My business address is 76 South Main Street, Akron, Ohio 44308.

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

A. I am employed by FirstEnergy Service Company ("FESC") as Vice President, Customer Care.

Q. Please discuss your professional experience and educational background.

A. I have been with FirstEnergy Corp. ("FirstEnergy") or its predecessor utilities or subsidiaries for over forty years, over half of which has been in the Customer organization and in leadership positions. I have a Bachelor of Arts in Business Administration from Baldwin-Wallace College. My full qualifications are set forth on Appendix A to my testimony.

Q. Please state the purpose of your testimony.

A. I am testifying on behalf of Jersey Central Power & Light Company ("JCP&L" or "Company") in support of its base rate case filing. More specifically, my testimony addresses the customer-focused initiatives that FESC has implemented over the last 18 to 24 months. Some of these initiatives are part of an ongoing effort to enhance customers' experience. I also testify about two new low-income assistance initiatives that JCP&L is proposing. These new programs are a direct result of FirstEnergy's enhanced customer-focused engagement.

Customer Experience Initiatives

Q. Please discuss FirstEnergy's Customer Experience initiatives that have been developed and rolled out in 2021-2022.

A. FirstEnergy has undertaken a comprehensive structural and functional redesign of its organizations that provide direct support to its customers. FirstEnergy has more than six million customers throughout its footprint, and senior management recognized that the Company needed to focus more directly on the customer's needs from the customer's perspective.

As a result, the customer-oriented business units were reorganized around a more customer-centric model. This organization is led by a Senior Vice President of Customer Experience. Customer Experience is comprised of the following areas, the first three of which directly support the customer experience of FirstEnergy's operating companies, including JCP&L: Customer Care, Customer Engagement, Customer Policy & Solutions and Competitive Products & Services. Each of these groups have a distinct area of focus, but also strive on an interrelated basis to provide each FirstEnergy customer with the best possible experience and service.

Q. Can you explain the role of the Customer Care organization?

A. Yes. The Customer Care organization is a major functional unit under the Senior Vice President of Customer Experience. Its core functions are those that one commonly associates with customer operations, such as customer contact centers, revenue operations, customer management (including billing, electric supplier support) and customer support functions. However, these areas have been re-focused to emphasize the customer's role in service and operational issues, working in concert with the Customer Engagement

organization, with a goal of enhancing the customer's overall experience with FirstEnergy's utilities.

Customer Care's core function is ensuring the environment, tools, technologies, and policies can protect and meet the needs of our communities. The team executes strategies to enhance the customer experience, while meeting regulatory commitments and operational excellence. Significant contributions of the Customer Care team in 2022 include flexible staffing and training to respond to the changing external environment, market, and customer needs. Additionally, the team began a multi-year effort to replace the customer-facing core systems to provide a more seamless, robust omni-channel environment that has begun implementation already and will be officially complete in 2024. This new customer experience platform offers the most innovative application that supports omni-channel routing, analytics, artificial intelligence, and workforce optimization, while delivering continuous improvement opportunities. Automation continues to be another significant effort aimed at creating efficiencies in many of the operational areas, including billing, collections scheduling, and reporting. The collections scheduling process also partnered with Experian to optimize account management and prudency. Digital Collections was piloted in early 2022 and met a much higher success rate than traditional customer engagement channels (such as telephone) in connecting with customers. Through these digital campaigns, FirstEnergy was able to reach customers earlier in their delinquency period to resolve issues and move them to payment plans or assistance programs that were better suited to their individual needs.

Q. Can you explain what the Customer Engagement group does?

A. Yes. Customer Engagement came together to innovate and unlock best practices to support customers and employees to align with the goal of being in the first quartile in customer experience (as measured by the Engaged Customer Relationship or "ECR" metric). The team has built an Engagement Plan framework for all FirstEnergy customers, including residential, commercial, and industrial. This group provides insights into customer behaviors, expectations, and opinions. Additionally, the Customer Engagement team takes a proactive approach to protecting consumers privacy, along with other best practices for data governance. Key achievements in 2022 include the broadening of the Voice of the Customer program via a digital survey, which has a deeper reach into the customer base and has already provided significant customer feedback on key processes for enhancement. The Customer Engagement team also implemented a broadcast tool which, once the customer opts in, will aid in proactively reaching the customer in varying scenarios which impact their reliability or rates.

Within Customer Engagement is the Economic Development organization, which has a dedicated staff that works to attract traded sector companies into our service territory, as well as helping existing traded sector customers to expand their operations in the FirstEnergy service territories. Many of these customers, including manufacturers, data center operators, research and development facilities and headquarter operations, are energy intensive and electric service is a key driver in their site selection analysis. The Economic Development organization serves as trusted energy advisors and is committed to making customers' lives brighter, the environment better and our communities stronger. This group works closely with state organizations and their network partners, as well as

regional and local economic development organizations, consultants, local governments, brokers, developers, universities, peer utilities and other interested parties.

Another group under Customer Engagement is the Energy Efficiency organization, which develops and helps to implement a broad range of energy efficiency and peak demand reduction programs for residential, low income, commercial, governmental, and industrial customers. These efforts are designed to help meet or exceed each state's long-term energy and sustainability goals. The team educates customers on their energy usage and recommends ways they can improve their overall energy efficiency and conservation efforts. In conjunction with states' various regulatory programs, the group offers incentives and rebates for customers to upgrade their homes or facilities with more efficient and cost-effective technologies and promotes behaviors that reduce energy consumption. Combined, these efforts help customers save money on their electric bills and minimize carbon footprints.

The Customer Support & National Accounts group is dedicated to supporting larger customers (commercial and industrial), including multi-site national customers that may have accounts in multiple FirstEnergy service territories. Some of the key support services this group manages include new service and property upgrades, billing and site information requests, and storm and outage planning and response. This organization also works with larger customers to provide electrification support, such as electric vehicle adaptation and energy efficiency measures.

Q. Are there other functions under the Customer Experience organization?

A. Yes. There is also a Customer Policy & Solutions group.

Q. What is the role of the Customer Policy and Solutions team within the Customer Experience organization?

A. The Customer Policy and Solutions team develops, advocates for, and delivers products and solutions that customers want from regulated utilities, that comply with legislative and regulatory requirements and advance corporate objectives. For example, the team has been making strides in educating our communities about electric vehicle and solar programs, as well as developing additional information that can be accessed by customers in varying engagement channels. The team has begun working on an organization-wide policy and advocacy roadmap for customer electrification and affordability.

Currently, the group's primary focus is to advance electric transportation adoption, as it is rapidly gaining momentum with regulators, legislators, auto manufacturers, and customers. The expectation is that the scope will expand in the future into other electrification technologies such as building HVAC, industrial processes, and perhaps behind the meter renewable energy.

Q. Do the units within the Customer Experience organization engage in cross-functional initiatives?

A. Yes. In addition to each unit's core functions, there is significant cross-department engagement. For example, low-income programs and digital innovation are two such areas.

Through cross-department initiatives, the group has identified an impactful approach to connecting with low-income eligible program customers. The team identified new means to reach customers in need or at risk through video campaigns, employee ambassadors, and targeted communications. The group utilized third party vendors in 2022

to reach communities via digital channels, such as email. By doing so, FirstEnergy saw a 55% increase in the number of customers who qualified for human service programs compared to the same period in the previous year. The campaigns were designed to relay the ease of enrollment and make the experience to connect customers with agencies intuitive and targeted.

Similarly, with respect to digital innovation, the Customer Experience team led a cross-department effort that was able to empower customers and enhance experiences through items such as mobile-friendly information and visuals, a redesign to outage reporting and additional education to consumers so that they could harness self-service features and have more information at their fingertips. To start this effort, teams were formed to focus on the customer's specific digital journey. These teams, partnered with information technology teams, took a "Design Thinking" approach to put the customer experience first and ensure that the customer's views and feedback were captured by seeking their opinions in focus groups and surveys, as well as by assessing consumer behavior via research and analytics such as speech-to-text. Agile environment teams were able to roll out dozens of new digital features for customers across the key customer journeys of Outage, Move In/Move Out, and Payment/Billing.

Q. Please explain how the restructured Customer Experience organization will benefit JCP&L customers.

A. As I discussed earlier, FESC has deployed the restructured Customer Experience organization throughout the entire FirstEnergy footprint, including across New Jersey. All JCP&L's customers – residential, commercial, governmental and industrial – will benefit from an enhanced customer experience.

Specifically, for the JCP&L service territory, there has been a focus on low-income assistance as an area in need of additional attention. The JCP&L service territory has a fairly high percentage of customers that are senior citizens, with a significant portion of these qualifying as income-limited. Therefore, the Customer Experience organization has developed two new proposed low-income assistance programs. I discuss these in the next section of this testimony.

Low-Income Assistance Initiatives

Q. Please discuss the new initiatives that JCP&L is proposing to assist low-income customers.

A. The Company is proposing two new initiatives. I will discuss each in turn. The first is the "Energy Assistance Outreach Team." The purpose of the team is to increase awareness, education and participation in energy assistance programs that are available to income-limited customers. The team will partner with targeted organizations and strengthen the relationships within the community.

Q. What specific activities will the team assist customers with?

A. On a broad level, the team will assist income-limited customers with learning about and applying for assistance programs that will help with their utility costs. More specifically, the team will:

- Be responsible for education, resources, tools, and technology needed to reduce and/or eliminate customer barriers to program participation;
- Work with customers, agencies, local charities, churches and local governments to understand the types of available programs;
- Help customers by sharing what information is required to participate in the different programs;

- Participate in energy assistance fairs and organize additional events as necessary; and
- Offer a more hands-on support system for agencies to assist with special situations or barriers.

Q. Why is JCP&L proposing the Energy Assistance Outreach Team?

A. A centralized, dedicated team to assist customers with information about and enrollment in all the assistance programs that customers are eligible for will be a benefit to both customers and the Company. Customers will be more likely to receive assistance paying their electric bills and the Company will likely see a decline in uncollectible expense.

Q. Will JCP&L have dedicated team members for its service territory?

A. Yes. While FirstEnergy plans to deploy the program throughout each of its operating utilities, there will be full-time staff dedicated to the JCP&L service territory.

Q. What is the second initiative?

A. The second initiative is called the "Senior Citizen Discount Program."

Q. Please explain what this program will entail.

A. The Senior Citizen Discount program will provide a percentage discount on the distribution component of the bill that, on average, results in a monthly bill credit of approximately $15, to income-eligible senior customers for their primary residence. The discount will be applied as a credit to the distribution-portion of the participating customer's monthly bill.

Q. How was the Senior Citizen Discount determined?

A. The discount was informed by a similar program that has been in place for FirstEnergy's customers in West Virginia since the early 1980's. In this program, eligible customers receive a discount on their total bill (given it is a vertically integrated utility). Based on the experiences from that program and the different dynamics in New Jersey in terms of

usage and market structure, the Company is proposing a discount on the distribution component of the bill, that represents a bill credit of approximately $15.[1]

Q. What are the eligibility criteria for enrollment into this program?

A. The eligibility criteria are as follows:

- Customer must be 65 years of age or older;
- Customer may only receive the discount for their primary residence;
- Customer has participated in certain energy assistance programs (Home Energy Assistance Program ("HEAP"), Emergency HEAP, Payment Assistance for Gas and Electric ("PAGE"), New Jersey SHARES, and Lifeline) within any of the rolling twelve months prior to or including the month of enrollment;
- Customer may not be an active participant in USF; and
- Customer must have made a payment or received energy assistance within the past 30 days to receive the monthly discount.

Q. How long does enrollment last upon application and confirmation of eligibility?

A. Twelve months. Following each enrollment period, a customer must be recertified.

Q. Can a customer participate in this program at the same time as the USF program?

A. No. This program is intended to provide alternative support to customers that do not qualify for USF. For such customers, it is intended to be complimentary to the other customer assistance programs they will have participated in, such as the HEAP, the Emergency HEAP, the PAGE program, the New Jersey SHARES program, and the New Jersey Lifeline program.

Q. Will customers in arrears be able to participate in the program?

A. Yes, as long as they meet all eligibility criteria outlined above.

[1] Based on average residential usage of 780 kWh per month and the proposed rates in this filing.

Q. What is JCP&L's reason for excluding customers participating in the USF program?

A. JCP&L chose to exclude USF participants from the discount program to avoid impacting the function of the calculated USF benefits. The proposed discount will reduce the customer's energy burden, which is a factor in calculating benefits for USF, and could potentially impact the customer's eligibility to enroll for a monthly credit and/or arrears forgiveness. It could also reduce the monthly USF credit.

Q. How will customers enroll in the Senior Citizen Discount Program?

A. JCP&L will conduct outreach to customers that participated in eligible programs to explain the Senior Citizen Discount Program. Additionally, JCP&L conducts outreach via multiple channels to explain available programs – bill inserts, press releases, call campaigns, email campaigns, social media, and handouts delivered by field personnel. This program would be included in those materials.

Customers interested in enrolling in the program will need to contact the Company's Customer Care Center. JCP&L will use customer account information to verify the customer's birthdate and energy assistance participation. If the customer's birth date is not already on file, JCP&L will use Accurint[2] to validate the birth date of an applicant to minimize the need to request proof of age from the customer.

Q. Why is JCP&L proposing the Senior Citizen Discount Program?

A. The JCP&L service territory has a large number of senior citizens. Approximately 13% of JCP&L's residential customers are senior citizens (approximately 135,853 customers). There were 9,016 residential customers in this demographic that were not a participant in

[2] Accurint is a secure third-party application provide by LexisNexis that allows clients with approved access to search for and validate information about individuals or businesses using public records searches.

New Jersey's USF program that would qualify for the senior discount and who received some other type of assistance within the past 12 months. The Senior Citizen Discount Program will provide energy bill assistance to income-restricted seniors while simultaneously assisting in reducing the Company's level of uncollectible expense.

Q. What is JCP&L's budget for these two initiatives?

A. The annual JCP&L budget for these initiatives is $2.5 million.

Q. What are the components of the annual budget?

A. The largest component of the budget is the monthly bill discount under the Senior Citizen Discount Program and the administrative costs.

Q. When does JCP&L plan to roll out both the Energy Assistance Outreach Team and the Senior Citizen Discount Program?

A. The Company expects to commence these programs during 2023, subject to the receipt of regulatory approvals.

Q. Does that conclude your testimony at this time?

A. Yes, it does.

Appendix A
Resume: Education and Experience of Kenneth A Strah

Education:

1992 - Bachelor of Arts in Business Administration from Baldwin-Wallace College

Experience:

1980-1994	Various Clerical Positions - Cleveland Electric Illuminating Co & Centerior Service Company
1994-1998	Rates/Business Analyst – Rates Department - Centerior Service Co.
1999-2000	Business Analyst – Transmission Regulatory Affairs – FirstEnergy Service Company
2001-7/2001	Advance Business Analyst – Business Services – FirstEnergy Service Company
8/2001-2004	Regional Billing Supervisor – Northern Region – FirstEnergy Service Company
2004-2008	Manager, Meter Reading – Meter Reading- FirstEnergy Service Company
2008-2009	Director, Meter Reading – Meter Reading- FirstEnergy Service Company
2009-2011	Manager, Process & Performance Analytics – Customer Service – FirstEnergy Service Company
2011-2013	Director, Customer Service Analytics – Customer Service- FirstEnergy Service Company
2013-2018	Director, Revenue Operations & Customer Service Analytics – Customer Service- FirstEnergy Service Company
2018- 10/2021	Director, Customer Contact Centers -Customer Service- FirstEnergy Service Company

10/2021 to Present VP, Customer Care